IN THE AUSTRALIAN COMPETITION TRIBUNAL

AGL ENERGY LIMITED

1 of 2014

RE: PROPOSED ACQUISITION OF MACQUARIE GENERATION (A CORPORATION ESTABLISHED UNDER THE ENERGY SERVICES CORPORATIONS ACT 1995 (NSW))

ANNEXURE CERTIFICATE

This is the annexure marked "**DP2**" annexed to the affidavit of **DANIEL ENOCH PRICE** dated 26 March 2014

Annexure DP 2

Filed on behalf of (name & role of party) AGL Energy Limited
Prepared by (name of person/lawyer) Liza Carver
Law firm (if applicable) Ashurst Australia
Tel +61 2 9258 5897 Fax +61 2 9258 6999
Email Liza.Carver@ashurst.com
Address for service (include state and postcode) Level 35, 225 George Street, Sydney, NSW, 2000 DX 388 Sydney

[Form approved 01/08/2011]

General Industry Report

A REPORT PREPARED FOR ASHURST

24 March 2014

Subject to legal professional privilege

General Industry Report

Contents

General Industry Report

Figures

Tables

1 Authorship

1 I, Daniel Enoch Price, hold the position of co-owner and Managing Director of Frontier Economics Pty Ltd, an economics consulting firm based in Melbourne, Australia, a position I have held since 1999. I hold a degree of Bachelor of Agricultural Economics from the University of Sydney. I have 25 years experience specialising in the economics of the energy sector. Over this time I have been involved in a wide range of matters relating to the design and implementation of energy reforms, regulatory policies, trading and contracting strategies, contract negotiations and energy asset transactions.

2 Prior to founding Frontier Economics in 1999, I was the Managing Director of another consultancy firm, London Economics. Prior to being a consultant I was a Principal Economist at the New South Wales Electricity Commission. In this role I was heavily involved in the design of the Australian NEM rules and industry structure.

3 I have been assisted in writing this report by Liam Blanckenberg, Simone Wong and Rajat Sood, who are employees of Frontier Economics and hold Honours degrees in economics from the University of Melbourne.

2 Design of the NEM

2.1 Background

4 The National Electricity Market (NEM) is the interconnected power system that services the eastern seaboard Australian states and territories of New South Wales (NSW), Victoria, Queensland, South Australia, Tasmania and the Australian Capital Territory (ACT).

5 The NEM commenced on 13 December 1998. The original NEM jurisdictions were NSW and Victoria. Queensland, South Australia, the ACT and Tasmania joined subsequently.[1]

6 The NEM operates over the world's longest interconnected power system – from Port Douglas in Queensland to Port Lincoln in South Australia and Hobart in Tasmania – a distance of more than 5000 kilometres (kms). The majority of electricity demand (or 'load') is concentrated in a relatively narrow band within 100km or so of the coast. To serve such a widely distributed load, the NEM incorporates over 750,000 kms of distribution network lines and 40,000kms of transmission network lines.[2]

7 In 2012/13, the NEM supplied 199 TWh of energy to 9.3 million customers. This energy was supplied by 317 registered generators, with a total installed capacity of 48,321MW.[3] Total turnover in the wholesale market in 2012/13 was $11.4 billion.[4]

8 Generators in the NEM compete with one another by making offers to the market and system operator, the Australian Energy Market Operator (AEMO),[5] to supply specified volumes of power at specified prices. AEMO selects generators to run (be 'dispatched') using an algorithm that seeks to minimise the overall cost of meeting demand having regard to both:

- Price-quantity offers submitted by generators (and large customer loads); and

---

1 See http://www.aemc.gov.au/Electricity/Electricity-Market.html (accessed 11 March 2014).

2 Australian Energy Market Commission, *The Australian National Electricity Market: Choosing a New Future*, World Energy Forum 13-16 May 2012, Quebec City, Canada, Conference Paper delivered by John Pierce, Chairman, p.6, available at: http://www.aemc.gov.au/media/docs/John-Pierce-Conference-Paper---World-Forum-on-Energy-Regulation---16-May-2012-7be3476d-b91c-496e-a3d1-89bad07fdf47-0.PDF (accessed 11 March 2014).

3 Australian Energy Regulator, *State of the Energy Market 2013*, p.20, available at: http://www.aer.gov.au/node/23147 (accessed 11 March 2014).

4 Australian Energy Market Operator, *Fact Sheet – The National Electricity Market*, available at: http://www.aemo.com.au/About-the-Industry/Energy-Markets (Accessed 11 March 2014).

5 Prior to 1 July 2009, the NEM market and system operator was the National Electricity Market Management Company (NEMMCO).

- Power system constraints – such as thermal and stability limits on transmission lines – which may prevent the cheapest generators being fully dispatched to supply the total amount of power they have offered.

9 In effect, AEMO's dispatch algorithm dispatches generators from cheapest to most expensive, subject to prevailing power system constraints. Other things being equal, a generator offering to supply power at a low price will be dispatched ahead of a generator offering to supply power at a higher price.

10 While generators in the NEM are dispatched so as to minimise the aggregate cost of supply to all loads at all locations, pricing and settlement takes place on a regional basis. The NEM is a 'zonal' market containing five pricing and settlement regions, which broadly correspond to jurisdictional boundaries.[6] As explained further below, a single settlement price is determined for each region reflecting demand and supply conditions at a location within each region known as the 'regional reference node' (or 'RRN'). This 'regional reference price' (or 'RRP') is the price reflecting the marginal value of electricity at the RRN and it is the price at which all generators and customers in the region are settled in respect of their wholesale electricity sales and purchases.

11 Although pricing and settlement is determined on a regional basis, electricity can flow between regions through high voltage transmission lines known as interconnectors. Interconnectors allow generators in one region to supply customers in another, thereby increasing the effective supply of power in the 'importing' region and the effective demand in the 'exporting' region. In this way, interconnector power flows can help equalise demand and supply conditions across different regions.

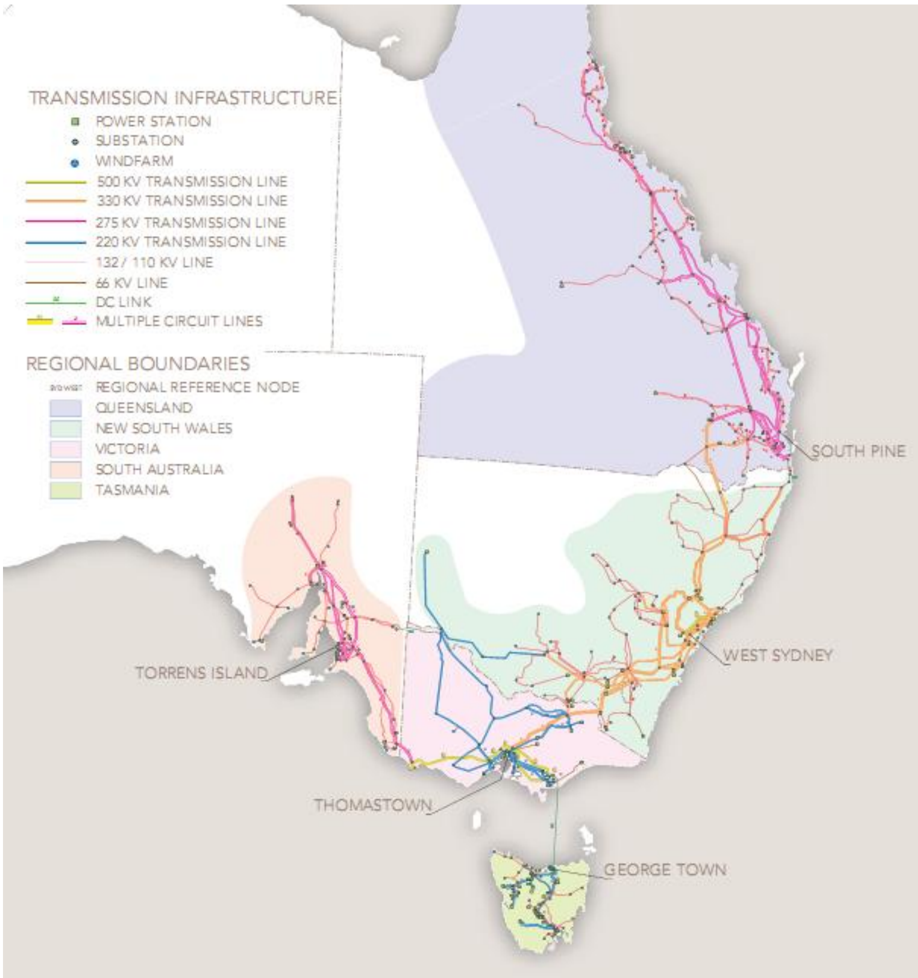
12 When no power system constraints are binding across the NEM, all RRPs in the market will be the same, allowing for the value of electrical losses incurred through the transportation of electricity from one location to another. This is because in the absence of constraints, the marginal cost of meeting an increment of electricity demand at any location in the NEM will be the same (again, allowing for losses). For example, without any binding constraints, a generator in Victoria could meet an increase in demand anywhere in the 5,000 km-long power system. If transmission constraints bind, different regions' RRPs will diverge, reflecting the fact that the marginal cost of meeting an increase in demand in different regions will vary. This is explained in greater detail in section 2.4 below.

13 A map showing the geographic coverage of the NEM, the key transmission lines and the identity of each RRN is shown in Figure 1 below.

---

6 A 6th NEM region, Snowy, was abolished in 2008.

Figure 1: The National Electricity Market



Source: AEMO (2009). An Introduction to Australia's National Electricity Market, December 2009

2.2 Electricity supply industry organisation

2.2.1 Particular characteristics of electricity

14 Electricity has several unique characteristics that affect the way the electricity supply industry is organised:

- It is widely used throughout the economy, as an input in the production of other goods and services and by end-use customers
- It cannot be stored, except in a very limited way, such as batteries
- It has unusual technical characteristics (such as voltage and frequency) which mean that supply and demand must be matched at all times to avoid the power system becoming unstable and dangerous

Contents

- It is homogeneous, so it is not possible to distinguish whether electricity consumed by a customer originated from one generator or another
- Demand is highly unresponsive to prices, (ie 'inelastic'), especially in the short term
- Electricity supply infrastructure – particularly transmission and distribution networks – exhibits strong 'natural monopoly' characteristics. This means that left to market forces, these parts of the industry may tend towards monopoly.

2.2.2 Industry arrangements

15 The Australian electricity supply industry is based around the activities of generation, transmission, distribution and retailing. Generation involves the production of electrical energy from other forms of energy such as coal, gas or water flow. Transmission is the long-distance bulk transport service for electricity between producers (generators) and high voltage customers. Distribution networks carry electricity from the edge of transmission networks to the premises of customers needing power at low and medium voltages. Retailing is the activity of managing relationships with end-use customers, including billing customers for their power consumption.

16 Investment in transmission and distribution networks is characterised by significant economies of scale and discreteness or 'lumpiness' of asset size and capacity. Further, power tends to flow through such networks across multiple parallel paths, creating what economists call 'loop flow externalities'. Together, these attributes mean that the planning, development and operation of transmission and distribution networks can usually be most efficiently provided by a single party. As a result, transmission and distribution networks are often regarded by economists as 'natural monopolies' and policy-makers impose regulation on the behaviour and returns of transmission and distribution network service providers (TNSPs and DNSPs, respectively). In Australia, such regulation caps the revenues and/or prices of TNSPs and DNSPs in respect of the provision of services for which competition is unlikely to be viable.

17 The particular characteristics of electricity and the natural monopoly features of networks, as well as the legacy of public ownership and intervention, have collectively given rise to a detailed set of regulatory arrangements governing the operation of the NEM. These are discussed below.

2.3 Regulatory arrangements

2.3.1 National Electricity Law

18 The National Electricity Law (the Law) provides the legislative framework for the NEM. Section 7 of the Law provides that the NEM Objective is:

> "…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> a) price, quality, safety, reliability and security of supply of electricity; and
>
> b) the reliability, safety and security of the national electricity system."

19 The Law prescribes the functions to be performed by statutory bodies such as the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER) and Australian Energy Market Operator (AEMO).

2.3.2 National Electricity Rules

20 The National Electricity Rules (the Rules) set out the rules and processes that govern, *inter alia*:

- participation in the NEM by different categories of participant and registration requirements
- the operation of the NEM, including the operation of the wholesale spot market as well as metering and wholesale settlements
- retail billing and settlement
- technical standards for participants
- the maintenance and restoration of power system security
- the economic regulation of TNSPs and DNSPs, including network connection processes and charges for conveyance services
- market administration
- participant and jurisdictional 'derogations' from the standard Rules.

2.4 Key characteristics of the NEM

21 The NEM can broadly be described as having the following features:

- Compulsory gross pool – all electricity traded in the NEM must be bought and sold through the centralised spot market operated by AEMO unless otherwise exempted.
- Energy-only – unlike some markets elsewhere (e.g. in the United States), the NEM has no capacity market or similar mechanism to explicitly enable

generators to recover their fixed capacity costs; this means that all generators' costs must be recovered through wholesale spot prices or derivatives settled against wholesale spot prices.

- Bid-based, security-constrained dispatch – generators and some loads compete to be dispatched by submitting offers and bids, respectively, to AEMO, who dispatches the cheapest available plant to meet demand while ensuring the system operates within the applicable technical limits.
- Regional settlement – the NEM has 5 pricing regions for the purposes of settlement, with separate prices (RRPs) established at each RRN. The RRP is defined as the marginal cost (based on participant bids and offers) of supplying an additional MW of electricity at the RRN.

22 The remainder of this section explains each of these characteristics in more detail.

2.4.1 Compulsory gross pool

23 The NEM is a compulsory 'gross' electricity pool market. This is in contrast to a 'net' or voluntary pool design. The distinguishing characteristic of a gross pool model is that all power (unless exempted) must be traded through a centralised spot market (managed in the NEM's case by AEMO) and all traded power is settled at the relevant spot price(s).

24 An alternative design to a gross pool is a net pool model, whereby producers and consumers can enter into bilateral contracts for the physical supply of electricity and only uncontracted power flows are settled through the market. An example of a net pool model is the BETTA (British Electricity Trading and Transmission Arrangements), originally introduced as NETA (New Electricity Trading Arrangements) in 2001. In this market, only electricity that has not already been contracted between parties is traded, and hence a 'balancing' market operation occurs only on the margin.

2.4.2 Energy-only market

25 The NEM is an energy-only market, meaning that investors in generation plant are remunerated solely through the wholesale spot market and the voluntary derivative contracts that are settled against spot market outcomes. Unlike some markets elsewhere (including most United States electricity markets), the NEM lacks a 'capacity market' or similar mechanism to explicitly enable generators to recover the fixed costs of their capacity.

26 The energy-only design of the NEM means that generators must be able to recover their variable operating costs as well as their fixed capital costs through spot market revenues and related derivative contracts. This implies that the spot price must be able to at least occasionally rise above the operating cost of the plant with the highest operating costs in the market in order to enable that plant

(typically a gas 'peaking' plant) to recover its fixed costs. When this happens, other generators with lower operating costs (such as coal-fired 'baseload' plant) also receive a price in excess of their operating costs and a contribution towards their fixed costs.

27 If the spot price is higher or remains high longer than necessary to enable existing generators to recover their total (fixed and operating) costs, this provides an incentive to investors to develop more plant. If the spot price is insufficient to enable existing generators to recover their fixed costs, investors receive an incentive not to develop more plant and some existing plant may be partly or wholly shut down or 'mothballed' until conditions improve.

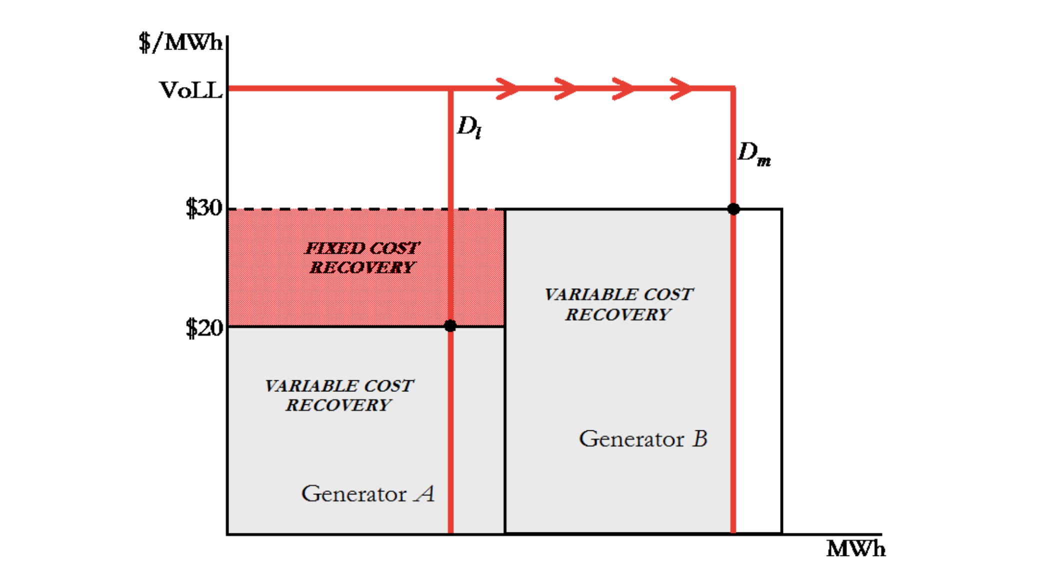
28 The unique characteristics of electricity outlined above mean that the spot price in an energy-only market can be very volatile. Indeed, if there is insufficient supply to meet demand for even a few moments, there may be no price at which the market will clear. In these circumstances of 'market failure', the market and system operator will be required to shed load involuntarily and set a price for the remaining transactions that are able to take place.

29 For these reasons, the NEM incorporates a market price cap (the 'MPC', formerly the 'Value of Lost Load' or 'VoLL'), at which the spot price is set if supply cannot meet demand. The MPC is presently $13,100/MWh, which is well above the operating costs of the highest operating cost plant in the NEM. The MPC is set so high to ensure that generators – particularly peaking generators – are able to recover both their variable *and* fixed costs over those short periods when supply is insufficient to meet demand. This is designed to encourage enough generation investment to ensure that periods of involuntary load shedding are relatively rare. Specifically, the current NEM reliability standard is that no more than 0.002% of energy demand is left unserved.

30 Figure 2 and Figure 3 below illustrates these concepts graphically. Assume two generators (A and B) utilise different technologies. Generator A is a coal-fired plant used for baseload supply and has a relatively low short-run marginal cost (SRMC) of supply. Generator B is a gas-fired plant used for peaking supply and has a relatively high SRMC of supply. Demand is a sideways "L-shape" since demand is perfectly inelastic for prices below the MPC.

31 At times of low demand (D_l) only Generator A is selected to run (in line with least-cost dispatch) and hence the spot price is set at $20/MWh. Since this is equal to Generator A's SRMC, this generator is recovering only its *variable* costs of supply.

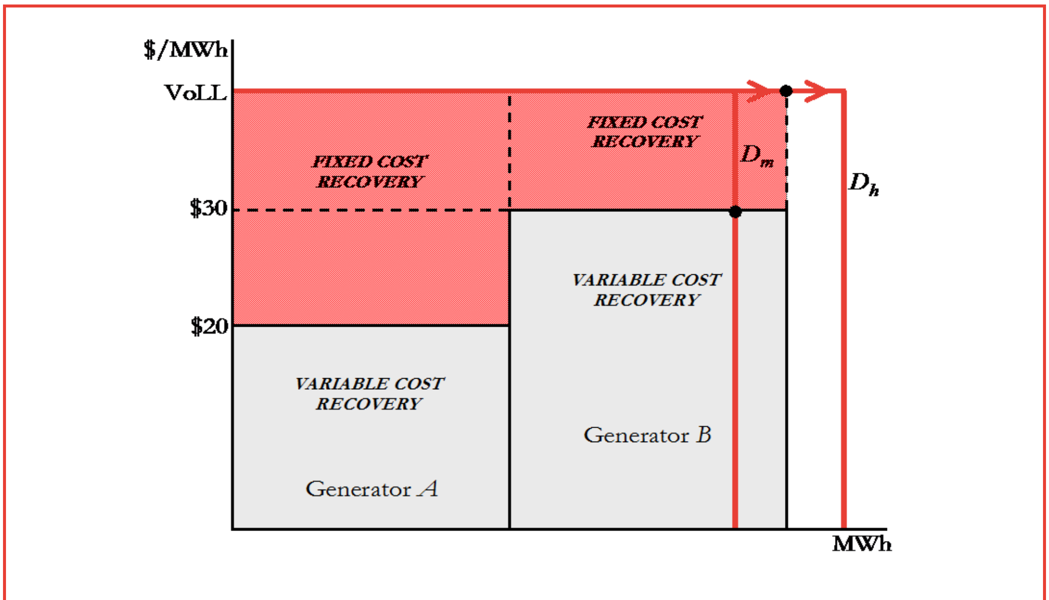
Figure 2: Recovery of fixed costs during times of medium demand



Source: Frontier Economics

32 At times of medium demand (D_m) both Generator A and B are selected to run and hence price is set at $30/MWh. Since $30/MWh is greater than Generator A's SRMC of $20/MWh, during times of medium demand Generator A recovers both its variable costs and some contribution towards its fixed costs. Since $30/MWh is equal to Generator B's SRMC, this generator is recovering only its variable costs of supply.

Figure 3: Recovery of fixed costs during times of high demand



Source: Frontier Economics

33 At times of high demand (D_h), where demand outstrips supply, price will approach the MPC and thus both generators will recover their variable costs of supply *and* some contribution towards their fixed costs.

2.4.3 Bid-based security-constrained dispatch

Dispatch process

34 As the market and system operator, AEMO manages the centralised, bid-based security-constrained dispatch process in the NEM. Generators compete for dispatch by submitting offers to AEMO to supply certain quantities of electricity (in megawatts or MW) at various prices. Prices can vary between the market floor price (-$1,000/MWh) and the MPC (currently $13,100/MWh). Customers (typically large loads such as aluminium smelters) can also participate in dispatch by making bids to reduce their consumption of electricity at specified prices. Both bids and offers are informally and collectively referred to as 'bids'.

Generator offers

35 To arrange the optimal dispatch of scheduled power stations in the NEM, generators are required to provide AEMO with offers by 12.30pm Eastern Standard Time (AEST) each day for each half-hour 'trading interval' for the following day. The trading day commences at 4.00am AEST. The offers specify:

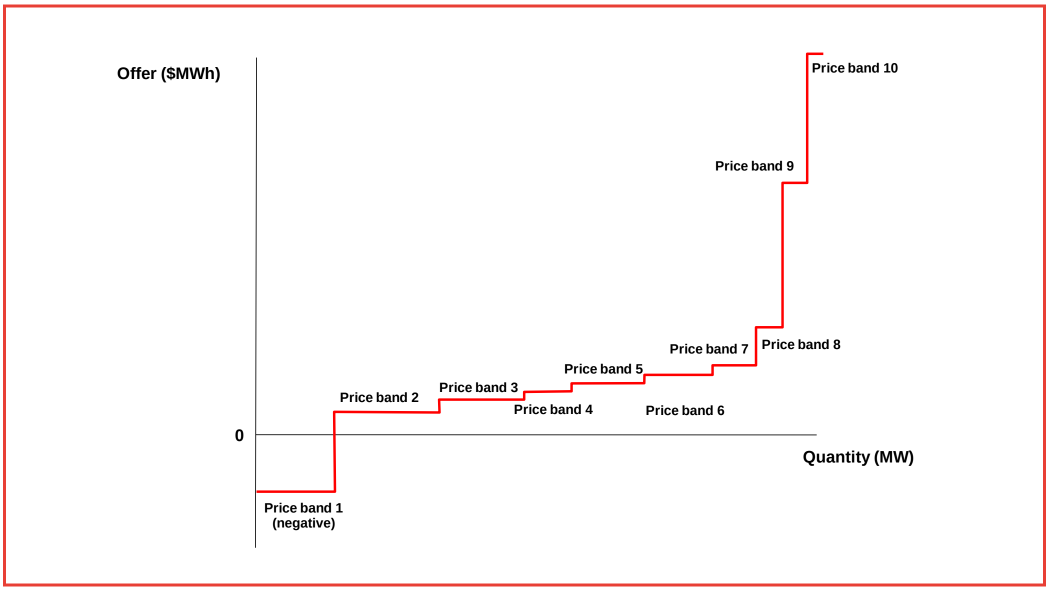
- the price(s) at which the generators are willing to produce electricity
- the quantity that they are willing to offer at each price.

Generators must provide ten choices of prices, known as price 'bands'. There are a number of restrictions on the price bands:

- There must be at least one negative price band. This is required to manage the case in which there is more generation offered at a zero price than is required to meet demand. If this is the case some generators may want to pay (receive a negative price) to avoid being switched off by AEMO. This is because it is relatively expensive and time consuming for some generators, particularly coal fired generator, to switch on and off.
- The price offered by a generator must be strictly increasing, with subsequent price bands being no lower than the previous band. This is a requirement of the dispatch algorithm.

36 Figure 4 provides an example of a stylised bid stack.

Figure 4: Illustrative generator offer



Source: Frontier Economics

37 Once final bids have been submitted, generators are not allowed to change the prices they have offered in each band. These prices apply over the trading day. However, generators can change how much (in MW) they are willing to supply at each price band and in each trading interval. Such behaviour is known as 'rebidding'. Rebidding allows generators to manage the risk of not being able to meet the quantities previously promised. Such risks may arise due to circumstances such as a plant failure. Rebidding also provides a means for generators to attempt to stimulate higher spot prices, which may be profitable.

Dispatch engine

38 In determining dispatch outcomes, AEMO utilises the National Electricity Market Dispatch Engine (NEMDE). NEMDE is an optimisation program that has the objective of selecting generators (or loads) to produce (or reduce consumption of) electricity in such a way that ensures total supply is equal to total demand across the market at the lowest feasible cost, subject to the physical limits of the transmission network. 'Cost' in this context refers to the prices specified in the bids and offers submitted by participants. Importantly, these prices may diverge from participants' actual resource costs of providing more supply or reducing demand.

39 In a market with no binding transmission limits or transmission losses, the plant that offers to produce electricity for the lowest price gets selected by the NEMDE to run first, with more expensive plants selected as cheaper offers are exhausted. The last unit of plant dispatched to meet demand is referred to as the marginal generator and the offer price of this plant sets the spot price across the entire market.

40 However, in reality, the NEM (like other electricity markets) experiences both transmission losses and constraints. Both losses and constraints can lead to spot prices varying from location to location. Electrical losses arise due to resistance on power lines and the dissipation of energy through heat as it is transported. Generally speaking, the further electricity is transported and the closer a transmission line is operating to its rated thermal limit, the higher losses will be on that line. Transmission constraints arise when the dispatch of certain generators to meet demand must be limited to avoid over-loading the technical capability of the network. Both constraints and losses are explained in more detail below.

41 The presence of transmission losses and constraints has significant implications for both dispatch of the market as well as pricing and settlement.

42 The key implication of transmission losses and constraints for the dispatch of the market is that demand may not always be met by the lowest-priced bids and offers. Instead, NEMDE may find that it is necessary to dispatch more expensive generators located close to load centres to minimise transmission losses or to avoid overloading the network. The dispatch outcome will still be least-cost under the circumstances, but some low-cost generators may not be fully utilised.

43 The implications of transmission constraints and losses for pricing and settlement are discussed in section 2.4.4 below.

Security constraints

44 In dispatching the system in a least-cost manner, the market operator, AEMO, must remain within predefined security and reliability parameters. The capacity of the transmission network is limited by certain technical characteristics. In broad terms these are known as thermal and stability limits[7]:

- Thermal limits – refer to the heating of transmission lines as more power is sent across them. The additional heat causes the lines to sag closer to the ground. The clearance above ground level must comply with certain minimum heights to ensure both public safety and power system security
- Stability limits – refer to the need to keep the transmission system operating within design tolerances for voltage and to ensure the system has the ability to recover from unexpected disturbances.

45 Network constraints are represented in the dispatch process through constraint equations. AEMO formulates constraint equations for inclusion in the central dispatch process to ensure that the patterns of dispatch appropriately reflect the physical limitations of the network. There are several thousand constraints that are taken into account by AEMO in the dispatch process. Many of these

[7] AEMC, *Congestion Management Review: Issues Paper*, March 2007, p. 11.

constraints are designed to accommodate contingencies in the power system; for example, the removal of a transmission line from service due to an outage.[8] More generally, AEMO changes the constraints it utilises in the dispatch process over time in response to changing network and power system conditions.

46 As the physical characteristics of the transmission network change over time due to network augmentations, extensions and asset replacements, the constraint equations AEMO uses to represent the physical characteristics of the power system also change. Changes to constraint equations lead to changes in patterns of dispatch and pricing outcomes.

Unconstrained dispatch

47 Figure 5 contains a simplified merit order to illustrate this process. In this example, it is assumed that there are only two regions in the NEM – NSW and Victoria – each with two generators capable of producing 100 MW of power. The combined demand for electricity across both states is assumed to be 250 MW. It is assumed that there is an interconnection of unlimited capacity between NSW and Victoria, which allows the cheapest power stations to be dispatched independent of location. Transmission losses and plant capabilities to respond to AEMO dispatch instructions are also ignored, though they can affect the pattern of dispatch and create geographic price differences within and between regions.

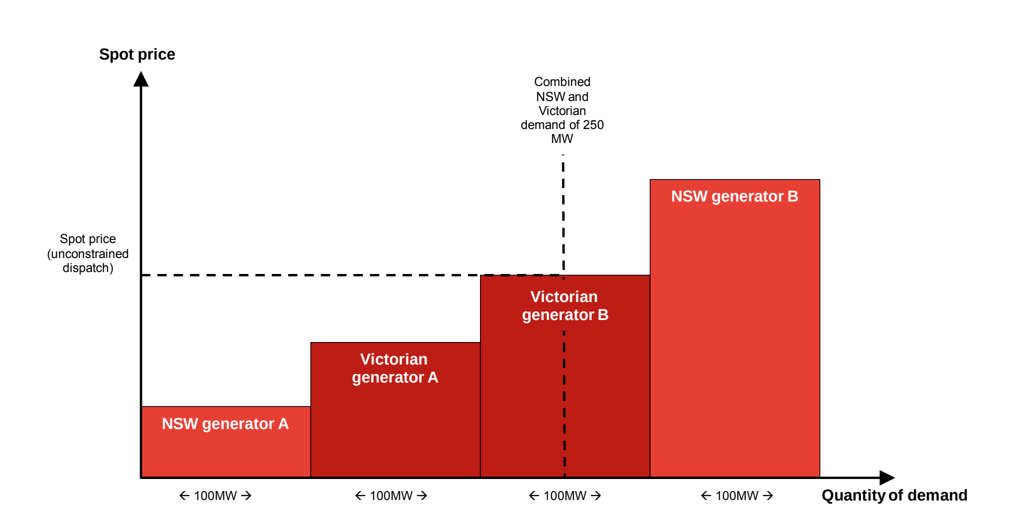
48 Faced with these supply and demand conditions, the NEMDE would stack the generation offers from the cheapest (NSW Generator A) to the most expensive (NSW Generator B), and then dispatch only those plant required to meet demand. This would result in all of the output offered by the NSW Generator A, Victorian Generator A and half of the output offered by Victorian Generator B being dispatched.

49 Since Victorian Generator B is the most expensive plant dispatched, its offer price will be used to determine the spot price at that time. This same spot price will prevail across the interconnected NEM – all RRPs will be identical. All the dispatched generators earn this spot price irrespective of their offer price. All customers buying electricity from the spot market will be required to pay this price.

---

8 AEMC, *Congestion Management Review: Directions Paper*, March 2007, p. 21.

Figure 5: Simplified example of NEM dispatch



Source: Frontier Economics.

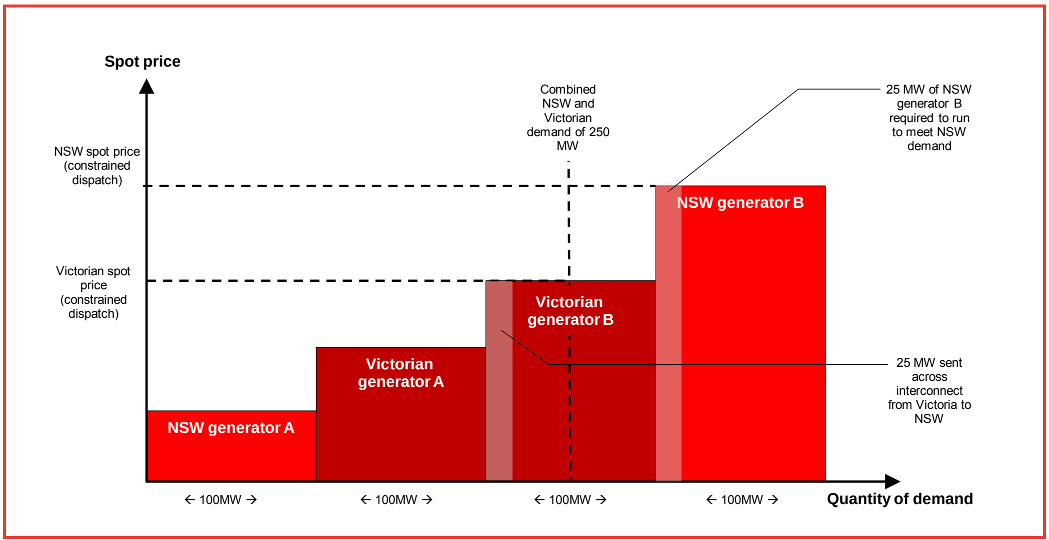
Constrained dispatch

50 In the example above, it is assumed that the capacity of transmission links between the regions is such that the cheapest power stations can be dispatched to the output levels the generators have offered. However, at times there is insufficient transmission capacity available to allow the cheapest power stations to run to meet demand across the NEM. At these times, AEMO has to override the schedule of generator offers and send instructions to the next most expensive power station that is not limited by transmission constraints to operate to a level that meets demand. In that case, the power station dispatched 'out-of-merit-order' generally sets the price in the region in which it is dispatched. This results in RRPs varying across the NEM at the same point in time.

51 Figure 6 contains a simple example of the process of spot price determination accounting for transmission constraints. This example builds on the example provided in Figure 5. In this example, it is assumed that there is a 25 MW interconnect between NSW and Victoria, and that demand for electricity in NSW is 150 MW and in Victoria is 100 MW. All other aspects of the example remain the same.

Contents

Figure 6: Simplified example of NEM dispatch, with constraints



Source: Frontier Economics.

52 Faced with these supply and demand conditions, AEMO will dispatch 100 MW of NSW Generator A, 100 MW of Victorian Generator A (which meets all of the 100 MW Victorian load), dispatch as much of Victorian Generator B as the interconnect will allow (which is only 25 MW) to be exported to meet NSW demand, and dispatch 25 MW of NSW Generator B to meet the remainder of NSW demand.

53 Under these circumstances, instead of a single spot price prevailing across the interconnected NEM, there are separate RRPs for NSW and Victoria. Under the transmission constraint conditions, the NSW RRP is set by the most expensive power station dispatched in NSW (NSW Generator B) and the Victorian RRP is set by the most expensive power station dispatched in Victoria (Victorian Generator B). This means the NSW price is higher than the Victorian price. All customers in NSW pay, and all NSW generators earn, the NSW RRP, while all Victorian customers pay, and all Victorian generators earn, the Victorian RRP.

Network Losses

54 Approximately eight to ten per cent of the electricity transported across the network between power stations and customers is lost due to the electrical resistance of the lines.[9] The amount of electricity lost depends primarily on the flow across the network, but is also dependent on factors such as the ambient temperature and the voltage of the lines (high voltage lines tend to lose less energy than low voltage lines when transporting a given amount of power).

---

9 Australian Government, *Report of the Prime Minister's Task Group on Energy Efficiency*, July 2010, p.164, available at: http://ee.ret.gov.au/sites/default/files/documents/03_2013/report-prime-minister-task-group-energy-efficiency.pdf (accessed 12 March 2014).

55 Spot prices in the NEM are adjusted to take into account the effect of transmission network losses. The losses associated with the transfer of electricity between two points are approximated using marginal loss factors. Marginal loss factors estimate the electrical losses of each additional increment of electricity transmitted between connection points. There are two types of transmission marginal loss factors in the NEM:

- Intra-regional loss factors represent the marginal electrical losses associated with transporting electricity to/from a load/generator to the RRN. AEMO calculates intra-regional loss factors, which are fixed for 12 months, for each transmission connection point in every region.
- Inter-regional loss factors represent the marginal electrical losses associated with transporting electricity between RRNs. AEMO estimates equations to approximate losses between regions. The equations are fixed for 12 months. Inter-regional loss factors are calculated for each 5-minute dispatch interval using these equations.

56 Participant bids and offers are adjusted by inter-regional and intra-regional loss factors so that the level of losses is accounted for when determining which generators and dispatchable loads are dispatched.

2.4.4 Regional pricing and settlement

57 As discussed above, the NEM is divided into a number of geographic 'regions', with each NEM jurisdiction presently occupying one such region. The regional structure of the market is a key design feature of the NEM. Regional boundaries were initially established at points where transmission network connections were weak (or non-existent) and, hence, where congestion was greatest and/or more likely.

58 The RRP for each region – otherwise referred to as the relevant 'spot price' in that region – is the price that reflects the marginal value or cost of electricity at the RRN. AEMO's dispatch engine calculates a spot price in respect of every five-minute 'dispatch interval' for every region as a by-product of the dispatch process. The arithmetic average of the six dispatch prices within a thirty-minute 'trading interval' is the spot price used for settlement purposes. The trading interval price, adjusted by static intra-regional loss factors, is the price at which all generators and customers in the region are settled in respect of their wholesale electricity sales and purchases for the relevant trading interval.

59 Due to the characteristics noted in section 2.2.1, spot prices in the NEM can be extremely volatile. Particularly in tight demand-supply balance conditions, the level of spot prices can rapidly increase (or decrease), such as from an average level of about $50/MWh up to $13,100/MWh (or vice versa). In general terms, NEM spot prices tend to be higher during the day than during the night, as daytime electricity demand tends to be significantly higher than overnight

Contents

demand. Likewise, weekday prices tend to be higher than weekend or public holiday prices.

60 Price signals in the NEM help promote efficient dispatch and investment outcomes. For example, if spot prices are very high for short periods of time and relatively low at other times, this will provide a signal for more peaking plant, which are relatively cheap to build and can run economically for only a few hours per year. However, if the spot price remains elevated for larger proportions of the year, this will provide a signal for more baseload or 'mid-merit' plant, which have lower operating costs and, as such, are more economical to run for longer periods of time.

61 The pattern or profile of spot prices depends on a range of factors including:

- The capacity, location and type of existing generators
- The current and expected future level and pattern or profile of electricity demand from end-use customers
- The scope for new generators of different types and cost structures to be developed in different locations in the future.

62 The prevailing and expected profile of spot prices manifests in prices for wholesale derivative instruments. For example, if spot prices are very high for short periods of time and relatively low at other times, this will tend to result in moderate strike prices for 'swap' contracts and high premiums for 'cap' contracts. However, if the spot price remains elevated for larger proportions of the year, this will tend to result in higher strike prices for swap contracts and relatively moderate premiums for cap contracts. The nature, pricing and role of derivative contracts in the NEM is discussed in section 5 below.

63 The key implication of transmission losses and constraints for pricing and settlement within the market is that spot prices will vary on a locational basis. As noted above, the RRP represents the marginal cost (based on bids and offers submitted) of meeting a 1 MW increment of demand at the corresponding RRN. Where constraints and losses arise *between* NEM regions, the relevant RRPs will diverge to reflect the differing marginal cost of electricity in different regions. Generally speaking, electricity will flow across interconnectors from regions with a relatively low RRP to regions with relatively high RRPs, in keeping with the relative marginal value of electricity between the regions. However, this need not always be the case. Where, in addition, constraints and losses arise *within* a region, the RRP will no longer reflect the marginal cost of electricity at each and every location or 'node' within the region.

64 In its 2013 *State of the Energy Market* report, the AER noted that in 2012/13, prices were aligned across the mainland regions of the NEM for 77% of the time, leaving aside the relatively small price impact of transmission losses. This

compared with 70% of the time in 2011/12.[10] These figures indicate that transmission constraints between regions have bound for a small (and shrinking) minority of the time in recent years.

10 AER, *State of the Energy Market 2013*, p.34.

3 Generators in the NEM

3.1 Classes of generator participation

65 Generators in the NEM are classified into one of two market categories and one of three scheduling categories:

- **Market generator**: a generator whose output is at least partly sold through the spot market. Note that market generators may in part be classified as ancillary services generators if they wish to provide and earn revenue for the provision of market ancillary services.
- **Non-market generator**: a generator whose entire output is sold directly to a local retailer or customer outside the spot market.
- **Scheduled generator**: an individual or group of generators with a capacity rating over 30 MW and whose output is scheduled by AEMO.
- **Semi-scheduled generator**: an individual or group of generators with a capacity rating over 30 MW whose output is intermittent (e.g. wind).
- **Non-scheduled generator**: an individual or group of generators with a capacity rating less than 30 MW. Those with a capacity rating of 5-30 MW must register with AEMO.

66 Most large generators in the NEM are market scheduled generators. This means that the output of the power station is sold through the NEM, and AEMO schedules the dispatch of the power station. A small generator (less than 30 MW) may be registered as a non-scheduled generator if its owner does not want it to be dispatched by AEMO. The owner may also register the generator as a non-market generator if its output is purchased in its entirety by a customer located at the same connection point. Semi-scheduled generators are designed to deal with large-scale intermittent plant such as wind.

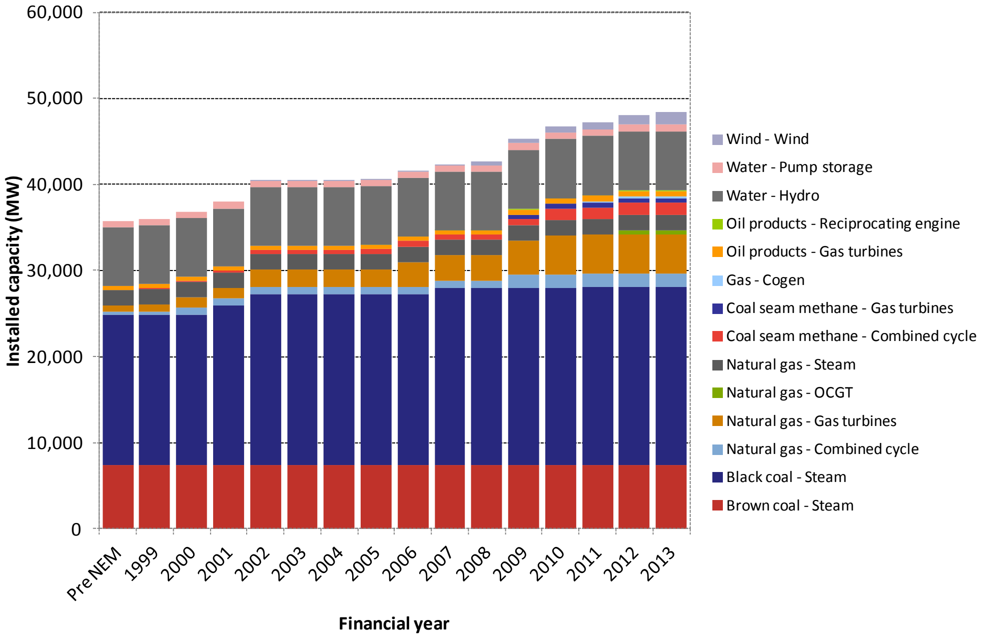
67 This range of classifications is intended to ensure the secure and reliable operation of the power system by allowing AEMO to dispatch all large generators centrally, and to avoid imposing the costs of complying with the NEM arrangements on small generation projects. In many cases, non-market non-scheduled generators are too small to make participation in the NEM (and payment of the necessary fees and compliance costs) economic.

3.2 Generation capacity and output in the NEM

68 Figure 7 shows cumulative installed capacity in the NEM by fuel and technology type for all years since the inception of the NEM. The NEM plant mix is dominated by black and brown coal baseload generation. In more recent years there has been an increase in gas generation particularly in NSW and Queensland.

There has also been an increase in wind generation as a result of the Renewable Energy Target (RET) – see further section 4 below.

Figure 7: Investment in the NEM



Source: Frontier Economics analysis of ESAA data and public reports

69 Table 1 sets out generating capacity by region and fuel type in the NEM for FY2012/13.[11] These capacities are measured at the generator terminal (GT), and include scheduled and semi-scheduled generation[12]. NSW has the largest generating capacity in the NEM, followed by Queensland and Victoria.

70 The majority of NEM generating capacity is coal fired, with hydro and gas also accounting for significant capacity. The same pattern is reflected in generation output in the NEM, with coal fired generation accounting for the majority of output.

71 The pattern of generating capacity by fuel type varies between regions and reflects variations in the availability and cost of fuel. Most generating capacity in NSW is black coal fired (around 70 per cent), with small amounts of hydro, gas and oil fuels. Queensland is similar to NSW in this respect, with black coal

11 These values are based on the average capacity across the financial year. Some generators' capacity may vary between winter and summer. In addition, some generator might notify AEMO of their mothballing/retirement decisions during the course of the financial year.

12 Non-scheduled has been excluded. Non-scheduled generation does not participate in the central dispatch process and it accounts for 6.6% of the total NEM generation installed capacity (*AEMO, Generation Information November 15 2013, 2013*).

accounting for the largest proportion of generating capacity (around 65 per cent), and gas, hydro and oil fuels making up the remainder.

Table 1: Generation capacity in the NEM, by Fuel Type (FY 2012/13, MW GT)

Region	Black Coal	Brown Coal	Gas	Oil	Hydro	Wind	Total
Capacity (MW)							
NSW	11,470	-	2,035	-	2,825	95	16,425
QLD	8,279	-	3,037	453	654	-	12,423
VIC	-	6,648	2,434	-	2,178	378	11,638
SA	-	546	2,747	116	-	817	4,226
TAS	-	-	371	-	2,175	-	2,546
Total	**19,749**	**7,194**	**10,624**	**569**	**7,832**	**1,290**	**47,258**
Share of capacity							
NSW	24.3%	0.0%	4.3%	0.0%	6.0%	0.2%	34.8%
QLD	17.5%	0.0%	6.4%	1.0%	1.4%	0.0%	26.3%
VIC	0.0%	14.1%	5.2%	0.0%	4.6%	0.8%	24.6%
SA	0.0%	1.2%	5.8%	0.2%	0.0%	1.7%	8.9%
TAS	0.0%	0.0%	0.8%	0.0%	4.6%	0.0%	5.4%
Total	**41.8%**	**15.2%**	**22.5%**	**1.2%**	**16.6%**	**2.7%**	**100.0%**

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

72 The predominance of black coal generation in NSW and Queensland reflects the abundant black coal resources in these States. In contrast, Victoria and South Australia are more reliant on brown coal and gas. Brown coal accounts for the majority of generating capacity in Victoria (around 60 per cent). Victoria also has significant gas capacity (around 20 per cent) and hydro accounts for the majority of the remainder. South Australia is heavily reliant on gas fired generation, which accounts for 65 per cent of capacity, supported primarily by brown coal (around 15 per cent). South Australia also has a large amount of installed wind capacity, which accounts for about 20 percent of its total generation capacity. Tasmania relies on hydro generation (around 85 per cent) and gas generation (around 15 per cent).

73 Table 2 shows electricity generated at the generator terminals, by fuel type and region during the 2012/13 financial year. As seen in Table 2, the dominance of black coal and brown coal in the generation mix in the NEM is even more apparent on an energy basis than it is on a capacity basis. Black coal and brown coal accounted for around 52 per cent and 25 per cent, respectively, of total electricity generated. Wind, hydro plant and gas-fired plant accounted for roughly 2 per cent 9 per cent and 12 per cent, respectively, of total electricity generated.

Table 2: Production in the NEM, by fuel type (2012/13, GT)[13]

Region	Black Coal	Brown Coal	Gas	Oil	Hydro	Wind	Total
Energy (GWh)							
NSW	57,212	-	4,238	-	3,228	301	64,979
QLD	43,738	-	9,520	58	748	-	54,064
VIC	-	45,907	2,043	-	3,114	741	51,804
SA	-	2,238	6,768	0	-	2,505	11,511
TAS	-	-	1,695	-	10,236	10	11,941
Total	**100,950**	**48,144**	**24,264**	**58**	**17,336**	**3,556**	**194,299**
Share of output (%)							
NSW	29.4%	-	2.2%	-	1.7%	0.2%	33.4%
QLD	22.5%	-	4.9%	0.0%	0.4%	-	27.8%
VIC	-	23.6%	1.1%	-	1.6%	0.4%	26.7%
SA	-	1.2%	3.5%	0.0%	-	1.3%	5.9%
TAS	-	-	0.9%	-	5.3%	0.0%	6.1%
Total	**52.0%**	**24.8%**	**12.5%**	**0.0%**	**8.9%**	**1.8%**	**100.0%**

Source: Frontier Economics analysis of AEMO data

74 The fact that black coal-fired generation and brown coal-fired generation account for a larger share of energy output than of capacity indicates that these coal-fired

13 Table 1 indicates that there is no wind capacity in Tasmania in FY 2012/13 however Table 2 table indicates positive generation from a Tasmania wind generator in FY 2012/13. This generation comes from Musselroe Wind Farm. It began generating electricity in 2013 however its capacity was not made fully available until 2014, hence no capacity was recorded for Musselroe Wind Farm for the calculation of capacity in Table 1.

generators operate at higher capacity factors[14] than hydro generators and gas-fired generators.

75 Table 3 shows the capacity factors by fuel type and region for the periods from 2008/09 to 2012/13. It is calculated as the ratio of total generator output to the the output of the system if it operated at the average of capacity during this period. Table 4 demonstrates that brown coal generators have the highest capacity factor in the NEM, which is consistent with these generators having the lowest operating costs.

76 The capacity factor of Victorian brown coal-fired generators is around 87 per cent, and the capacity factor of South Australia brown coal-fired generators is around 58 per cent. Black coal-fired generators in NSW and Queensland have the next highest capacity factors, at close to 60 per cent. On average, a gas-fired generators run at a capacity factor of approximately 27 per cent, reflecting the higher cost of gas relative to coal in the NEM. The capacity factor of wind plants across the NEM is around 30 percent, as their output is constrained by the availability of wind. Hydro generators operate at an average capacity factor across the NEM of 21 per cent reflecting the energy constraints associated with limited water resources.

Table 3: Average Capacity factors in the NEM between financial year 2008/09-2012/13, by fuel type

Region	Black Coal	Brown Coal	Gas	Oil	Hydro	Wind	Total
NSW	60.8%	-	23.4%	-	10.6%	37.4%	48.5%
QLD	61.5%	-	40.9%	0.8%	14.1%	-	52.5%
VIC	-	87.2%	7.6%	-	13.9%	25.2%	57.6%
SA	-	58.7%	28.3%	0.2%	-	35.3%	33.9%
TAS	-	-	42.5%	-	43.8%	-	43.6%
NEM	**61.1%**	**84.3%**	**27.0%**	**0.7%**	**21.3%**	**34.3%**	**50.1%**

Source: Frontier Economics analysis based on ESAA, AEMO Generation Information and public reports

3.3 Generator cost structures

77 The varying capacity factors of different types of generators in the NEM can, to a large extent, be explained by differences in their cost structures. Generally

[14] Capacity factor is defined as the ratio of the actual output of a plant over a period of time to the output of the plant over that period of time if the plant had operated at full capacity.

speaking, generators with relatively low operating costs (eg Victorian brown coal generators) tend to have relatively high fixed costs and vice versa (eg gas-fired generators).

78 The key categories of costs relevant to electricity generators include:

- Fixed/capital costs of developing the plant: including acquiring land, obtaining planning approvals, installing turbines and fuel delivery mechanisms and arranging connection to the transmission network
- Fixed operating and maintenance costs (FOM): those costs that need to be incurred periodically regardless of how much power the generator produces.
- Variable operating and maintenance costs (VOM): those costs that need to be incurred periodically and do vary according to how much power the generator produces.
- Fuel and carbon: costs that vary directly with output:
  - Fuel costs – eg coal, gas or oil (nil for most renewable plant like hydro and wind)
  - Carbon price (if any) on fuel used for electricity production – currently $24.15/tonne of carbon dioxide-equivalent; accordingly, this cost varies by the type of fuel used by each generator as well as by the technology of the generator.

79 Example operating (VOM, fuel and carbon) costs estimated for FY2014 for thermal generators participating in the NEM are presented in Table 4, in ascending order of short run operating cost (excluding carbon costs).

Table 4: Example operating costs ($/MWh, real $ FY2014)

Generator	Example generator	VOM	Fuel	Carbon	SRMC (ex. Carbon)	SRMC (inc. Carbon)
Brown Coal	Hazelwood	$1.31	$1.51	$36.87	$2.81	$39.68
Black Coal	Bayswater	$1.31	$14.55	$23.95	$15.86	$39.81
Black Coal	Stanwell	$1.31	$15.26	$22.07	$16.57	$38.64
CCGT	Darling Downs	$1.16	$29.43	$10.07	$30.59	$40.66
OCGT	Uranquinty	$10.98	$85.81	$17.79	$96.79	$114.59

Source: AEMO, 2013 Planning Assumptions, 2013 (accessed 22 March 2014)

80 It is efficient to run generators with:

- high fixed costs and low operating costs for a large proportion of the time

Contents

- low fixed costs and high operating costs for a small proportion of the time.

81 As noted in section 2.4.4 above, the operation of the NEM helps promote the dispatch of and investment in generators in line with efficient outcomes.

3.4 Market structure

82 This section presents market shares for the NEM and NSW across two indicators: installed capacity and annual energy dispatch. These market shares include scheduled and semi-scheduled generation only.[15]

83 The NSW market shares do not account for interconnect capacity or flows. Interconnects have been a significant source of supply to NSW. As discussed in Section 6.4.4, NSW is a net importer of energy and has imported 7,713 GWh annually on average over the last 5 years (this represents an average of 10% of annual NSW energy demand). Including the contribution of interconnects in NSW market share calculations would result in lower levels of concentration in the NSW market.

84 Table 5 and Figure 8 present estimates of the NEM wide market shares of the 10 largest portfolios. Currently Origin, AGL and Energy Australia (EA) are the three largest portfolios and each has a market share of roughly 12%. Figure 8 illustrates how the market shares have evolved over the last 5 years. The key changes to market shares over time involve the restructuring of Queensland generation from three to two portfolios as well as the sale of the NSW state owned generators in 2011.

Table 5: NEM market shares by capacity FY2013

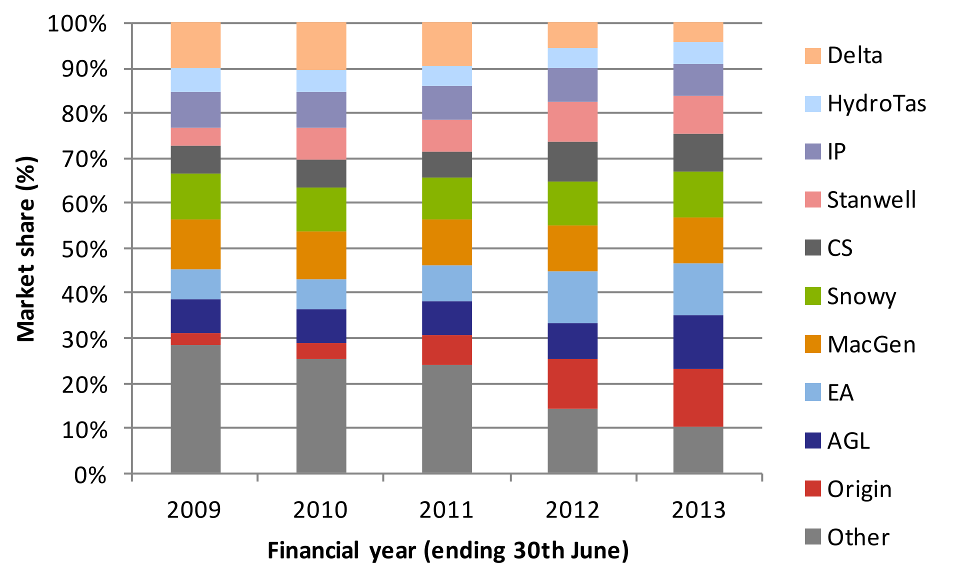
Rank	Portfolio	Market share
1	Origin	12.60%
2	AGL	11.87%
3	EA	11.78%
4	MacGen	10.22%
5	Snowy	9.96%
6	CS	8.63%

15 All market share figures presented in this section include scheduled and semi-scheduled generation only. Exclusion of non-scheduled generation is not material to the market share figures as they are a small share of total NEM generation. Furthermore, the capacity does not participate in the central dispatch process.

7	Stanwell	8.17%
8	IP	7.38%
9	HydroTas	4.60%
10	Delta	4.33%
Other		10.46%
Total		100%

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Figure 8: NEM market shares by capacity FY2009 to FY2013



Source: Frontier Economics analysis based on AEMO Generation Information and public reports

85 Table 6 and Figure 9 present estimates of the capacity based NSW market shares of the 10 largest NSW portfolios. Currently Macquarie Generation, Origin and EA are the three largest portfolios with 29%, 23% and 17% of the NSW market respectively. Figure 9 illustrates how the NSW market shares have evolved over the last 5 years with the most significant change arising from the sale of the NSW state owned generators in 2011.

Table 6: NSW market shares by capacity FY2013

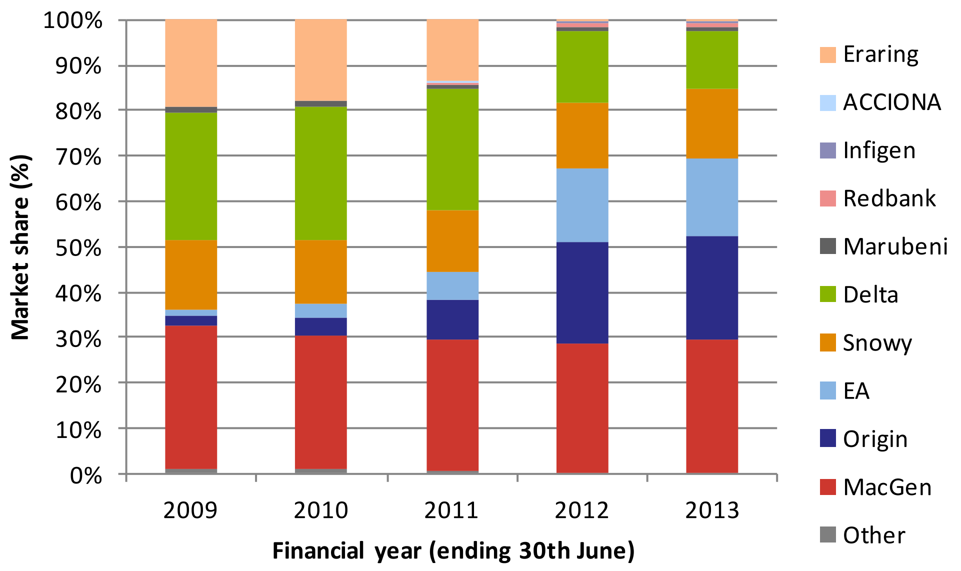
Rank	Portfolio	FY2013
1	MacGen	29.41%

Contents

2	Origin	23.04%
3	EA	16.89%
4	Snowy	15.56%
5	Delta	12.44%
6	Marubeni	0.99%
7	Redbank	0.91%
8	Infigen	0.29%
9	ACCIONA	0.29%
10	Eraring	0.18%
Other		0.00%
Total		100%

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Figure 9: NSW market shares by capacity FY2009 to FY2013



Source: Frontier Economics analysis based on AEMO Generation Information and public reports

86 Table 7 and Figure 10 present estimates of the NEM wide market shares of the 10 largest portfolios based on historical output.

87 In contrast to the capacity based market shares, Energy Australia, Macquarie Generation and International Power (IP) are the three largest portfolios on an output basis reflecting the fact that these portfolios own a large proportion of baseload plant as opposed to intermediate and peaking plant. Figure 10 illustrates how these market shares have evolved over the last 5 years. Similar to Figure 8, the key changes to the market structure over time are a result of the restructuring of Queensland generation portfolios and the sale of the NSW state owned generators in 2011.

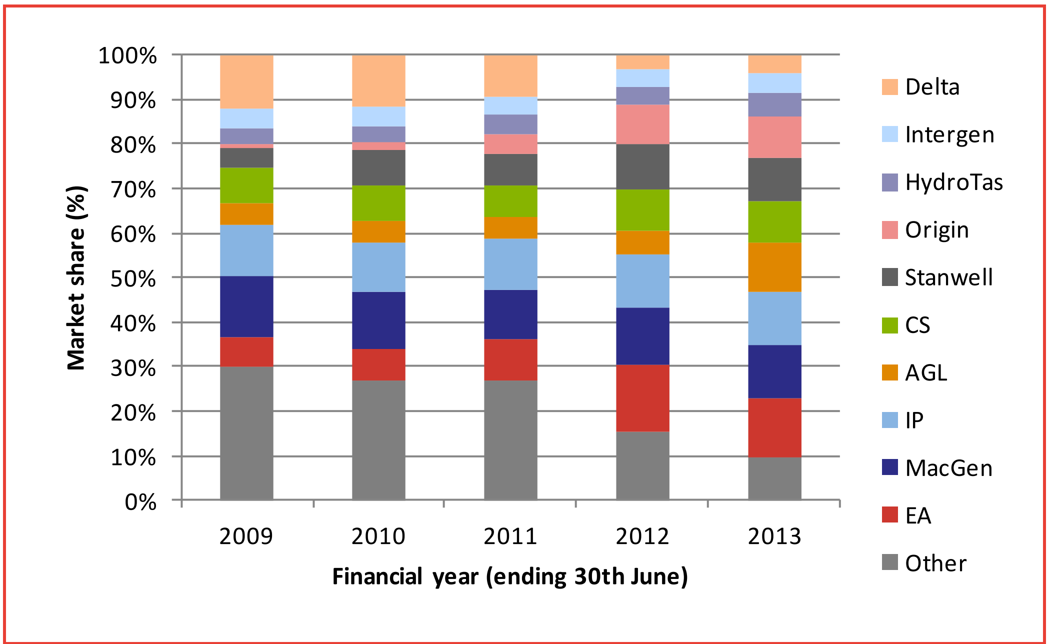
Table 7: NEM market shares by output FY2013

Rank	Portfolio	FY2013
1	EA	13.2%
2	MacGen	12.0%
3	IP	11.8%
4	AGL	11.2%
5	CS	9.5%
6	Stanwell	9.5%
7	Origin	9.4%
8	HydroTas	5.3%
9	Intergen	4.7%
10	Delta	3.9%
Other		9.6%
Total		100%

Source: Frontier Economics analysis of AEMO data

Contents

Figure 10: NEM market shares by output FY2009 to FY2013



Source: Frontier Economics analysis of AEMO data

88 Table 8 and Figure 11 present estimates of the NSW region market shares of the 10 largest NSW portfolios based on historical output.

89 Similar to the capacity based market shares, Macquarie Generation, EA and Origin are the three largest portfolios with 36%, 26% and 19% of the NSW market respectively. Figure 9 illustrates how the NSW market shares have evolved over the last 5 years with the most significant change arising from the sale of the NSW state owned generators in 2011.

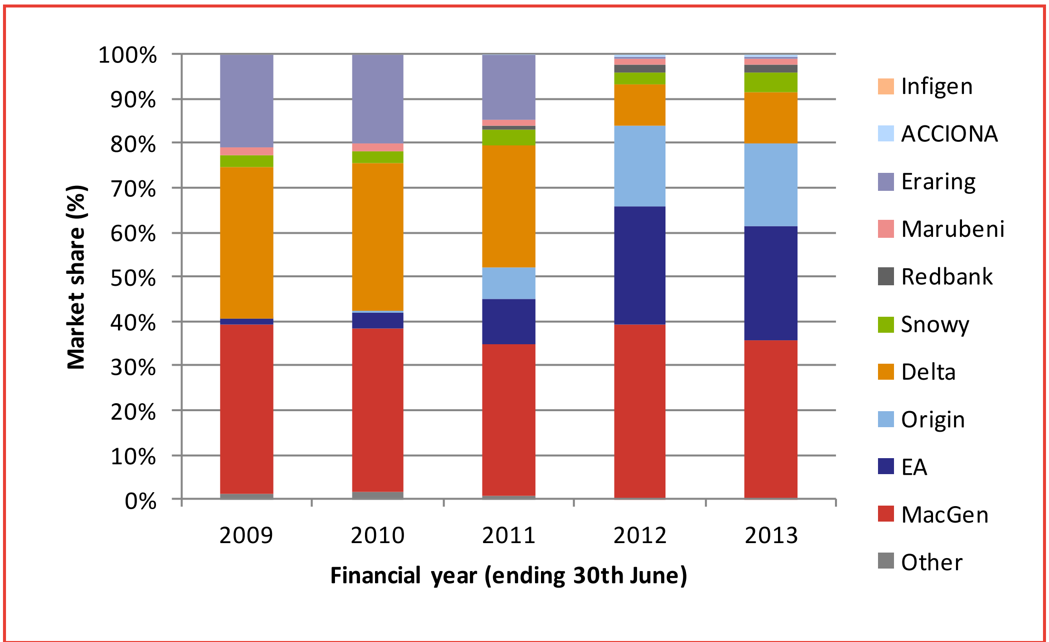
Table 8: NSW market shares by output FY2013

Rank	Portfolio	FY2013
1	MacGen	35.91%
2	EA	25.67%
3	Origin	18.45%
4	Delta	11.62%
5	Snowy	4.37%
6	Redbank	1.65%

7	Marubeni	1.54%
8	Eraring	0.33%
9	ACCIONA	0.24%
10	Infigen	0.22%
Other		0.00%
Total		100%

Source: Frontier Economics analysis of AEMO data

Figure 11: NSW market shares by output FY2009 to FY2013



Source: Frontier Economics analysis of AEMO data

Contents

4 Retailing

4.1 Nature of the activity

90 Retailers are firms responsible for purchasing electricity in the wholesale market on behalf of their customers and billing their customers in respect of the power those customers consume. Retailers:

- purchase electricity through the wholesale exchange operated by AEMO and
- arrange and pay for the provision of network services required to convey power to the premises of their customers.

91 Like generators, electricity retailers are registered participants in the NEM. Retailers are also licensed by the jurisdiction(s) in which they operate.

4.1.1 Types of customers

92 For reasons outlined below, almost all electricity consumers in the NEM purchase their power from retailers. Retailers' customers can be categorised in a number of ways. The most common way to categorise end-use electricity customers is according to 'type', as customer type can be very informative of the level and pattern of customers' electricity consumption.

93 The key categories and sub-categories of end-use electricity customers are:

- Residential customers – tend to consume up to 20 MWh per annum, with relatively 'peaky' consumption patterns (peak consumption tends to be on hot summer afternoons and weekday evenings).
- Commercial customers – consume varying levels of power with relatively flat patterns or profiles of consumption during business hours and low consumption outside of daytime hours.
- Industrial customers – tend to consume large quantities of power with flat consumption patterns that prevail over most days, with relatively small reductions in consumption during overnight periods.

4.1.2 Role of retailers

94 The *raison d'etre* of retailers is to act as an intermediary between individual electricity consumers and the range of parties (generators, AEMO and network service providers) involved in delivering power to those customers. It would be extremely costly (and inefficient) for consumers to have to contract with all these parties themselves in order to be supplied with power. When the electricity supply industry in each State was a vertically-integrated monopoly, there was no need for retailers. For example, Victorian customers used to receive bills directly from the State Electricity Commission of Victoria (SECV), who operated

generators, managed the power system and transported power to consumers' premises.

95 Beyond acting as an intermediary, retailers play a key role in smoothing volatile prices for their customers. As discussed above, wholesale electricity prices in the NEM are designed to reflect the marginal cost of power at different locations in real-time. These prices can be extremely volatile. The benefit of real-time price signals lies principally in promoting the efficient dispatch of generators and in promoting efficient investment in new generation.

96 The highly inelastic demand for electricity, particularly in the short term, combined with the lack of real-time two-way metering at most customers' premises and the desire of most customers to avoid facing highly volatile prices means that retailers generally offer tariffs that do not vary in line with prevailing underlying market demand-supply conditions.

97 In general most retailers' contracts with end-use customers in the NEM provide for linear pricing structures, in that per-unit prices do not generally vary according to the volume of electricity consumed. For example, most residential and small business customers pay a flat tariff (in c/kWh) on their total consumption, or at least a flat tariff in relation to large ranges of consumption. Somewhat larger business customers may pay tariffs that vary by time of day, such as different rates for consumption during 'peak', 'shoulder' and 'off-peak' periods. But in even these cases, rates do not vary according to an individual customer's level of consumption and further, the level and timing of such temporal tariff variations are known in advance. For example, a customer will know that its night time consumption is charged at 15c/kWh while its daytime consumption is charged at 35c/kWh. These differing prices will bear no relationship to prevailing wholesale spot prices.

98 Even in experimental trials of 'critical peak pricing' (or 'CPP') tariffs, designed to encourage high levels of demand responsiveness on high demand days, the very high tariffs applicable during critical peak periods are known in advance by customers. For example, under CPP, customers may receive an email or SMS message one evening alerting them of very high prices applying on the afternoon of the next day. But customers know in advance the rates they will pay on consumption during critical peak periods. CPP rates do not vary with spot prices.

99 Therefore, most retailers are in a position where:

- the prices they receive from their customers are either flat or time-varying on a highly-averaged basis, whereas
- the prices they pay on their customers' consumption can vary dramatically on a half-hourly basis..

100 To manage this divergence between input prices and sales prices, retailers typically enter financial derivative contracts with counterparties (commonly,

Contents

generators), which provide a hedge against volatile spot prices. The two most common types of derivative contracts in the NEM are 'swaps' and 'caps'. Both are settled against regional spot price outcomes. Swaps can be described as 'contracts-for-differences', with a defined strike price and side difference payments depending on whether the spot price is above or below the strike price. Caps can be characterised as call options, whereby the buyer receives a stream of payments that serve to hedge the buyer against spot prices in excess of a specified level (normally $300/MWh) in exchange for an up-front premium. Hedging instruments are discussed in more detail in section 5 below.

101 The cost of hedging spot price volatility forms part of the wholesale energy cost that a retailer faces and ultimately passes on to its customers.

102 The price-smoothing role of retailers combined with the variable demand of end-use customers means that a key task for a retailer is to manage financial risk. This is a far from straightforward problem because retailers' revenues and expenses can vary for different reasons:

- Revenues – retailers will know the tariffs applicable to their customers but will not know how much their customers will consume in real time
- Expenses – retailers can choose to purchase electricity unhedged from the spot market or can choose to hedge their purchases by entering financial contracts of one sort of another or by acquiring generation assets or rights to generators' outputs.

103 The risk management options available to retailers and generators are discussed in section 5 below.

4.2 Retailer obligations and costs

104 Retailers are subject to a range of regulatory obligations. These include:

- Prudential requirements
- Pricing regulations
- Renewable Energy Target obligations

105 These are outlined briefly below.

4.2.1 Prudential and credit support requirements

106 Retailers in the NEM are required to provide financial collateral or guarantees in respect of the energy consumption and network usage of their customers.

107 The Rules require retailers other than those with relatively high credit ratings to provide credit support to AEMO in respect of their wholesale electricity purchases. This credit support is an unconditional guarantee from an acceptable credit support provider, for an amount that reflects the potential exposure of the

market to default by the market participant. Across the NEM at any one time, retailers provide several billion dollars in bank guarantees to meet these obligations. These requirements are designed to maintain the integrity of the wholesale spot market, and provide confidence that generators will be paid for the electricity they supply.

108 We note that 'reallocation arrangements' in the NEM can help to reduce a retailer's weekly cash settlement to AEMO. If structured correctly, these arrangements can help reduce a retailer's working capital requirements and its prudential support requirements under the Rules.

109 In addition, the Rules require retailers other than those with relatively high credit ratings or with low market shares to provide credit support to DNSPs in respect of the network usage of their customers. These requirements are designed to protect DNSPs – and ultimately, end-use customers – from the costs of unpaid network charges in the case of the failure of a retailer.

4.2.2 Pricing regulations

110 Apart from Victoria and recently South Australia, electricity retailers in the NEM are subject to regulations capping retail tariffs to residential and small business customers. Regulated retail tariffs in these other jurisdictions are set by jurisdictional regulators and take account of the level of network tariffs, estimates of energy purchase costs and deemed efficient retail costs and margins. In NSW, the Independent Pricing and Regulatory Tribunal (IPART) presently sets maximum retail tariffs for small customers (those consuming up to 160 MWh per annum).

4.2.3 Renewable Energy Target obligations

111 In 2009, the Federal Government legislated the Expanded Renewable Energy Target (RET), which was designed to ensure that 20 per cent of Australia's electricity supply will come from renewable sources by 2020 (about 45,000 GWh). The RET obliged 'liable entities' (mainly retailers) to acquire a certain volume of Renewable Energy Certificates (RECs) based on the size of their energy purchases. RECs could be produced by renewable forms of generation. However, the mass installation of domestic solar PV units induced by state schemes led to a collapse in the REC price, discouraging investment in wind and other larger-scale renewable plant. This led the government to replace the RET with a dual set of policies: the Large Scale Renewable Energy Target (LRET) and the Small Scale Renewable Energy Scheme (SRES).[16] 'RECs' is now an umbrella

[16] See the website of the Department of Climate Change and Energy Efficiency at: http://www.climatechange.gov.au/government/initiatives/renewable-target.aspx

term covering Small-scale Technology Certificates (STCs) and Large-scale Generation Certificates (LGCs).

112 The LRET creates a financial incentive for the establishment and growth of large-scale renewable energy power stations, such as wind and solar farms, or hydro-electric power stations. It does this by legislating demand for LGCs. These LGCs are created based on the amount of eligible renewable electricity produced by the power stations. LGCs can be sold or traded to liable to entities, in addition to the power station's sale of electricity to the grid. RET Liable entities have a legal obligation to buy LGCs and surrender them to the Clean Energy Regulator on an annual basis.

113 The SRES provides households, small business and community groups $40 for each STC created by small-scale technologies like solar panels and solar water heaters.

4.3 Market structure

114 The NSW retail market is comprised of three large players – Origin, EnergyAustralia and AGL – supplemented by a range of smaller competitors, who are also active in other jurisdictions. Estimated market shares for small retail customers are set out in Table 9.

Table 9: NSW Retail market shares (August 2013)

Portfolio	Market Share
Origin	40%
AGL	24%
EA	32%
Lumo	1%
Red	1%
ActewAGL	1%
Other	1%
Total	100%

Source: Frontier Economics' analysis of Figure 5.1 in AER State of the Market 2013, p.122.

115 The willingness of small retail customers in NSW to switch retailer has increased in recent years, as show in Table 10.

Table 10: NSW customer switching of energy retailers, as a percentage of small customers

Year	Annual switches (% of customers)
2008-09	11%
2009-10	13%
2010-11	16%
2011-12	22%
2012-13	26%

Source: Frontier Economics' analysis of Figure 5.3, AER State of the Market 2013, p.128.,

5 Risk management in the NEM

5.1 Financial risk exposures

116 Generators and retailers operating in the NEM are exposed to a wide range of risks. The discussion in this section focuses on the risks that arise in the wholesale sale and purchase of electricity between generators and retailers.

117 Fundamentally, in the NEM:

- Generators are exposed to uncertainty about the volume of electricity they have available to sell ('volume risk') and the price they will receive for that electricity ('price risk');
- Retailers are exposed to uncertainty about the volume of electricity they need to purchase to supply their customers and the price they need to pay for that electricity.

5.1.1 Volume risk

118 Generators and retailers do not know in advance how much electricity they have available or to sell or need to buy, respectively, in the future.

119 For generators, volume uncertainty arises because the nature of generating plant is that its operating reliability is less than 100%. A thermal generator is typically comprised of a number of separate physical 'units' and at any given time, one or more unit(s) may fail, reducing the output of the unit and the power station. This physical risk means that generators tend to be reluctant to enter binding commitments to sell their entire potential output.

120 For retailers, volume uncertainty arises because retailers do not know exactly how much electricity their customers will consume for any given half-hour in the future. The result is that retailers are unaware in advance of how much wholesale electricity they will be responsible for paying for in respect of their customers' consumption. For example, on a particularly hot or cold day, end-use customers will usually consume more electricity than on a mild day. While retailers may have some warning of weather conditions and hence the likelihood of these high levels of consumption, they will not know the exact level of wholesale electricity they will be required to purchase. This will be the case to some extent on any day.

5.1.2 Price risk

121 Due to the compulsory nature of the NEM, both sellers and buyers of electricity in the wholesale market are potentially exposed to spot price volatility.

122 These exposures arise because:

- Generators produce electricity for which they are paid the applicable wholesale spot price. In this sense, generators are naturally 'long' electricity because they gain if the spot price rises. Other things being equal, a generator will be longer at a given point in time the higher its output.
- Retailers purchase electricity for which they must pay the applicable wholesale spot price. In this sense, retailers and large customers are naturally 'short' electricity because they gain if the spot price falls. Other things being equal, a retailer will be shorter at a given point in time the higher its customers' consumption.

123 Moreover, both generators and retailers/large customers have cashflow rights or obligations that are relatively invariant to spot price outcomes. For example, generators have made capital-intensive investments that are often largely funded by debt, which imposes fairly stable interest payment obligations. As noted in section 4, retailers generally supply their customers at prices that do not vary with spot prices (or at all).

5.1.3 Options for managing financial risks

124 NEM participants' varying long and short exposures to spot prices can be managed in two key ways:

- Vertical integration between electricity generation and retailing activities, which represents a form of physical hedging of spot price risk. Vertical integration can take different forms, including the acquisition of physical generation assets or the acquisition of rights to the operation and wholesale proceeds of generators' outputs. As discussed in section 6, many market participants have become vertically integrated in some form to some extent in recent years.

- Purchase or sale of financial derivative contracts.

125 The next section discusses the nature and operation of derivative contracts. The following section, section 5.3, outlines vertical integration risk management options. Participants commonly combine different forms of risk management in different ways at different times.

5.2 Derivative contracts

5.2.1 Types of contracts

126 The two main forms of derivative contract utilised in the NEM are swaps and caps. Options written on these two contracts (swaptions and captions) are also fairly common. More exotic contracts (such as collars and other options) are available but less common.

Swap contracts

127 Swap contracts are broadly defined as a series of financial forward contracts between two parties, whereby one stream of cash flows is 'swapped' for another stream of cash flows at regular intervals over the term of the contract. Typically, swaps involve the swapping of a variable stream of cash flows based on (variable) spot prices with a fixed stream of cash flows based on an agreed strike price. Given that swaps are a form of forward contract, each party to the swap has an *obligation* to exchange the agreed cash flows on the settlement date.

128 A typical swap contract requires the seller of the swap (most often a generator) to pay the buyer (most often a retailer or large industrial customer) the difference between the spot price (variable) and a contract strike price (fixed). This value is positive when the spot price is greater than the strike price, and negative (i.e. the seller receives payment from the buyer) when the spot price is less than the strike price.

129 For example, assume a generator (*G*) and retailer (*R*) enter into a swap contract at a strike price of $25/MWh. This contract implies that at each settlement interval:

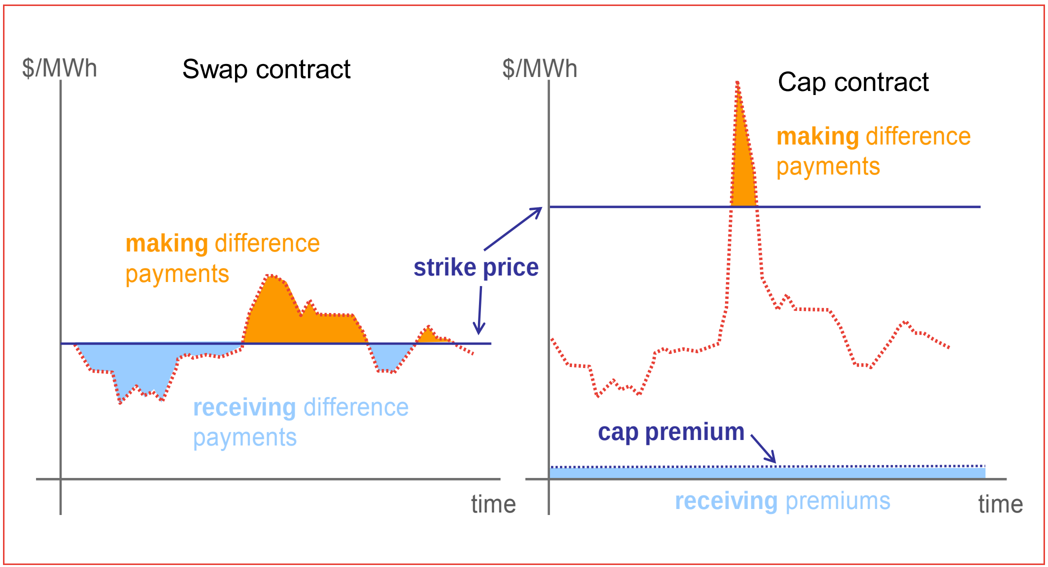
- G will pay R the difference between the spot price of electricity and the strike price of the contract if the spot price is greater than the $25/MWh strike price
- R will pay G the difference between the strike price of the contract and the spot price of electricity, if the spot price is less than the $25/MWh strike price.

Under such an agreement, both the retailer and generator have certainty regarding the ultimate net price they will either pay or receive per unit of energy covered by the contract.

130 The difference payments made and received by the seller of a swap are outlined stylistically in the left pane of Figure 12. During half-hours when the spot price (red line) is above the strike price of the swap (dark blue line) the seller of the swap makes difference payments to the buyer. During half-hours when the spot price is below the strike price the seller receives difference payments from the buyer. The swap contract results in a fixed price (the strike price) for both the seller and buyer for a given level of coverage (determined by the size of the contract).

131 Swap contracts thereby allow parties exposed to the spot price to effectively 'lock in' a fixed price, called the strike price of the contract, and thereby reduce cash flow uncertainty.

Figure 12: Swap and cap contract payoffs



Source: Frontier Economics

132 The strike price struck under a swap contract is based on an expectation of future spot prices. Most swap contracts trade at a modest premium to spot prices. This positive premium indicates that participants in the contract markets face asymmetric risk: there is greater potential for spot prices to rise well above contract strike prices than there is for prices to fall well below strike prices.

Cap contracts

133 A cap contract is a 'one-sided' swap contract which involves the buyer (usually a retailer or large industrial customer) receiving difference payments from the seller (usually a generator) when the spot price exceeds a certain level (the cap strike price) - however at all other times no difference payments are made. The difference payments made to the buyer are equal to the difference between the spot price and the cap strike price. To acquire this protection the buyer of the cap pays the seller a fixed cap premium in every half-hour of the contract. Cap

contracts are typically utilised by electricity retailers to hedge infrequent but extremely costly spot price spikes (when the price can increase up to the MPC of $13,100/MWh in the space of a dispatch interval).

134 The difference payments made and premiums received by the seller of a cap contract are outlined stylistically in the right pane of Figure 12. When the spot price (red line) exceeds the cap contract strike price (dark blue line) the seller of the cap makes difference payments to the buyer, while at all other prices no difference payments are made. In exchange for this spot price protection the buyer of the cap pays the seller a fixed cap premium during every half-hour of the contract.

Hybrid instruments

135 Options contracts covering both swaps ('swaptions') and caps ('captions') are also traded fairly regularly. These contracts give the buyer the right, but not obligation, to enter either a swap or cap as either a buyer or seller on a future date at a pre-determined strike price. To acquire this option, the buyer pays the seller an option premium for every half-hour covered by the underlying swap or cap contract. At the expiration of the option the buyer chooses whether to exercise the option or not. If the buyer chooses to exercise, then the buyer and seller become counterparties in the underlying swap or cap contract. If the buyer chooses not exercise, then the underlying swap or cap contract lapses.

136 An 'Asian option' is an option where payment is calculated based on the difference between the strike price and the average spot price over an agreed period.[17]

Structured and 'exotic' instruments

137 Derivative contracts are purely financial arrangements and are not subject to any physical constraints. As a result, they can be structured in many different ways to meet the risk management requirements of market participants. Examples of structured contracts include 'shaped' or 'load following' swaps or caps.

138 Under a standard swap, the parties agree on a strike price for a specified volume of electricity over a defined period. A shaped contract allows a retailer to tailor the swap so that the agreed volumes vary at different times of the day to reflect the shape of its exposure, for example the forecast customer demand. A load following swap is even more tailored to the retailer's customers' demand and will follow the actual usage of the retailer's customers over the agreed period. These types of contracts allow the retailer to better manage volume risk, as well as price risk.[18]

---

17 See AEMC, *NEM financial market resilience, Issues Paper*, 8 June 2012, p.10.

18 AEMC, *NEM financial market resilience, Issues Paper*, 8 June 2012, pp.10-11.

139 Other exotic instruments, such as 'weather derivatives' also exist and have been used in the NEM. An example of a weather derivative is a contract that is settled against a particular weather index, such as heating/cool degree days, maximum/minimum temperatures or precipitation over a period of time.[19]

5.2.2 Sources of contracts

140 A variety of derivative contracts are available in the NEM, as either over-the-counter (OTC) instruments entered into between counterparties or as exchange-traded instruments traded on the Australian Securities Exchange (ASX).

141 OTC contracts involve customised bilateral commitments between two parties (generally retailers and generators). OTC contracts can either be directly negotiated (i.e. no financial intermediary between contracting parties) or transacted through a broker. OTC instruments tend to exhibit the following characteristics:

- Highly customised to suit the needs of the two contracting parties
- Non-transparent due to private negotiations and settlement
- Subject to credit default risk in the event a counterparty defaults on its obligations.

142 Exchange-traded instruments involve standardised contracts that are bought and sold through a securities exchange. In Australia, exchange-traded electricity contracts are designed and developed by d-cyphaTrade[20] and sold through the ASX.[21] Exchange-traded contracts tend to exhibit the following characteristics:

- Highly standardised in terms of contract type, size, price fluctuations (ticks) and settlement
- Transparent and publicly reported (aggregated volumes, prices etc)
- Not subject to credit default risk due to the presence of a financial intermediary (clearing house) between contracting parties.

143 Initially, most financial derivatives were OTC instruments. However, since 2006/07, the volume of exchange-traded instruments has grown substantially (Figure 13).

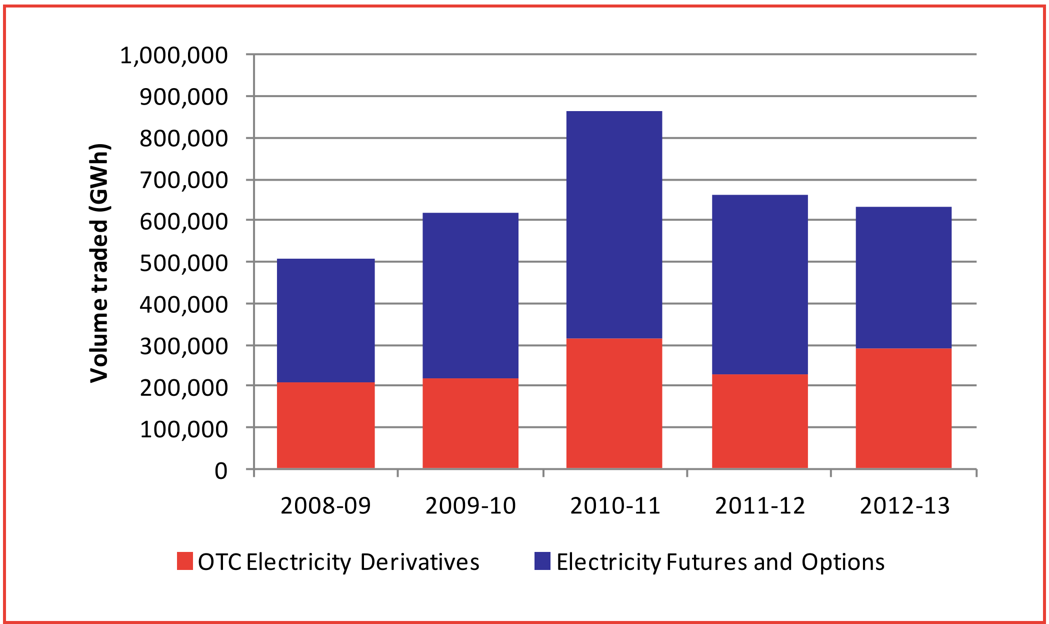
Figure 13: OTC versus exchange-traded market volumes, year on year

---

19 See, for example, Australian Financial Markets Association, *Weather Risk Management*, brochure (2002).

20 www.d-cyphatrade.com.au

21 The SFE merged with the Australian Stock Exchange in 2006 and the combined entity now operates under the name of Australian Securities Exchange.



Source: AFMA Financial Markets Report 2013[22]

5.2.3 Use of derivatives by NEM participants

144 Financial derivatives are traded by both NEM participants and by non-participant speculators. This section focuses on participant trading of derivatives.

145 NEM participants generally enter derivative contracts to hedge their natural spot price exposures, rather than to extend their natural exposures. Accordingly:

- Since generators have a natural long exposure to the spot price, generators generally sell derivative contracts to hedge or offset their natural exposure.
- Likewise, since retailers and large industrial customers have a natural short exposure to the spot price, these parties typically purchase derivative contracts to offset their natural exposure.

146 Because of the volume risk both generators and retailers face, neither are able to completely eliminate their spot price exposures. For example, a retailer may hedge the expected volume of its customers' electricity consumption for a given half-hour, but its customers' actual consumption in that half-hour may be higher or lower than this expectation. Similarly, a generator may hedge a certain proportion of its expected electricity output for a given half-hour by selling derivative contracts, but its actual output may be more or less. In most cases, due to the tendency of generators to hedge less than their expected output to self-

---

22 OTC contract data is taken from AFMA's 2013 Financial Market Report: https://www.afma.com.au/afmawr/_assets/main/lib90013/2013%20afmr.pdf (accessed 22 March 2014). No central repository for OTC contract data exists. AFMA data is based on respondent surveys, and whilst AFMA note that their surveys are detailed and thorough, OTC volumes and breakdowns should be taken as indicative only.

manage the risk of plant and unit failures or unplanned outages, generators will remain long even if they would prefer not to be.

5.2.4 Hedging inter-regional trade

147 Participants frequently seek to enter derivative contracts with counterparties located in different NEM regions. While this has and does occur, it can create complications not present when trading derivatives settled at the same RRP. These complications stem from the risk that RRPs in the respective regions could diverge, giving rise to basis risk.

Interconnector capacity limits

148 Figure 14 presents the notional interconnect limits of the NEM's interconnects. It should be noted that the real time limits of these interconnects are dynamic and can change as a result of other factors such as generation and load levels.

Figure 14: Notional interconnect limits

From region	To region	Summer peak [MW]	Summer off-peak [MW]	Winter peak [MW]	Winter off-peak [MW]
Queensland [1]	New South Wales	1078	1078	1078	1078
New South Wales	Queensland	400	550	400	550
New South Wales	Victoria	1300	1300	1300	1300
Victoria	New South Wales	1500	1500	1500	1500
Victoria	South Australia	460	460	460	460
South Australia	Victoria	460	460	460	460
Murraylink Vic	South Australia	220	220	220	220
Murraylink SA	Victoria	175	175	175	175
Terranora Interconnector Qld	NSW	220	220	220	220
Terranora Interconnector NSW	Qld	122	122	122	122
* Basslink VIC	Tasmania	478	478	478	478
* Basslink TAS	Victoria	594	594	594	594

Source: AEMO, Interconnector performance: Quarter September-November 2013, 2013

Origin of basis risk

149 Basis risk refers to the risk that the price of a commodity one buys or sells in the physical market moves differently to the price of the same commodity one is hedged against under a financial derivatives contract.

150 Standard derivative contracts can be used for hedging spot price volatility when all counter-parties are settled at the same RRP at which the relevant contract is settled. For example, if both parties were located in the NSW region of the NEM and the swap they entered was also referenced to the NSW RRP, both parties should be hedged from volatility in the NSW price (except for fixed intra-

regional losses). However, participants can be subject to basis risk in the NEM when:

- they have entered into financial contracts with participants located in other region(s)
- transmission limits that restrict flows on interconnectors between those regions bind, causing the relevant RRPs to diverge.

Hedging basis risk in the NEM

151 Participants in the NEM can manage basis risk from entering into inter-regional derivative contracts in several ways.

152 First, participants can acquire inter-regional settlement residue (IRSR) units. IRSR units provide their holder with a stream of payments that is based on the flow on a particular interconnector multiplied by the price difference between the relevant RRPs. These payments are funded by the NEM settlements process, whereby generators in exporting regions are typically paid a lower price than consumers in exporting regions. Given that electricity usually flows from regions with low RRPs to regions with higher RRPs, the result is a positive amount of 'settlements residue' that can be used to hedge inter-regional price differences. IRSR units are made available to participants through quarterly auctions run by AEMO.

153 One limitation of IRSR units is that they do not always provide a reliable or 'firm' hedge against divergences in RRPs. Non-firmness can arise when, for a variety of reasons, the flow on an interconnector is below its nominal expected level despite the fact that the relevant RRPs have separated. Participants sometimes respond to IRSR non-firmness by acquiring a greater MW quantity of IRSR units than their inter-regional MW exposure.

154 Another means of hedging basis risk is for generators to acquire or develop plant, or to contract with other plant, in the counterparty's region. This effectively eliminates the inter-regional aspect of the trade and with it, the generator's basis risk exposure.

5.3 Vertical integration

155 Vertical integration is the second key approach used by market participants in the NEM to hedge their exposures to volatile wholesale spot prices. Unlike derivative contracts – which provide a financial hedge via settlement against a nominated price series or index – vertical integration provides a hedge through any of the following:

- Acquisition of existing generation or retail assets – commonly through a merger or government sales process.

- Establishment or development of new generation or retail assets or activities.
- Acquisition of rights to the outputs or cashflows of generation or retail activities. For example, retailers and large electricity consumers sometimes enter Power Purchase Agreements (PPAs) with generators, which entitle the buyer to either the physical power supply or the spot market proceeds from the electricity output of the subject generating plant.

156 The rationale for vertical integration from a risk management perspective is similar to the rationale for entering derivative contracts: participants seeking to gain offsetting exposure to the pool price from their 'natural' position (for generators being naturally long, for retailers being naturally short).

157 A key attraction of vertical integration is that it helps to avoid or reduce the transaction costs associated with a generator or retailer/large customer needing to negotiate or trade derivative contracts on a regular basis to hedge its spot price exposures. Such transactions costs can include:

- Operating and maintaining a significant trading team
- Meeting additional prudential requirements or providing additional credit support
- Potentially paying higher prices for hedging to due to significant counterparties or potential counterparties 'holding-up' contract (re)negotiations.

158 Another advantage of vertical integration is the role that it can play in supplementing contractual arrangements in managing wholesale spot price risks. Because of their exposures to volume risk, generators and retailers have to manage the risk that they are under- or over-hedged at any particular period of time. *Under-hedging* is particularly problematic for retailers, given the combination of fixed retail prices and volatile spot prices, and difficulties in predicting the shape of retail loads. *Over-hedging* is more of a concern for generators given the costs they face through unfunded difference payments in the event of not being dispatched.

159 The costs associated with taking hedging positions that are subsequently revealed to be sub-optimal define *load shape risk*. Load shape risks can be managed by undertaking further hedging positions, though this will typically be costly and these costs will be explicit.

160 An alternative way of managing volume risks is through vertical integration. The advantage of vertical integration from a risk management perspective is that it converts an explicit risk into an implicit risk; or put another way, it can convert the risk of having to make or face a substantial cash outflow into the risk of bearing an opportunity cost. For example, a retailer that is under-hedged at certain peak demand times and remains short electricity may need to pay a high wholesale spot price in respect of its unhedged electricity purchases. Such a

retailer could respond by over-hedging (purchasing too many derivative contracts), but this would require it to pay the generator if the actual spot price was below the contract strike price. Conversely, if such a retailer acquired a generator with an output capacity well above the retailer's expected peak load, the combined retailer-generator ('gentailer') would not need to make any payments in respect of being effectively long generation. Rather, the gentailer would incur on ongoing opportunity cost from being long generation, except to the extent that it resold its expected long exposure to other parties through financial contracts. Despite their economic equivalence, many investors and market commentators adopt different attitudes to cash outflow costs and opportunity costs.

161 Vertical integration can influence bidding behaviour in a way that is similar to the influence exerted by hedging. This is because retail prices tend to be sticky in the medium term, in part because they are subject to explicit regulation, but also because offering fixed prices to consumers over the medium term is a key part of retailers' commercial strategies. The sticky nature of retail prices means that an integrated entity will need to consider the effects of higher wholesale prices on its retail business. Empirical evidence confirms the moderating impact of vertical integration on bidding behaviour.[23]

162 Evidence on the efficiency benefits and trends towards vertical integration in electricity markets around the world is discussed in section 6 below.

---

23 See James. B. Bushnell, Erin. T Mansur, and Celeste Saravia (2007, "Vertical arrangements, market structure and competition: An analysis of restructured US electricity markets", *American Economic Review*, Vol. 98.1, pp 237-266

6 Critical trends in the NEM

163 While the basic structure and operation of the NEM wholesale price setting arrangement has remained fairly constant over time many other aspects of the NEM have changed significantly, particularly in recent years. In this section some of the more recent changes are described and the effect of these changes on competition in the wholesale market generally and the proposed merger more specifically discussed.

164 Perhaps the two most important developments in the NEM in recent years have been the growing level of oversupply of generation capacity and rising retail electricity prices. In this section I briefly explore these trends and their underlying causes. I also describe other important trends such as the level and movement in wholesale prices and the decline in the amount of transmission constraints between NEM regions in recent years.

6.1 Oversupply

6.1.1 Recent developments in electricity demand and supply

165 Figure 7 in Section 3.2 showed the type and quantity of investment in new generation plant since the commencement of NEM. As discussed in Section 6.2 below, this new investment has in recent years been dominated by the development of new wind generators. This has implications for the conditions faced by thermal generators such as Macquarie Generation, irrespective of its ownership.

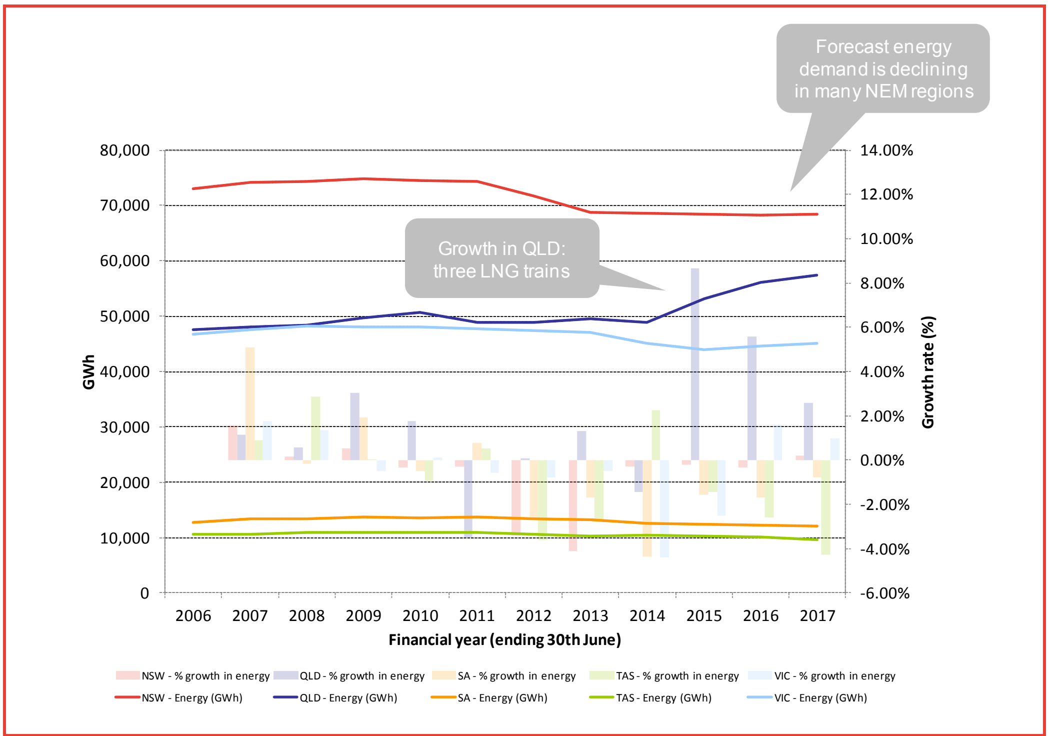
166 At the same time as investment in large-scale renewable plant has proceeded apace, electricity demand across the NEM has declined in recent years. While making a precise attribution of the cause for this decline in demand is not possible, it has generally been caused by a combination of factors, including:

- Closure of large scale energy intensive industries – for example, the Kurri Kurri aluminium smelter (one of the top 10 electricity loads in Australia at the time it closed);
- Consumer response to very large increases in electricity prices largely caused by significant increases in regulated electricity network prices, exacerbated by price increases due to the operation of various environmental policies such as the Renewable Energy Target scheme, state based energy efficiency scheme, solar subsidy schemes and the carbon tax.
- The operation of domestic and commercial solar subsidy schemes has reduced the demand for power generation from the centralised generation system.

167 Furthermore, demand growth is expected to be subdued for the foreseeable future. AEMO forecasts electricity consumption, which it publishes annually. AEMO produces forecast for a range of economic conditions. Figure 15 shows AEMO's low growth energy consumption forecasts along with recent historic consumption levels. This low growth forecast is more consistent with historical consumption levels than AEMO's other scenarios (presented below). Using this low forecast, it is clear that AEMO expects demand to remain flat for at least the next four years. Even if AEMO's less plausible high growth forecast is considered (see Figure 16) annual electricity consumption is not expected to reach its previous peak (achieved in around 2008) for many years to come.

168 AEMO has similar expectations about peak demand. Figure 17 shows the recent historical performance of peak demand by region and AEMO's more likely low growth forecasts. It is clear from Figure 17 that AEMO does not expect peak demand to come close to the historical peaks for many years. Only in AEMO's less plausible high growth case does the forecast peak demand exceed historical peak demand (see Figure 18).

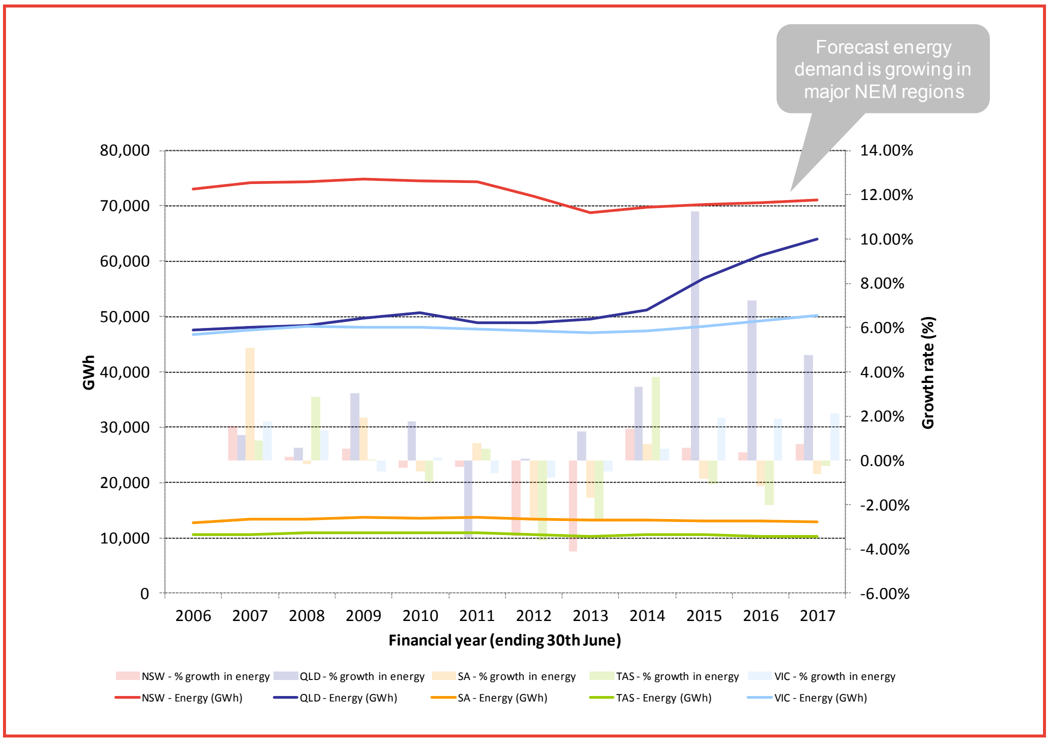
Figure 15: AEMO 2013 NTNDP Scenario 6 Energy Consumption (Low Growth)



Source: AEMO, National Electricity Forecasting Report 2013

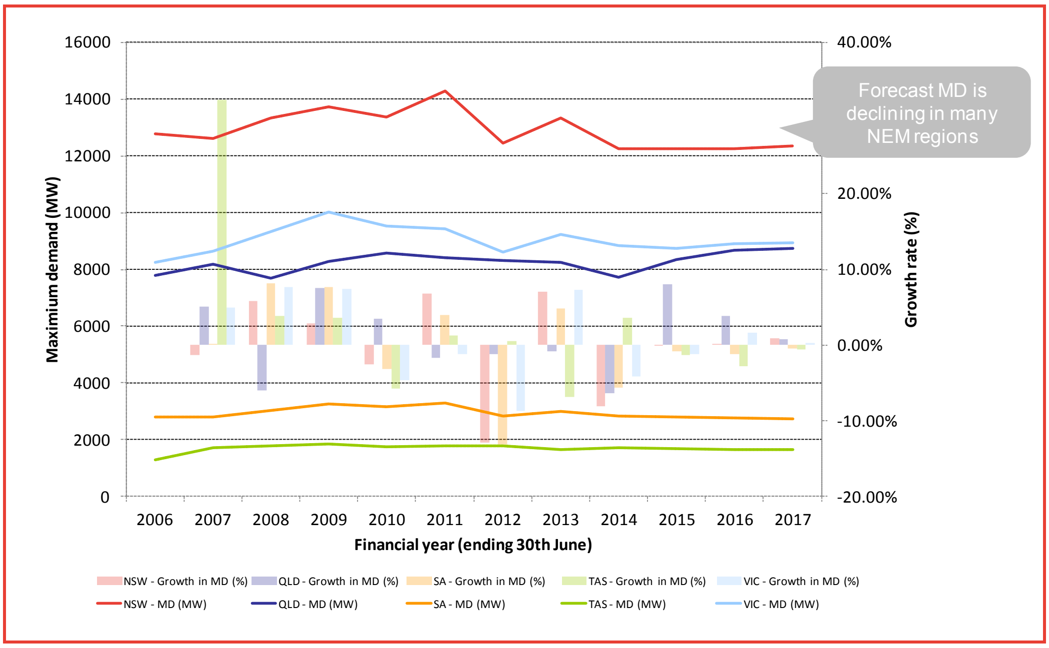
Contents

Figure 16: AEMO 2013 NTNDP Scenario 2 Energy Consumption (High Growth)



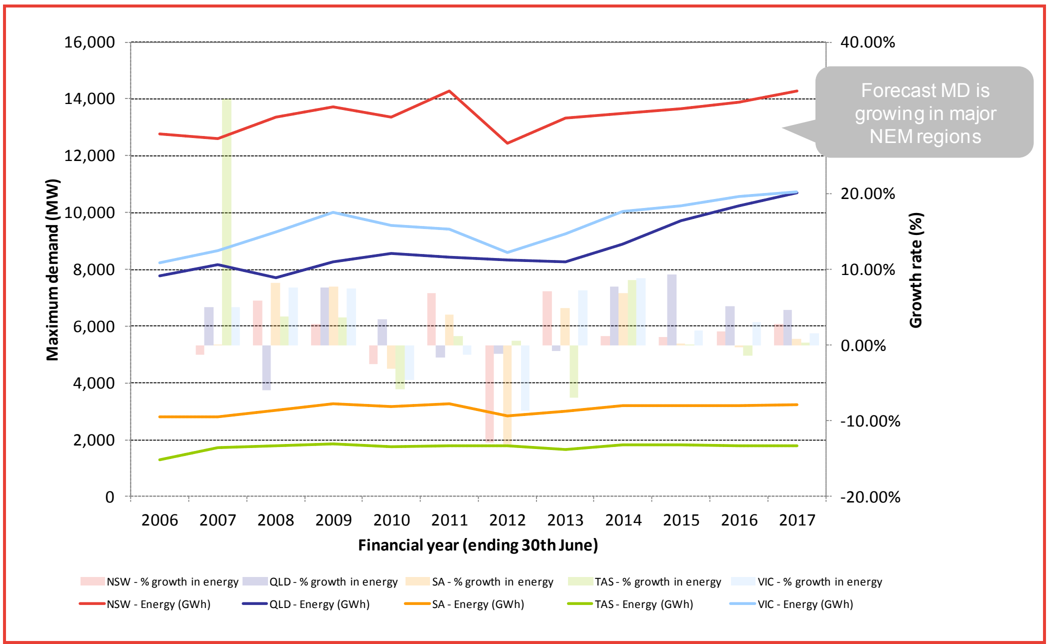
Source: AEMO, National Electricity Forecasting Report 2013

Figure 17: AEMO 2013 NTNDP Scenario 6 Peak Demand (Low Growth)



Source: AEMO, National Electricity Forecasting Report 2013

Figure 18: AEMO 2013 NTNDP Scenario 2 Peak Demand (High Growth)



Source: AEMO, National Electricity Forecasting Report 2013

6.1.2 Role and extent of reserve plant margin

169 Every electric power system requires some level of spare generation capacity (as distinct from *excess* capacity). This spare capacity is required to provide supply reliability as electric generating plants suffer unplanned outages and also need to be remove from generating service to undergo maintenance. On average, the major generating plants in the NEM could expect to be unavailable to generate for any reason for about 10%-15% of the year.

170 To ensure a high level of electricity supply reliability it is important to ensure that plant outages can be met with the operation of spare generation capacity. There are many factors that influence the optimal level of generating plant reserves. For example, the size of the generating units in the power system has an important bearing on how much spare capacity is required - with bigger generating units, proportionally more reserves are required to maintain reliable supply as the spare capacity has to account for the outage of the single largest generating unit. The age of the plants is also important as older generating units fail more often and need more maintenance and this increases the risk of multiple, simultaneous plant failures. The reliability of the transmission system must also be considered as more generators are required to be distributed over a wider geographic area if the transmission system is unreliable.

171 Excess capacity refers to the capacity that is in excess of the spare capacity that is needed to reliably account for plant outages. The presence of spare and excess capacity has a major bearing on the level of competition and prices in the market. If there is too little spare capacity then this increases the opportunity for any one

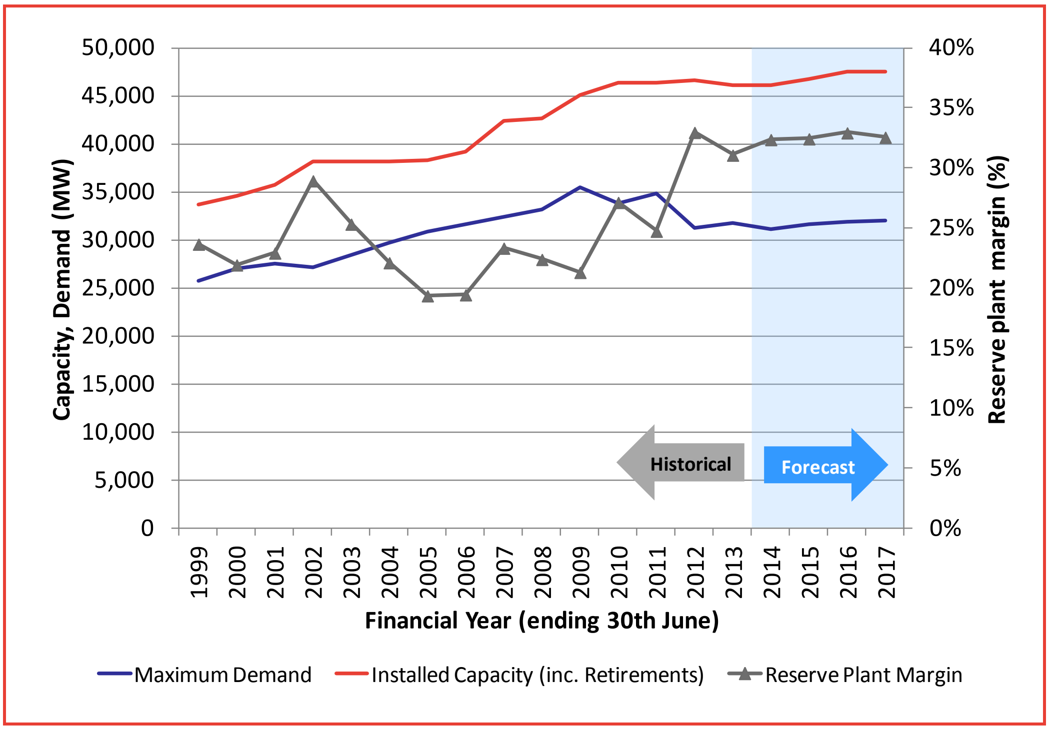
generator to raise wholesale prices as, in the short to medium term, there are few alternatives to consuming electricity – it is for this reason that electricity demand is regarded as being price inelastic in the short to medium. Conversely, and in general, where there is a significant quantity of excess generation capacity the opportunity for any generator to increase the price is lower. A relatively simple way to think about this is if there is more capacity available in the market than the single largest generator then it is very difficult for any one generator to raise the price above their costs. This is because if the largest generator, and certainly all smaller generators, withdrew their capacity in order to drive up prices to profit from inelastic electricity demand, then other generators could fully meet this demand. That is, aside from any opportunity to co-ordinate in some way between generators, in this oversupplied market, no generator has market power and prices will closely reflect costs.

172 The extent of excess capacity is measured by the difference between the supply of generating capacity (in power terms - megawatts) and the demand (in megawatts, for the generation services of scheduled generators in the NEM). Excess capacity occurs either because supply has increased or demand has fallen, or both. In the NEM in recent years both have occurred. This combination of falling demand and rising supply has resulted in the highest level of generating reserves since the commencement of the NEM in 1998.

173 Figure 19 shows the change in Reserve Plant Margin (RPM) since the commencement of the NEM and until 2017. The Reserve Plant Margin is the standard method by which spare and/or excess capacity is measured in a power system. It measures how much capacity is in excess of peak demand in a year, expressed as a percentage. The higher the RPM, the greater the excess capacity, the more competitive the market.

174 It is clear from Figure 19 that the RPM is now higher than when the NEM commenced in 1998. This RPM is forecast to remain at this level over the next few years, where this forecast is based on AEMO's forecasts of demand and reported committed supply investments.

Figure 19: Rising quantity of spare plant in the NEM



Source: Frontier Economics analysis ESAA and AEMO data and information from public reports. [24]

6.2 Growth of wind and renewable generation

175 As noted above, new investment in the NEM has in recent years been dominated by the development of new wind generators. These plants are financially supported by the operation of the RET, which is briefly described in Section 4.2.3.

176 As already indicated, the level of installed scheduled and semi-scheduled[25] wind plant in the NEM has increased quite considerably in recent years. This trend is expected to continue until 2020 in response to the Federal Government's RET scheme (recognising the RET is now the subject of a Commonwealth Government review[26]). Figure 20 shows scheduled and semi-scheduled wind generation that has been commissioned to-date as a result of the RET. It also shows committed new investment and forecast investment until 2017.

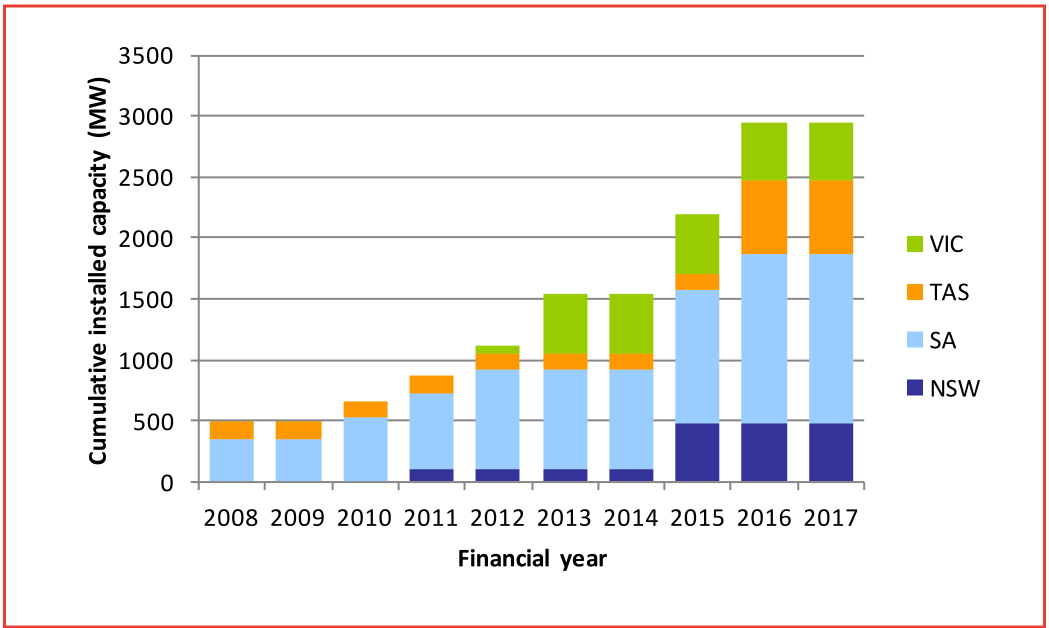
---

24 Wind capacity is measured at 100% of its installed capacity. Forecast demand is taken from AEMO's Scenario 6 Slow Growth forecast. Tasmanian hydro generation has been included in the Installed Capacity and Reserve Plant Margin series from FY2007 onwards to reflect the connection of Tasmania to the mainland system in 2006.

25 This is wind that is scheduled through NEMDE and AEMO. There has also been a large increase in non-scheduled wind capacity, which impacts the market via reduced (scheduled) demand.

26 Department of Environment weblink: http://www.environment.gov.au/topics/cleaner-environment/clean-air/renewable-energy-target-scheme

Figure 20: Scheduled and semi-scheduled wind capacity – actual and forecast



Source: Frontier Economics analysis ESAA and AEMO data, Frontier Economics (forecast)

177 Increased penetration of wind generation has several important implications due to the impact this capacity has on the supply side of the market.

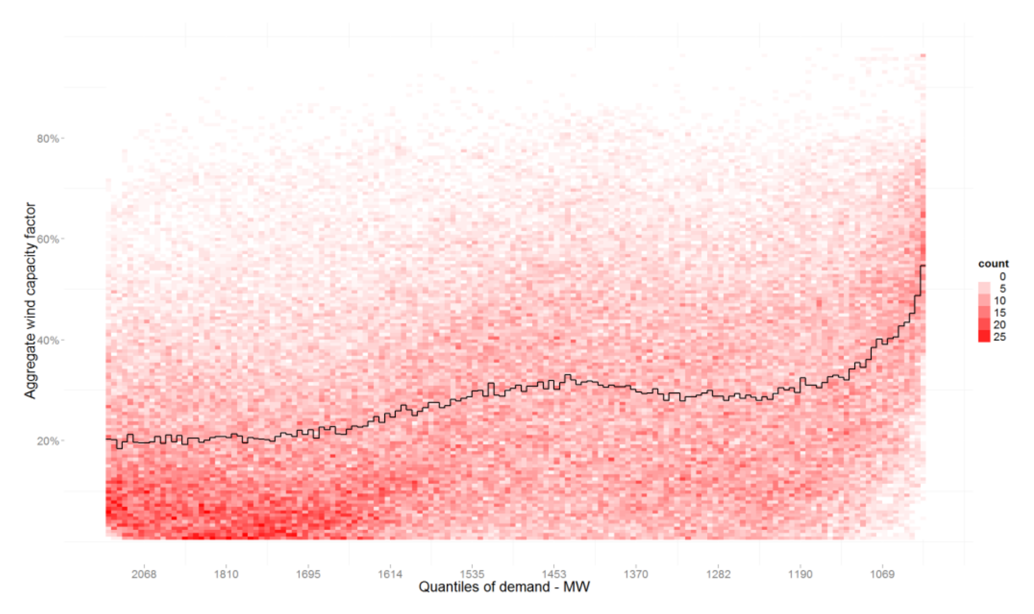
178 These effects reflect the fact that wind is intermittent by nature, and that wind generation operates on a must-run basis when the wind does blow. That is, it is not possible to choose when to run (this is discussed in more detail below). Secondly, the variable costs of wind generation is essentially zero. Both these factors will mean that wind generation will usually be bid into the market at zero or even negative prices to ensure dispatch when they can produce power.

179 This has implications for non-wind generators. As explained in Section 2.4.3, the centralised dispatch protocol underpinning the NEM ensures that the cheapest sources of energy are drawn on first to meet demand. Hence the entry of a significant quantity of generation that is liable to bid at zero or negative prices can be expected to have a moderating impact on prices generally.

6.2.1 Randomness of wind generation

180 Even when a correlation – whether negative or positive – is observed to hold over the long run, there is considerable uncertainty as to the availability of sufficient wind in any given period. This is demonstrated by Figure 21 and Figure 22 below which shows a historical distribution of wind generation in South Australia and Victoria (y-axis) at different percentiles of demand (x-axis).

Figure 21: Historic wind analysis, South Australia (2005-11)

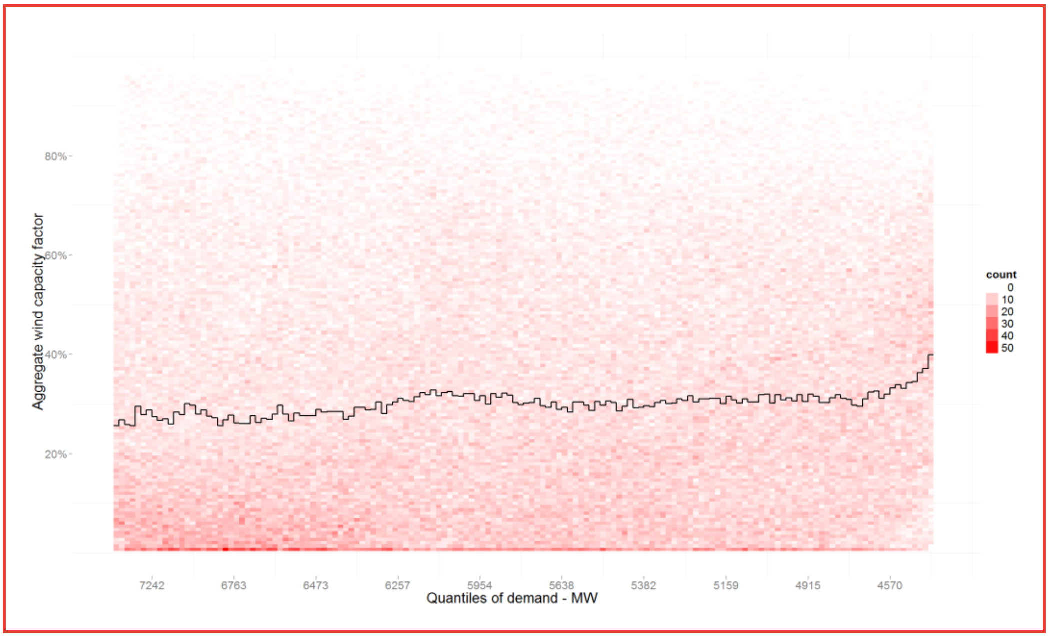


Source: Frontier Economics analysis of AEMO data

181 The percentiles of demand run from highest (left) to lowest right). The density of the aggregate wind capacity factors is shown by the intensity of the red tiles. The average wind capacity factor for each percentile of demand is shown by the solid black line.

182 The analysis confirms that wind in South Australia and Victoria is negatively correlated with demand, with the negative correlation being more pronounced in South Australia than Victoria. Importantly, this negative correlation is on average: in any given half-hour, the actual output of wind can be considerably much lower or higher than its expected value. This is evidenced by the very wide range of possible wind capacity factor outcomes that have occurred during the highest percentiles of demand.

Figure 22: Historic wind analysis, Victoria (2005-11)

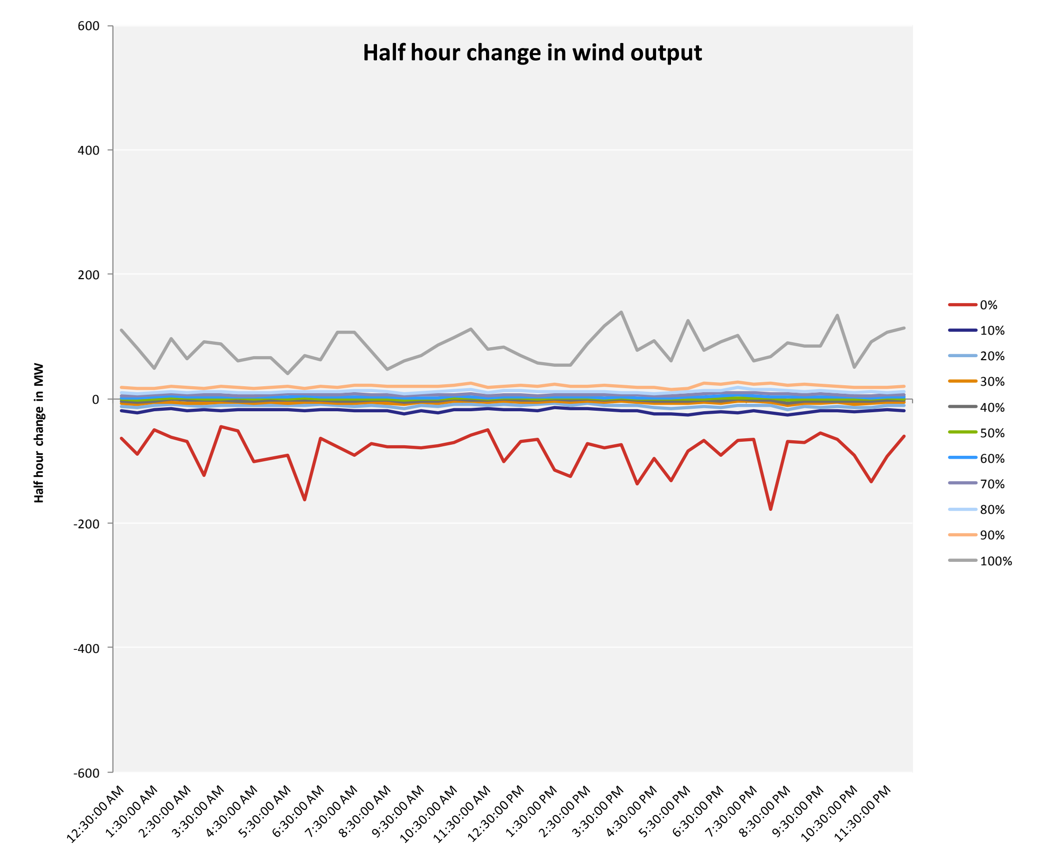


Source: Frontier Economics analysis of AEMO data

183 The stochastic nature of wind introduces considerable uncertainty as to the availability of wind capacity at zero or negative prices. This is something that other generators will need to take into account when bidding capacity into the pool. In particular, if they anticipate low wind availability at periods of high demand, and consequently bid at high prices, they may be displaced by wind capacity as and if it becomes available. Any trading strategy that requires an assumption about forecast wind availability contains a high degree of additional risk due to this uncertainty of how much capacity a generator is competing with at any point in time. This can be particularly challenging for thermal generators, the large majority of which have not been designed to operate flexibly.

184 To illustrate the randomness of wind generation we examine consecutive periods of wind output (from one half hour to the next). Figure 23 shows the distribution of the change in wind output for calendar year 2012 for Victoria by time of day. The average change from the 10-90 percentiles is typically around 0. This analysis indicates that wind output is entirely unpredictable and is as likely to rise as fall from one period to the next. A similar result is observed in the NSW and South Australia wind output data.

Figure 23: CY2012 change in wind output from previous half hour (ramp rates), by percentile, VIC

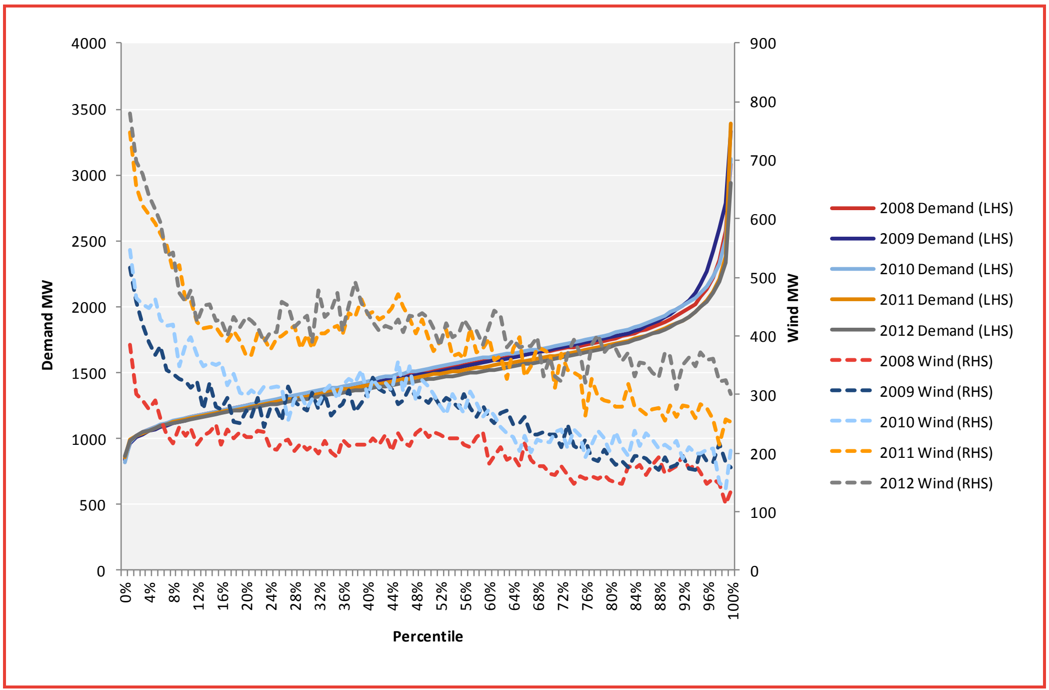


Source: AEMO data, Frontier Economics analysis

6.2.2 Wind generation and demand anti-correlated

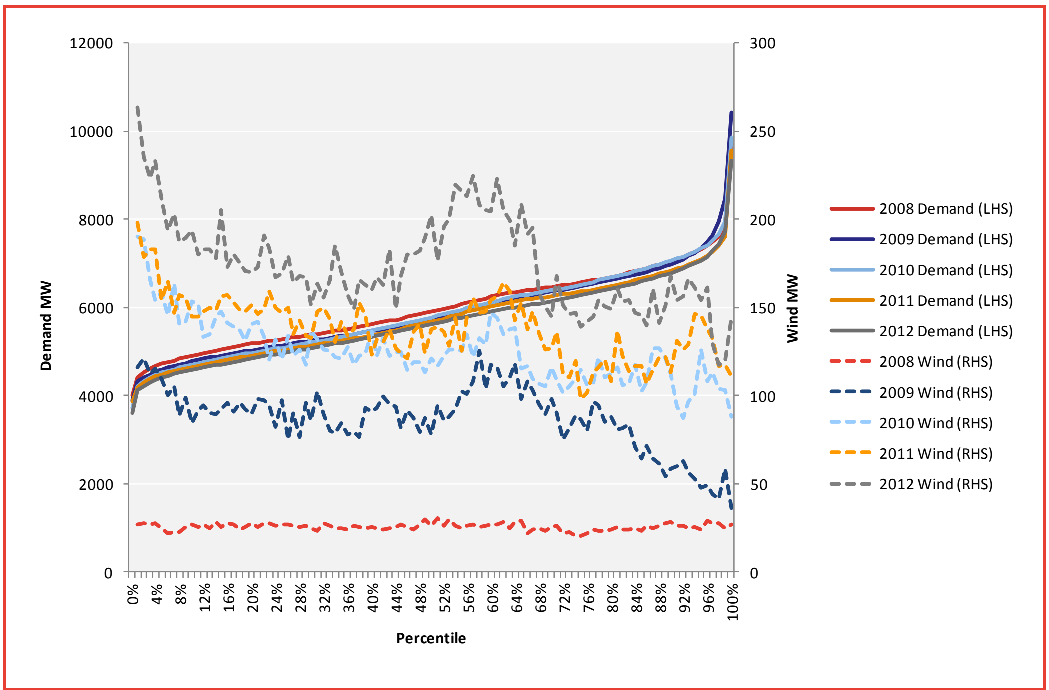
185 It is important to consider the relationship between the availability of wind generation, on one hand, and demand, on the other. This can be understood by examining the strength of the correlation between the two. In the case of South Australia and to a lesser degree Victoria and NSW, based on available data of wind farm output, it appears that the output of wind plant is negatively correlated with regional demand – the wind tends to blow less at times of peak demand than on average.

Figure 24: Profile of demand and wind output – SA (CY Jan 2008 – Dec 2012)



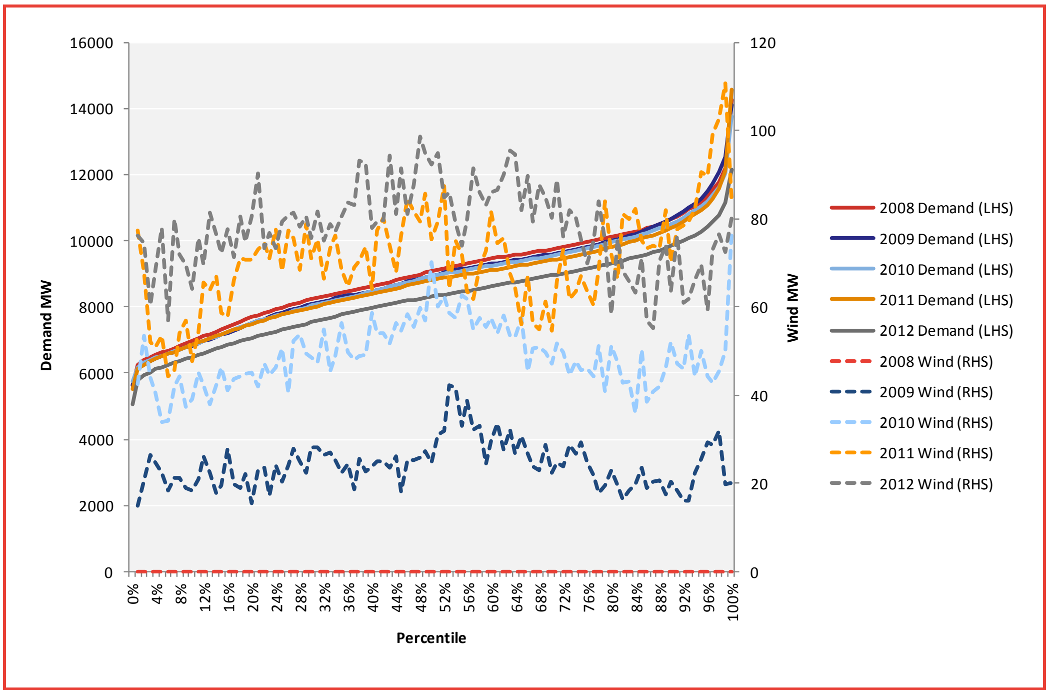
Source: AEMO data, Frontier Economics analysis

Figure 25: Profile of demand and wind output – VIC (CY Jan 2008 – Dec 2012)



Source: AEMO data, Frontier Economics analysis

Figure 26: Profile of demand and wind output – NSW (CY Jan 2008 – Dec 2012)



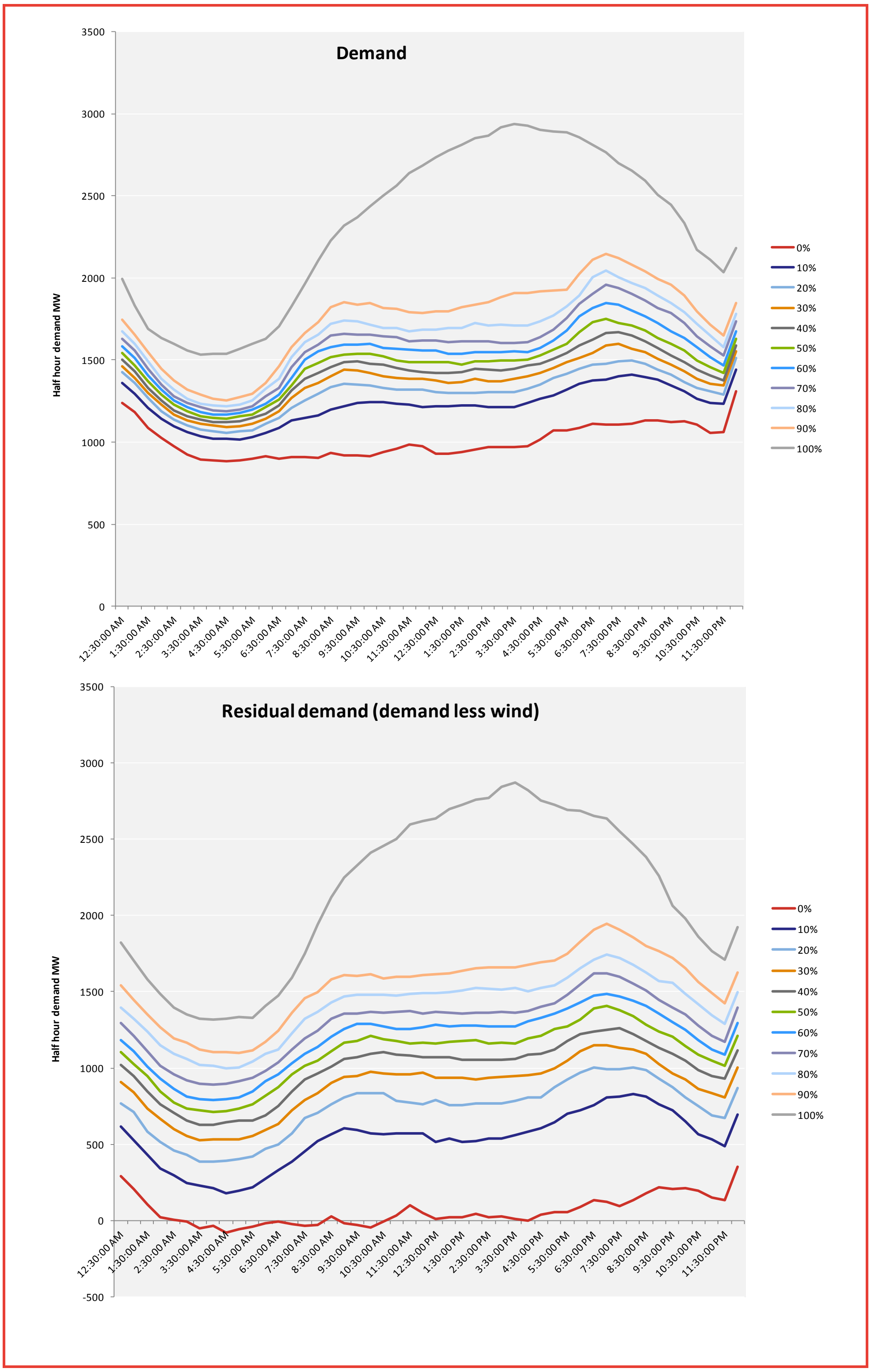
Source: AEMO data, Frontier Economics analysis

186 As a result of the negative correlation between wind output and electricity demand, the residual demand curve faced by thermal generators, once the proportion of demand that could be met by wind is accounted for, is "peakier" and also more volatile. This is illustrated for South Australia in Figure 27. The top chart shows the percentiles of demand by half hour and the bottom chart shows the percentiles of residual demand, which is demand after accounting for wind by half hour. The variance in the residual demand is larger for every half hour compared to the variance of demand illustrating the increase in uncertainty imposed by volatile wind generation. Furthermore, Figure 27 indicates that the 100th percentile remains relatively unaffected by wind generation; however, the lower percentiles are lower in the residual demand chart relative to the demand chart. This indicates that the residual demand faced by baseload generators is "peakier" after accounting for wind generation.

187 The analysis demonstrates that the negative correlation of wind with demand exacerbates the volatility that wind generation imposes on the market. Trading strategies that attempt to profit from withholding in the market must not only account for uncertainty in demand and wind generation separately, but they must account for the possibility of unfavourable demand and wind conditions occurring simultaneously.

Contents

Figure 27: CY2012 demand and residual demand by half hour, percentile, SA



Source: AEMO data, Frontier Economics analysis

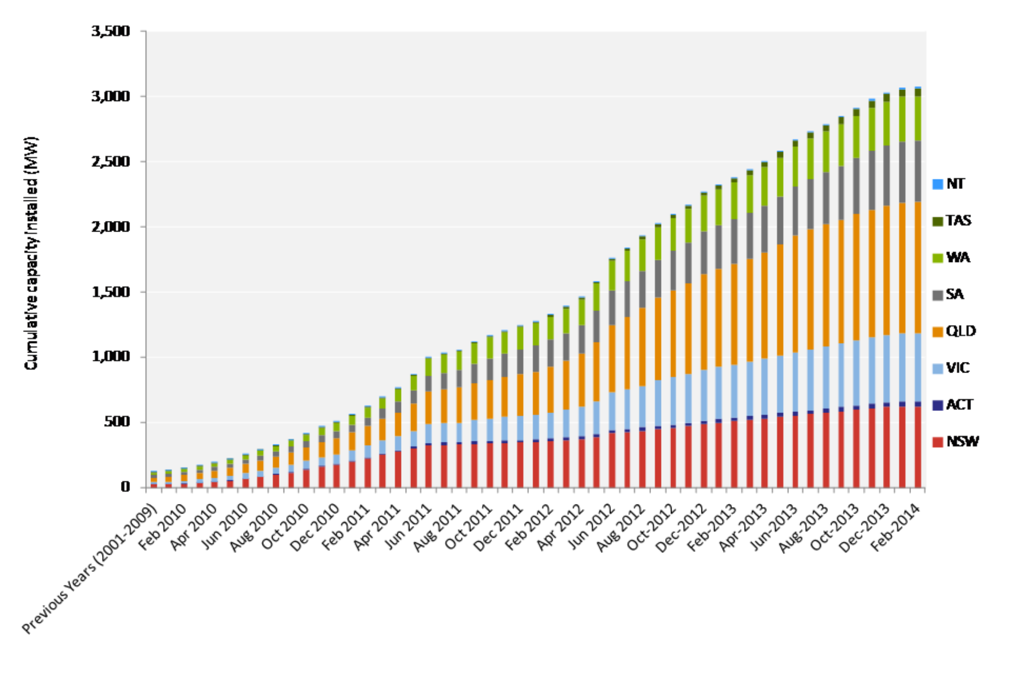
188 In summary, the introduction of significant quantities of wind generation capacity, caused by government subsidy policies has had the following effects on the NEM:

- The introduction of significant amounts of low-priced capacity that will tend to lower overall wholesale prices, all else being equal
- Greater risks that high bidding thermal plants will be positioned outside the merit order. This could cause these plants to operate more variably through time, which they are generally not designed to do economically. In turn, this will raise the costs of these high bidding generators and, together with lower dispatch opportunities, will reduce the incentive to engage in this type of behaviour
- The nature of this intermittent renewable capacity means there is considerable uncertainty regarding the availability of wind both at times of peak demand and in terms of correlation across regions of the NEM.
- The nature of this intermittent renewable capacity means there is considerable uncertainty regarding residual demand to be met with non-wind generation since wind output is poorly correlated with demand in all NEM regions.

6.3 Solar power

189 In addition to large quantities of (non-strategic) wind generation entering the market there has been a rapid rise in the quantity of solar facilities being installed by households and businesses. This rapid growth in solar capacity across Australia is due to the operation of a range of State and Commonwealth subsidy schemes. As can be seen in Figure 28 solar capacity has increased from about 100 MW in February 2010 to around 3,000 MW in February 2014. This increase in solar capacity reduces the demand for generation from the centralised generation system and, all other things being equal (e.g. generation supply), increases the competitiveness between the NEM generators.

Figure 28: Growth in solar capacity (Feb 2010 to Feb 2014)



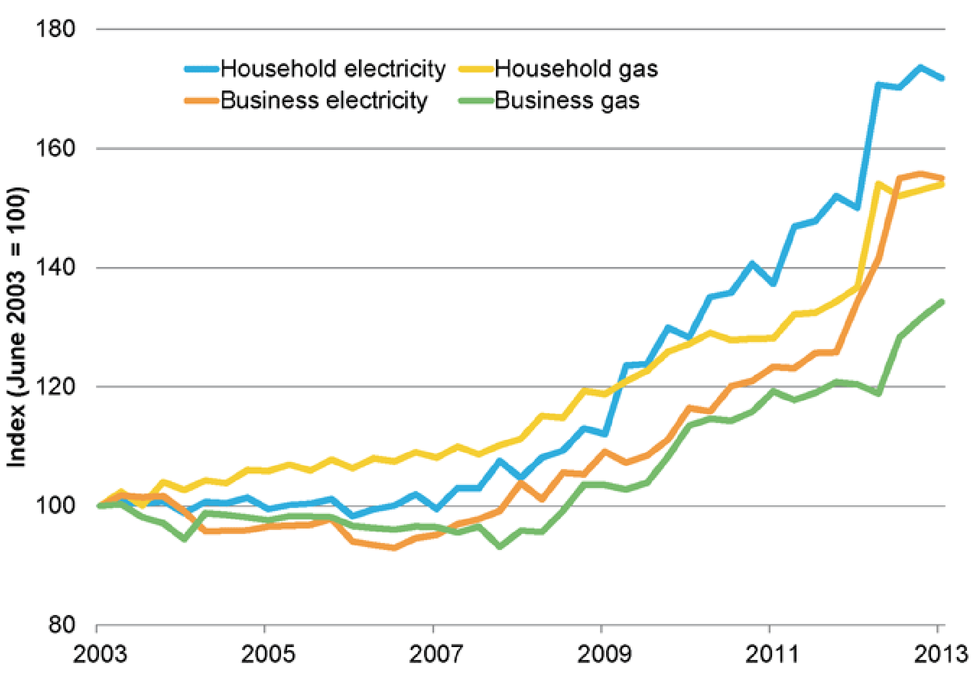
Source: Clean Energy Regulator, Weblink: *Source:* http://ret.cleanenergyregulator.gov.au/REC-Registry/Data-reports

6.4 Retail price trends

190 There is a great deal of commentary in the community about rising energy prices.[27] This is unsurprising given that, according to the Australian Bureau of Statistics data, household retail electricity prices have increased by about 70% over the past ten years (see Figure 29).

27 On 23 August 2012 the Senate of the Australian Parliament referred a Terms of Reference to a Select Committee to inquire into the causes of electricity price rises and to investigate ways to reduce prices. Weblink: http://www.aph.gov.au/~/link.aspx?_id=9DDF5D4746F648C68967380E0C30377F&_z=z

Figure 29: Real retail electricity and gas price movements (2003 to 2013)



Source: Australian Parliamentary Library, weblink http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook44p/EnergyPrices

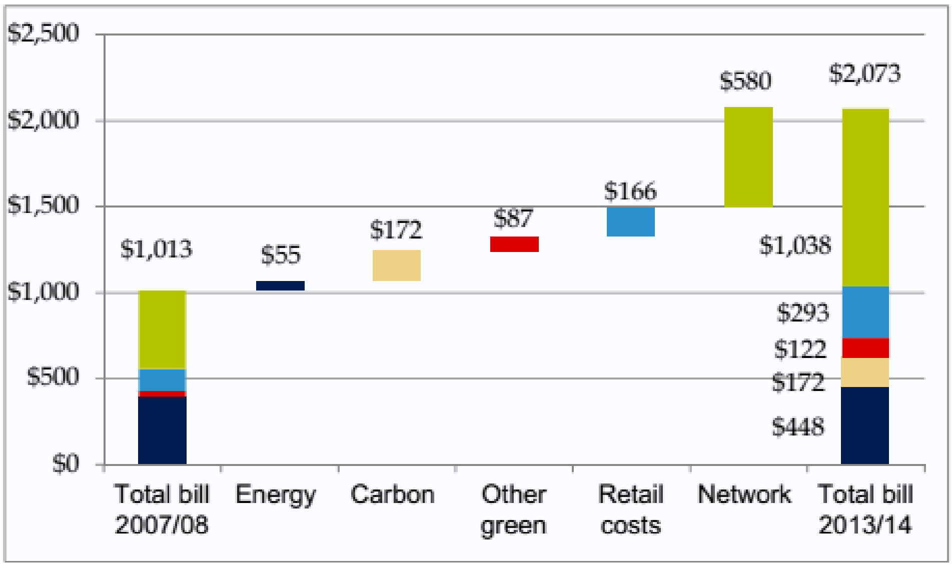
191 IPART recently reviewed *regulated* retail electricity prices in NSW and found that they have more than doubled in nominal terms over the past six years.[28] The two main factors have driven this increase (see Figure 30) are:

- Network costs – over the past six years IPART found that network charges have added around $580 to the average household regulated tariff in NSW. As Figure 2.1 indicates, network charges comprise around half a typical residential customer's annual electricity bill
- Green scheme costs, arising from changes to existing schemes and the introduction of new schemes. For example, the carbon price adds around $172 to a typical regulated residential customer's annual bill. Increases to the costs of complying with other green schemes, including the RET and the NSW Energy Saving Scheme have added another $87 to regulated retail bills since 2007/08.

---

28 IPART, *Review of regulated retail prices and charges for electricity, From 1 July 2013 to 30 June 2016*, Electricity – Final Report, June 2013, pp.17-18.

Figure 30: Breakdown of NSW retail bill increases



Source: IPART (2013)

192 The AEMC makes similar observation about the causes of recent material retail price increases across Australia – that is that network and green cost increases are been the major contributors to retail price rises in recent years.[29]

6.4.1 Wholesale costs

193 Wholesale electricity prices generally follow the movement of the RPM (presented in Figure 19). There are a few key movements in price that are worth noting:

- Soon after the commencement of the NEM wholesale prices trended to converge between the different regions.
- For the first six year prices tended to be below generation costs[30] Prices rose rapidly over 2007 and 2008 reflecting the effects of the drought on the curtailment of available thermal and hydro generation (water is used to cool thermal generators) but then fell rapidly to reflect increased water availability after the drought broke[31] It is worth noting that, as indicated in Figure 19, the RPM fell sharply following the onset of the drought in 2007 and 2008. As previously noted, wholesale prices tend to be negatively correlated with the

---

29 AEMC (2013), 2013 Residential Electricity Price Trends, Final Report, December, Weblink: http://www.aemc.gov.au/media/docs/2013-Residential-Electricity-Price-Trends-Final-Report-723596d1-fe66-43da-aeb6-1ee16770391e-0.PDF

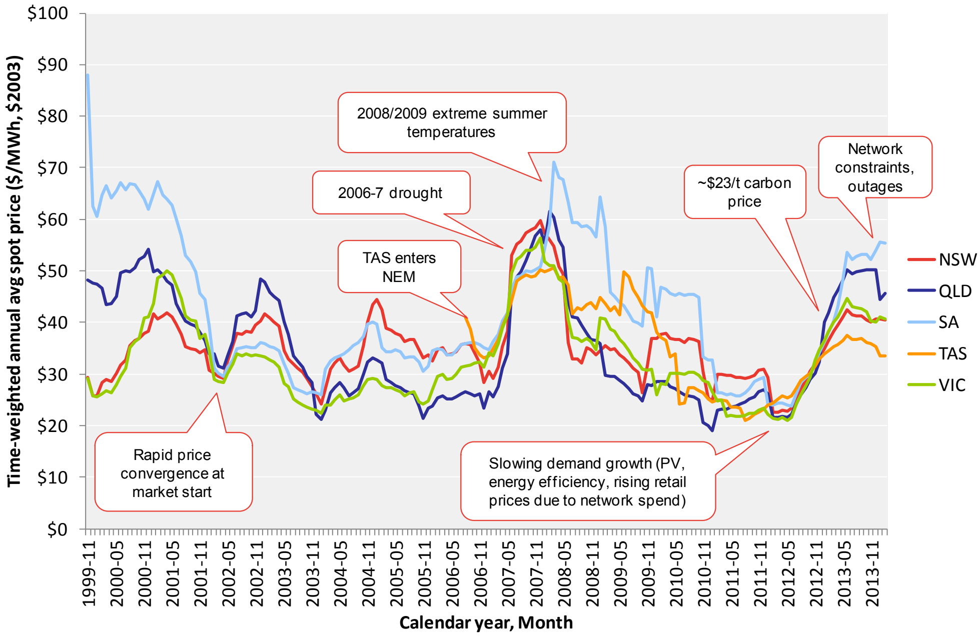
30 *(No 3)* [2003] FCA 1525 (**Loy Yang Case**) at [470] to [493]

31 Frontier Economics (2012), *Annual Energy Cost Review*, Final Report, February p 9.

RPM – that is, as RPM increases, wholesale prices fall (that is, as excess capacity increases, competition intensifies, and prices fall).

- Prices rose again following the introduction of the $23/tonne carbon tax.

Figure 31: Spot electricity since NEM start, by NEM region - in 2003 dollars



Source: AEMO data

6.4.2 Comparing wholesale prices to generator costs

194 As indicated above, French J considered the relationship between generation costs and prices and found that, at the time, prices were in the range of the cost estimates at the time (2000-2001).[32] While wholesale prices can change rapidly in the NEM, the underlying generation cost structure tends not to change materially from year-to-year. On that basis, given that French J found that prices were within the range of generation cost estimates in over the period from NEM start in 1998 to 2003, it seems appropriate to conclude that generation costs and prices are similarly consistent, at least until the drought started to have a sever effect on the availability of generation (as indicated by a sharp decline in the RPM shown in Figure 19).

195 As a consequence of the high levels of RPM being experienced in the NEM, average wholesale prices have been relatively low and lower than most reasonable estimates of the 'long run marginal cost' (LRMC) of generation to meet customer load. The AEMC has undertaken a more recent review of generation costs using

32 at [470] to [493]

similar approaches to that considered by French J in 2003. More specifically, the AEMC considered two approaches for calculating the Long Run Marginal Costs of Generation (LRMC). The AEMC has described LRMC as:

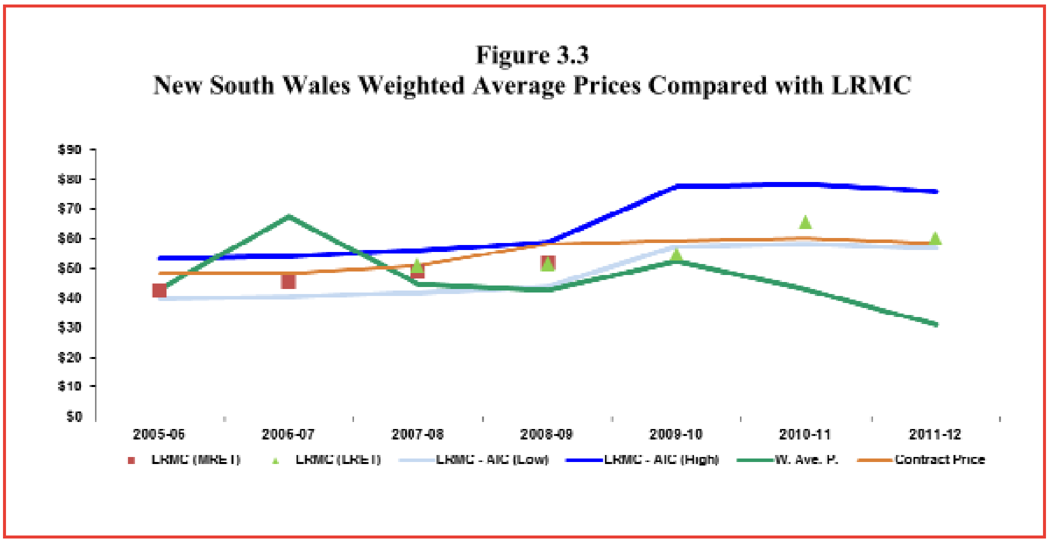
> ...a measure of the workably competitive level of wholesale electricity prices, with actual prices expected to be above this level in some years and below in other years, reflecting supply and demand conditions at particular points in time.[33]

196 The AEMC's two approaches for determining the LRMC of generators are the:

- **Average incremental cost (AIC) or 'standalone' approach:** this involves estimating the least-cost combination of plant to satisfy an increment to end-use customers' demand for electricity.
- **Turvey 'perturbation' approach:** this involves estimating the present value cost of bringing forward new generation to meet an incremental increase in demand over a future time period.[34]

197 Figure 32 compares the average (nominal) wholesale prices in NSW against the AEMC's estimates of LRMC, using both the AIC and Turvey approaches. Figure 32 shows that recent (2005-06 to 2011-12) wholesale spot prices have generally been at the low end of the estimate of LRMC. Using the AEMC's estimate of the generator contract price (as distinct from the spot price), prices have generally been in the mid-point of the AEMC's low and high estimate of the LRMC of generation in NSW.

Figure 32: Recent NEM wholesale prices and LRMC



Source: NERA, "Estimates of the long run marginal cost for electricity generation in the National Electricity Market, 2012

33 AEMC, *Potential Generator Market Power in the NEM, Final Rule Determination*, 26 April 2013, p.iii.,

34 See NERA, *Benchmarking NEM Wholesale Prices Against Estimates of Long run Marginal Cost, A Report for the AEMC*, 12 April 2012, pp.7.-9

6.4.3 Interconnector constraints

198 Capacity constraints on transmission interconnects between regions can cause congestion in a regionally interconnected market such as the NEM resulting in generation plant being dispatched out of merit order. For example, if demand in one region is high and the interconnects connected to that region have reached their physical flow limits into the region, then this may result in high cost generation being dispatched within the high demand even if there is a lower cost generator that has available capacity in a adjoining region.

199 Figure 33 reports the proportion of 5 minute intervals across each financial year where each of interconnects linking to NSW are constrained, which is determined as an interval where the interconnect flow is equal to either the import or export limit[35]. Figure 33 indicates whether the constraint occurs during a period of import or export to NSW. Figure 33 also indicates whether the constraint occurred because flow reached the dynamic import/export limit, labelled as "Binding", or whether it occurred due to the flow being artificially fixed to a particular level, labelled as "Fixed".[36] Fixing the interconnect flow level may be conducted by AEMO in order to 'clamp' flows during period of counter price flows in order to financially protect AEMO against unfunded settlement residues. AEMO may also fix the interconnect flows during periods of outages as has occurred on Terranora for the majority of FY2014.[37]

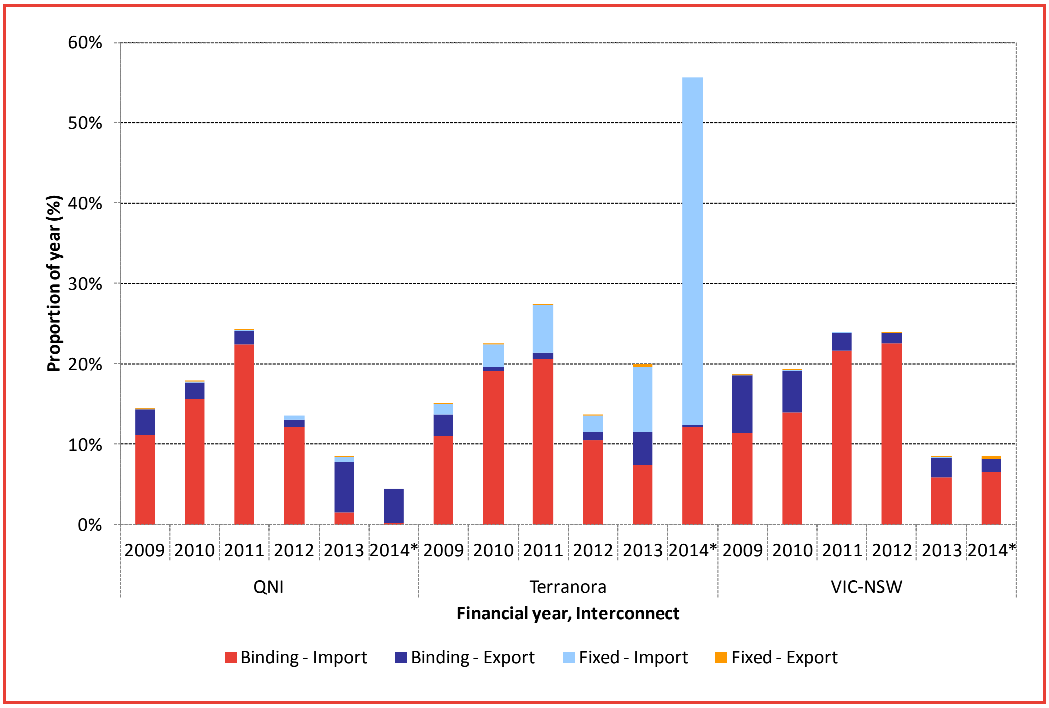
---

35 The flow and import/export limits are determined to be equal if the difference does not exceed 0.001MW.

36 This is determined as instances where the difference between the import and export limits does not exceed 0.001MW.

37 AEMO (2014), "Management of negative inter-regional settlement residues", 20 February, Weblink: http://www.aemc.gov.au/media/docs/Information-Sheet-a6b87479-f885-4ba3-aff5-01ded3b0bcda-0.PDF

Figure 33: Proportion of year interconnects are constrained



Source: Frontier Economics analysis of AEMO data[38]

200 Figure 34, Figure 35 and Figure 36[39] show the relationship between the level of NSW demand and price separation between the constrained regions at times where 1, 2 and 3 interconnects that are import constrained respectively. The height of each bar represents the proportion of 5 minute intervals during which we have historically observed a particular NSW demand and price separation outcome. The width of each bar is 500MW of NSW demand and the colour of the segments corresponds to the degree of price separation. This is measured as the difference between the NSW price and the price of the adjacent region at the exporting end of the constrained interconnect. If there are multiple regions involved, the maximum price difference has been used to categorise the observation.

201 These figures illustrate that the majority of instances where interconnects are constrained are associated with price separation of less than $10. It also illustrates that the occurrence of high levels of price separation is rare. The other trend that is worth noting that instances where more than one of the three interconnects between NSW and other States binds has progressively become more rare, noting that interconnect constraints are not the norm and are rarely severe in terms of

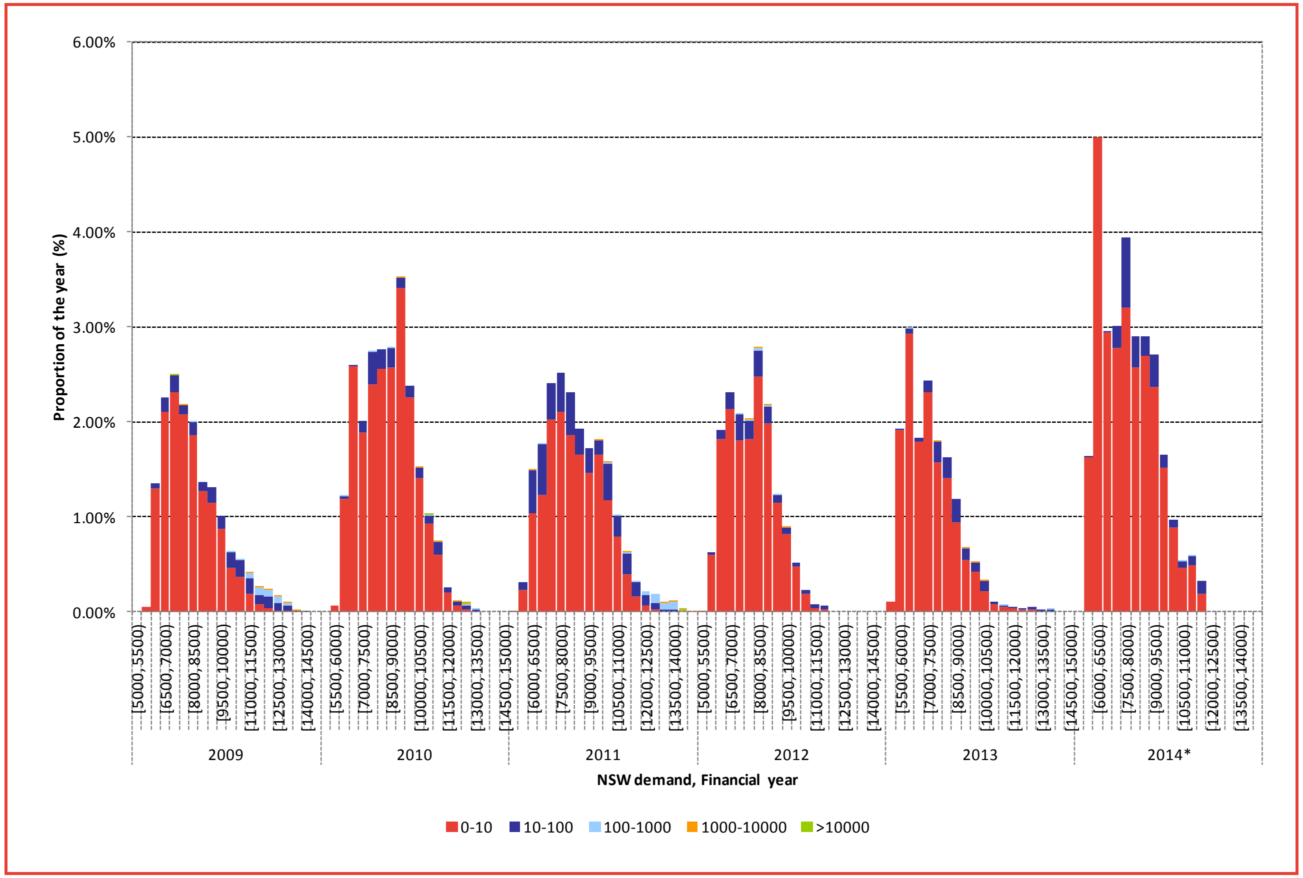
---

38 Proportions for FY2014 have been calculated as the proportion of FY2014 data currently available up to and including 15/3/2014

39 Proportions for FY2014 have been calculated as the proportion of FY2014 data currently available up to and including 15/3/2014

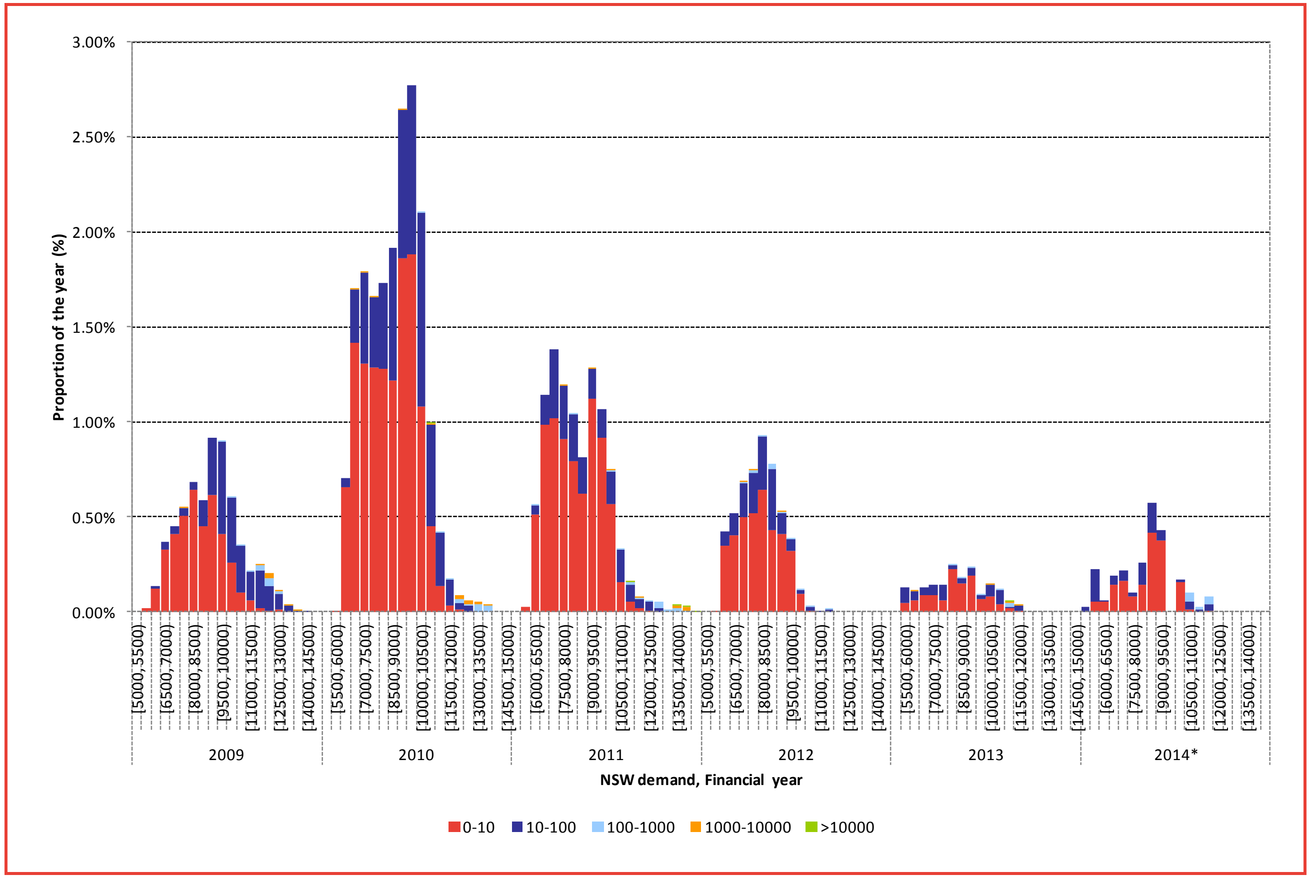
price differences. This trend away from multiple constraints can be seen clearly in Figure 35 and Figure 36 with the incidents of constraints steadily falling from 2010 to the present.

Figure 34: Price separation and demand levels during periods where 1 interconnect is constrained



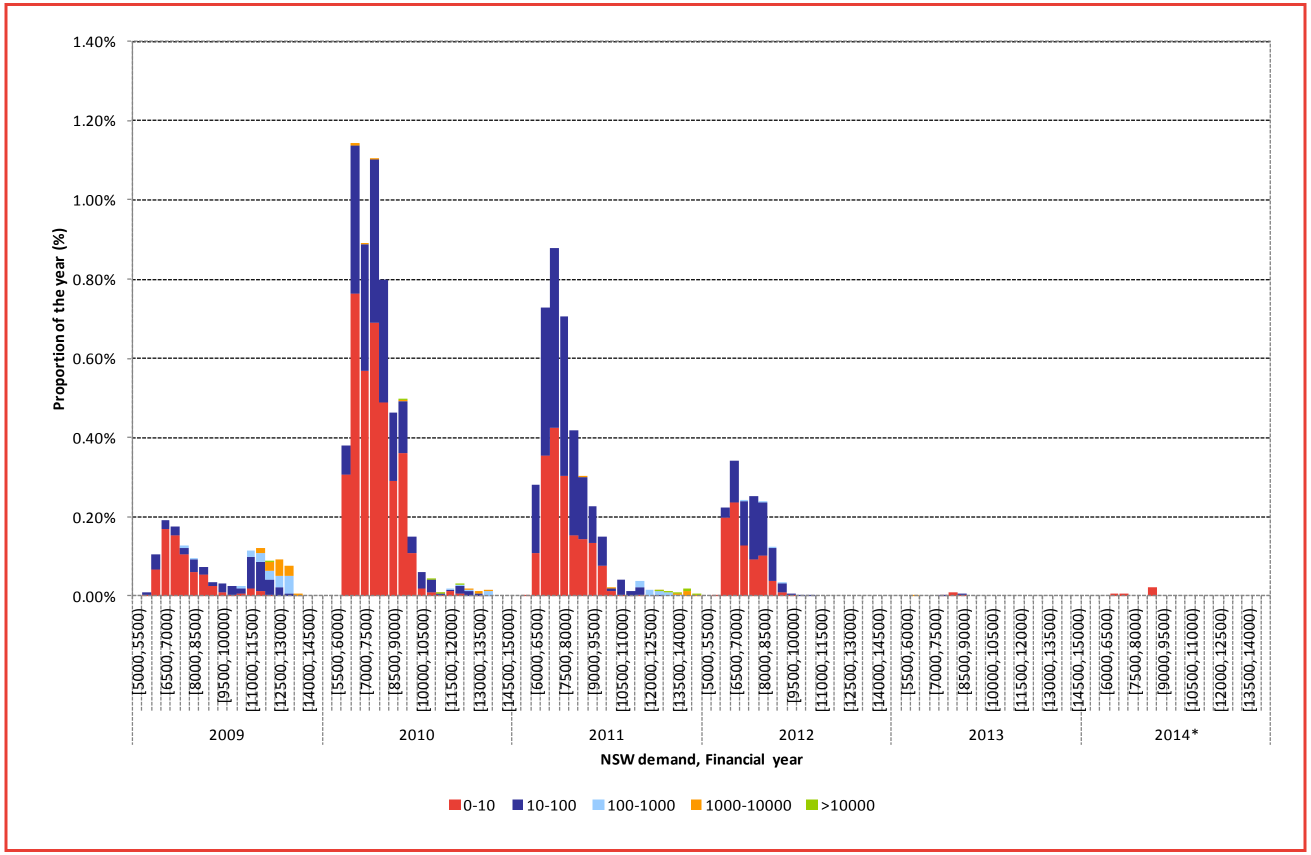
Source: Frontier Economics analysis of AEMO data

Figure 35: Price separation and demand levels during periods where 2 interconnects constrained simultaneously



Source: Frontier Economics analysis of AEMO data

Figure 36: Price separation and demand levels during periods where 3 interconnects constrained simultaneously

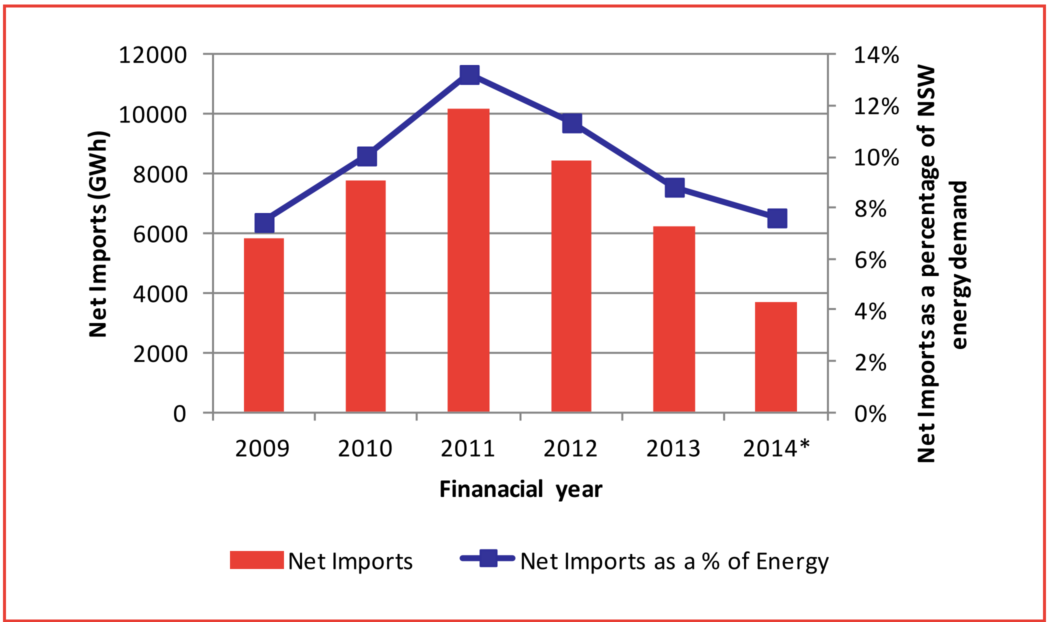


Source: Frontier Economics analysis of AEMO data

6.4.4 NSW interconnector flow

202 Figure 37 illustrates the level of net imports into NSW over the last 5 complete financial years and for FY2014 to date. It shows that NSW is a net importer of energy. It also illustrates net imports as a percentage of NSW energy demand.

Figure 37: NSW imports



Source: Frontier Economics analysis of AEMO data[40]

6.4.5 Conclusion

203 As suggested above, a high RPM generally undermines any opportunity or incentive for generators to influence the wholesale electricity price. The key reason is that in the presence of a high RPM there are many alternative suppliers that can and will meet the demand for capacity if any generator seeks to artificially create capacity scarcity.

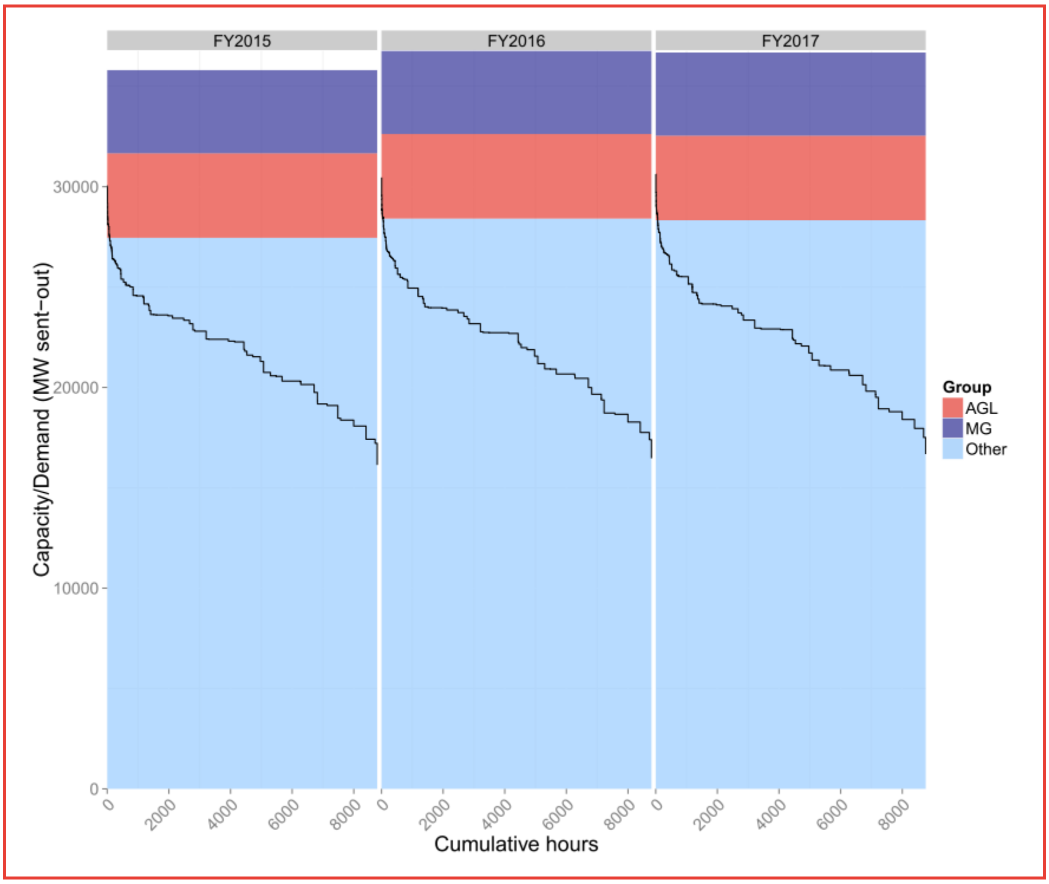
204 Figure 38 seeks to show, in a simplified way, the likely lack of market power AGL or Macquarie Generation are likely to have separately or together given the current state of the NEM or in the foreseeable future.

205 More specifically, Figure 38 overlays a forecast NEM load duration curve (this stacks demand level for each of the 17,520 half hours in a year from the highest on the left hand side of the figure to the lowest on the right hand side) over the

40 FY2014 values includes GWh of flow and NSW energy up to and including 15/3/2014

stack of capacities[41] of each generation portfolio in the NEM. AGL's plants and Macquarie Generation are placed at the top of the stack. All wind and hydro generators are shown in the generation stack at their average capacity, which for the purposes of generators considering engaging in strategic bidding in the NEM, would represent an understatement of the potential competition generators face and, all other things being equal, would tend to overstate the capacity for AGL/Macquarie Generation to successfully influence spot prices. In spite of this it can be clearly seen from Figure 38 that for the all but a few hours in a year there is sufficient capacity in NEM that demand can be met without AGL's capacity plus Macquarie Generation. Of course this highly simplified analysis of the relationship between supply, demand, RPM relative to the size (and, hence, likely influence) of the generators proposed to be merged, ignores many factors that are important in considering the competitiveness in the NEM, including interconnector constraints, transmission losses, and generator outages.

Figure 38: AGL and Macquarie Generation are excess to requirements



Source: AEMO data, Frontier Economics analysis

41 These capacities have been de-rated at the expected outage rate and are on a sent-out basis.

206 This oversupply is unlikely to be a short lived phenomenon. There appears to be no move by any political party to curtail the growth in the stock of renewable capacity. Further, the modelling has incorporated the slowing down in the growth of solar capacity and the effects of higher network prices on electricity demand.

207 Two important aspects that we consider here are, respectively, the increased importance of renewable capacity in the NEM (discussed briefly above), and projected developments in demand. Both jointly impact on the overall balance of the supply of and demand for energy which, especially in an energy-only market – has an important bearing on the commerciality of different types of generation activities in the NEM.

Annex A: Generation market shares

208 This Annex presents generation market shares for the last 5 financial years. The market shares have been calculated on both a NEM and a NSW basis. The market shares have been calculated on a capacity, output and pool revenue basis. These market shares include scheduled and semi-scheduled generators only. Non-scheduled generation has not been included. Exclusion of non-scheduled generation is not material for the calculation of market shares as they form a small share of total NEM generation. Furthermore, the capacity is non-strategic as they not participate in the central dispatch process.

209 This Annex also presents the raw data used to calculate these market shares.

Table 11: NEM market shares – Capacity

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.0%	0.1%	0.1%
AGL	7.5%	7.5%	7.7%	7.9%	11.9%
Alcoa	0.4%	0.3%	0.3%	0.3%	0.3%
Alinta	0.0%	2.4%	2.9%	2.7%	2.2%
Arrow	0.0%	0.0%	0.0%	1.1%	1.1%
Aurora	0.3%	0.9%	1.0%	1.0%	1.0%
Babcock	3.4%	0.8%	0.0%	0.0%	0.0%
Comalco	3.9%	0.0%	0.0%	0.0%	0.0%
CS	6.4%	6.1%	5.9%	8.6%	8.6%
Delta	9.8%	10.6%	9.4%	5.5%	4.3%
EA	6.6%	6.8%	7.9%	11.7%	11.8%
EnergyBrix	0.4%	0.4%	0.4%	0.4%	0.4%
Eraring	6.7%	6.4%	4.8%	0.1%	0.1%
Ergon	0.1%	0.1%	0.1%	0.1%	0.1%
ERM	0.0%	1.1%	1.1%	0.0%	0.0%
HydroTas	5.6%	4.8%	4.6%	4.6%	4.6%
Infigen	0.4%	0.4%	0.4%	0.5%	0.5%

Infratil	0.3%	0.3%	0.3%	0.3%	0.3%
Intergen	3.0%	2.9%	2.8%	2.7%	2.8%
IP	8.0%	7.7%	7.4%	7.3%	7.4%
LoyYang	3.3%	3.2%	3.1%	3.1%	0.0%
MacGen	10.9%	10.5%	10.2%	10.1%	10.2%
Marubeni	0.4%	0.4%	0.3%	0.3%	0.3%
Origin	3.0%	3.6%	6.5%	11.3%	12.6%
PacHydro	0.0%	0.1%	0.1%	0.1%	0.1%
QGC	0.0%	0.2%	0.3%	0.3%	0.3%
RATCH	0.0%	0.0%	0.0%	0.4%	0.2%
Redbank	0.0%	0.0%	0.2%	0.3%	0.3%
Rio	0.0%	0.0%	0.3%	0.3%	0.3%
Roaring40s	0.0%	0.0%	0.2%	0.0%	0.0%
Snowy	10.1%	9.7%	9.4%	9.7%	10.0%
Stanwell	3.8%	7.3%	7.1%	9.1%	8.2%
Tarong	5.4%	5.2%	5.0%	0.0%	0.0%
Transfield	0.4%	0.4%	0.4%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Table 12: Aggregate NEM capacity by portfolio (MW)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	12	47	47
AGL	3,242	3,400	3,595	3,743	5,610
Alcoa	158	158	158	158	158
Alinta	0	1,080	1,365	1,290	1,050

Arrow	0	0	0	519	519
Aurora	147	403	455	455	455
Babcock	1,482	360	0	0	0
Comalco	1,680	0	0	0	0
CS	2,770	2,770	2,770	4,080	4,080
Delta	4,240	4,783	4,394	2,644	2,044
EA	2,878	3,095	3,700	5,566	5,566
EnergyBrix	170	170	170	170	170
Eraring	2,909	2,909	2,249	29	29
Ergon	55	55	55	55	55
ERM	0	519	519	0	0
HydroTas	2,415	2,175	2,175	2,175	2,175
Infigen	160	160	199	235	247
Infratil	124	149	149	149	149
Intergen	1,306	1,306	1,306	1,306	1,306
IP	3,486	3,486	3,486	3,486	3,486
LoyYang	1,431	1,431	1,443	1,478	0
MacGen	4,750	4,750	4,790	4,830	4,830
Marubeni	162	162	162	162	162
Origin	1,321	1,653	3,063	5,403	5,953
PacHydro	0	29	57	57	57
QGC	0	70	140	140	140
RATCH	0	0	0	180	90
Redbank	0	0	75	150	150
Rio	0	0	160	160	160
Roaring40s	0	0	83	0	0
Snowy	4,409	4,409	4,409	4,634	4,709

Stanwell	1,648	3,328	3,328	4,361	3,861
Tarong	2,343	2,343	2,343	0	0
Transfield	180	180	180	0	0
Total	43,466	45,333	46,990	47,662	47,258

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Table 13: NSW market shares – Capacity

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.1%	0.3%	0.3%
AGL	0.0%	0.0%	0.0%	0.0%	0.0%
Alcoa	0.0%	0.0%	0.0%	0.0%	0.0%
Alinta	0.0%	0.7%	0.5%	0.0%	0.0%
Arrow	0.0%	0.0%	0.0%	0.0%	0.0%
Aurora	0.0%	0.0%	0.0%	0.0%	0.0%
Babcock	1.0%	0.2%	0.0%	0.0%	0.0%
Comalco	0.0%	0.0%	0.0%	0.0%	0.0%
CS	0.0%	0.0%	0.0%	0.0%	0.0%
Delta	28.2%	29.7%	26.7%	15.6%	12.4%
EA	1.4%	2.7%	6.2%	16.4%	16.9%
EnergyBrix	0.0%	0.0%	0.0%	0.0%	0.0%
Eraring	19.4%	18.1%	13.6%	0.2%	0.2%
Ergon	0.0%	0.0%	0.0%	0.0%	0.0%
ERM	0.0%	0.0%	0.0%	0.0%	0.0%
HydroTas	0.0%	0.0%	0.0%	0.0%	0.0%
Infigen	0.0%	0.0%	0.0%	0.2%	0.3%
Infratil	0.0%	0.0%	0.0%	0.0%	0.0%

Contents

Intergen	0.0%	0.0%	0.0%	0.0%	0.0%
IP	0.0%	0.0%	0.0%	0.0%	0.0%
LoyYang	0.0%	0.0%	0.0%	0.0%	0.0%
MacGen	31.6%	29.5%	29.1%	28.5%	29.4%
Marubeni	1.1%	1.0%	1.0%	1.0%	1.0%
Origin	2.2%	4.1%	8.8%	22.3%	23.0%
PacHydro	0.0%	0.0%	0.0%	0.0%	0.0%
QGC	0.0%	0.0%	0.0%	0.0%	0.0%
RATCH	0.0%	0.0%	0.0%	0.0%	0.0%
Redbank	0.0%	0.0%	0.5%	0.9%	0.9%
Rio	0.0%	0.0%	0.0%	0.0%	0.0%
Roaring40s	0.0%	0.0%	0.0%	0.0%	0.0%
Snowy	15.0%	14.0%	13.7%	14.6%	15.6%
Stanwell	0.0%	0.0%	0.0%	0.0%	0.0%
Tarong	0.0%	0.0%	0.0%	0.0%	0.0%
Transfield	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Table 14: Aggregate NSW capacity by portfolio (MW)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	12	47	47
AGL	0	0	0	0	0
Alcoa	0	0	0	0	0
Alinta	0	113	75	0	0
Arrow	0	0	0	0	0

Aurora	0	0	0	0	0
Babcock	150	38	0	0	0
Comalco	0	0	0	0	0
CS	0	0	0	0	0
Delta	4,240	4,783	4,394	2,644	2,044
EA	218	435	1,020	2,775	2,775
EnergyBrix	0	0	0	0	0
Eraring	2,909	2,909	2,249	29	29
Ergon	0	0	0	0	0
ERM	0	0	0	0	0
HydroTas	0	0	0	0	0
Infigen	0	0	0	36	48
Infratil	0	0	0	0	0
Intergen	0	0	0	0	0
IP	0	0	0	0	0
LoyYang	0	0	0	0	0
MacGen	4,750	4,750	4,790	4,830	4,830
Marubeni	162	162	162	162	162
Origin	332	664	1,444	3,784	3,784
PacHydro	0	0	0	0	0
QGC	0	0	0	0	0
RATCH	0	0	0	0	0
Redbank	0	0	75	150	150
Rio	0	0	0	0	0
Roaring40s	0	0	0	0	0
Snowy	2,256	2,256	2,256	2,481	2,556
Stanwell	0	0	0	0	0

Tarong	0	0	0	0	0
Transfield	0	0	0	0	0
Total	15,017	16,109	16,477	16,938	16,425

Source: Frontier Economics analysis based on AEMO Generation Information and public reports

Table 15: NEM market shares – Output

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.0%	0.1%	0.1%
AGL	4.7%	5.0%	5.0%	5.4%	11.2%
Alcoa	0.6%	0.6%	0.6%	0.6%	0.6%
Alinta	0.0%	2.7%	3.3%	2.4%	2.0%
Arrow	0.0%	0.0%	0.0%	0.5%	0.5%
Aurora	0.1%	0.6%	0.8%	0.8%	0.9%
Babcock	3.7%	0.9%	0.0%	0.0%	0.0%
Comalco	3.8%	0.0%	0.0%	0.0%	0.0%
CS	7.8%	7.8%	7.2%	9.3%	9.5%
Delta	12.2%	11.4%	9.2%	3.0%	3.9%
EA	6.8%	7.0%	9.3%	15.0%	13.2%
EnergyBrix	0.6%	0.6%	0.6%	0.6%	0.1%
Eraring	7.5%	6.9%	4.9%	0.1%	0.1%
Ergon	0.0%	0.0%	0.0%	0.0%	0.0%
ERM	0.0%	0.8%	0.6%	0.0%	0.0%
HydroTas	3.6%	3.8%	4.4%	4.0%	5.3%
Infigen	0.2%	0.1%	0.2%	0.3%	0.3%
Infratil	0.2%	0.2%	0.2%	0.2%	0.2%
Intergen	4.4%	4.6%	4.3%	4.3%	4.7%

IP	11.6%	11.2%	11.2%	11.8%	11.8%
LoyYang	5.4%	5.7%	5.6%	5.8%	0.0%
MacGen	13.7%	12.7%	11.2%	13.1%	12.0%
Marubeni	0.5%	0.5%	0.5%	0.5%	0.5%
Origin	0.9%	1.5%	4.4%	8.5%	9.4%
PacHydro	0.0%	0.1%	0.1%	0.1%	0.1%
QGC	0.0%	0.1%	0.3%	0.3%	0.3%
RATCH	0.0%	0.0%	0.0%	0.1%	0.0%
Redbank	0.0%	0.0%	0.2%	0.5%	0.6%
Rio	0.0%	0.0%	0.6%	0.7%	0.7%
Roaring40s	0.0%	0.0%	0.1%	0.0%	0.0%
Snowy	1.9%	2.0%	2.6%	1.7%	2.7%
Stanwell	4.4%	8.0%	6.9%	10.3%	9.5%
Tarong	5.3%	5.0%	5.3%	0.0%	0.0%
Transfield	0.3%	0.2%	0.2%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis of AEMO data

Table 16: Aggregate NEM output by portfolio (GWh)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	35	152	155
AGL	9,781	10,295	10,272	10,775	21,714
Alcoa	1,195	1,331	1,280	1,237	1,094
Alinta	0	5,542	6,713	4,850	3,799
Arrow	0	0	0	981	1,005
Aurora	169	1,202	1,560	1,621	1,826

Babcock	7,688	1,808	0	0	0
Comalco	7,974	0	0	0	0
CS	16,246	16,144	14,759	18,480	18,455
Delta	25,418	23,508	18,742	6,076	7,550
EA	14,230	14,488	18,888	29,842	25,602
EnergyBrix	1,227	1,268	1,259	1,194	155
Eraring	15,698	14,285	9,931	273	233
Ergon	2	3	6	13	9
ERM	103	1,703	1,235	0	0
HydroTas	7,482	7,789	8,890	7,944	10,246
Infigen	367	296	451	603	624
Infratil	322	359	348	377	375
Intergen	9,174	9,450	8,865	8,533	9,065
IP	24,141	23,141	22,878	23,635	23,022
LoyYang	11,275	11,741	11,394	11,585	0
MacGen	28,543	26,131	22,909	26,157	23,332
Marubeni	1,043	1,023	1,023	1,010	1,004
Origin	1,983	3,142	8,985	17,041	18,243
PacHydro	3	164	169	176	168
QGC	0	298	692	586	607
RATCH	0	0	0	214	0
Redbank	0	0	509	1,036	1,072
Rio	0	0	1,218	1,360	1,362
Roaring40s	0	0	229	0	0
Snowy	3,907	4,197	5,353	3,320	5,207
Stanwell	9,251	16,488	14,079	20,465	18,373
Tarong	11,058	10,271	10,877	0	0

Transfield	536	390	465	0	0
Total	208,816	206,457	204,020	199,533	194,299

Source: Frontier Economics analysis of AEMO data

Table 17: NSW market shares – Output

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.1%	0.2%	0.2%
AGL	0.0%	0.0%	0.0%	0.0%	0.0%
Alcoa	0.0%	0.0%	0.0%	0.0%	0.0%
Alinta	0.0%	1.1%	0.9%	0.0%	0.0%
Arrow	0.0%	0.0%	0.0%	0.0%	0.0%
Aurora	0.0%	0.0%	0.0%	0.0%	0.0%
Babcock	1.0%	0.4%	0.0%	0.0%	0.0%
Comalco	0.0%	0.0%	0.0%	0.0%	0.0%
CS	0.0%	0.0%	0.0%	0.0%	0.0%
Delta	34.2%	33.3%	27.7%	9.1%	11.6%
EA	1.1%	3.4%	10.3%	26.5%	25.7%
EnergyBrix	0.0%	0.0%	0.0%	0.0%	0.0%
Eraring	21.1%	20.2%	14.6%	0.4%	0.3%
Ergon	0.0%	0.0%	0.0%	0.0%	0.0%
ERM	0.0%	0.0%	0.0%	0.0%	0.0%
HydroTas	0.0%	0.0%	0.0%	0.0%	0.0%
Infigen	0.0%	0.0%	0.0%	0.2%	0.2%
Infratil	0.0%	0.0%	0.0%	0.0%	0.0%
Intergen	0.0%	0.0%	0.0%	0.0%	0.0%
IP	0.0%	0.0%	0.0%	0.0%	0.0%

LoyYang	0.0%	0.0%	0.0%	0.0%	0.0%
MacGen	38.4%	37.0%	33.9%	39.3%	35.9%
Marubeni	1.4%	1.4%	1.5%	1.5%	1.5%
Origin	0.3%	0.5%	6.9%	18.4%	18.5%
PacHydro	0.0%	0.0%	0.0%	0.0%	0.0%
QGC	0.0%	0.0%	0.0%	0.0%	0.0%
RATCH	0.0%	0.0%	0.0%	0.0%	0.0%
Redbank	0.0%	0.0%	0.8%	1.6%	1.7%
Rio	0.0%	0.0%	0.0%	0.0%	0.0%
Roaring40s	0.0%	0.0%	0.0%	0.0%	0.0%
Snowy	2.7%	2.6%	3.3%	2.9%	4.4%
Stanwell	0.0%	0.0%	0.0%	0.0%	0.0%
Tarong	0.0%	0.0%	0.0%	0.0%	0.0%
Transfield	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis of AEMO data

Table 18: Aggregate NSW output by portfolio (GWh)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	35	152	155
AGL	0	0	0	0	0
Alcoa	0	0	0	0	0
Alinta	0	757	601	0	0
Arrow	0	0	0	0	0
Aurora	0	0	0	0	0
Babcock	772	255	0	0	0

Comalco	0	0	0	0	0
CS	0	0	0	0	0
Delta	25,418	23,508	18,742	6,076	7,550
EA	802	2,418	6,985	17,627	16,678
EnergyBrix	0	0	0	0	0
Eraring	15,667	14,265	9,899	255	213
Ergon	0	0	0	0	0
ERM	0	0	0	0	0
HydroTas	0	0	0	0	0
Infigen	0	0	4	130	146
Infratil	0	0	0	0	0
Intergen	0	0	0	0	0
IP	0	0	0	0	0
LoyYang	0	0	0	0	0
MacGen	28,543	26,131	22,909	26,157	23,332
Marubeni	1,043	1,023	1,023	1,010	1,004
Origin	193	372	4,652	12,227	11,990
PacHydro	0	0	0	0	0
QGC	0	0	0	0	0
RATCH	0	0	0	0	0
Redbank	0	0	509	1,036	1,072
Rio	0	0	0	0	0
Roaring40s	0	0	0	0	0
Snowy	1,973	1,842	2,241	1,955	2,839
Stanwell	0	0	0	0	0
Tarong	0	0	0	0	0
Transfield	0	0	0	0	0

Contents

Total	74,411	70,570	67,601	66,626	64,979

Source: Frontier Economics analysis of AEMO data

Table 19: NEM Market share - Revenue

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.0%	0.1%	0.1%
AGL	6.0%	5.9%	5.3%	5.4%	9.9%
Alcoa	0.5%	0.5%	0.5%	0.6%	0.5%
Alinta	0.0%	3.8%	2.9%	2.5%	2.1%
Arrow	0.0%	0.0%	0.0%	0.6%	0.7%
Aurora	0.3%	0.5%	0.8%	0.9%	0.8%
Babcock	4.1%	0.5%	0.0%	0.0%	0.0%
Comalco	3.3%	0.0%	0.0%	0.0%	0.0%
CS	6.2%	5.8%	6.4%	9.3%	10.8%
Delta	10.9%	12.0%	11.3%	3.1%	3.6%
EA	7.5%	6.8%	7.9%	14.6%	12.5%
EnergyBrix	0.6%	0.5%	0.5%	0.5%	0.1%
Eraring	6.7%	6.8%	5.7%	0.1%	0.1%
Ergon	0.0%	0.0%	0.0%	0.0%	0.0%
ERM	0.1%	0.9%	0.8%	0.0%	0.0%
HydroTas	5.0%	2.4%	3.4%	4.3%	4.2%
Infigen	0.2%	0.2%	0.1%	0.3%	0.3%
Infratil	0.2%	0.2%	0.2%	0.2%	0.2%
Intergen	3.4%	3.3%	3.7%	4.2%	5.3%
IP	11.9%	10.3%	9.1%	11.1%	11.7%
LoyYang	5.2%	4.4%	4.2%	5.3%	0.0%

MacGen	13.2%	13.9%	13.2%	13.5%	11.1%
Marubeni	0.5%	0.6%	0.6%	0.5%	0.5%
Origin	1.6%	3.3%	5.1%	9.0%	9.8%
PacHydro	0.0%	0.1%	0.1%	0.1%	0.1%
QGC	0.0%	0.1%	0.3%	0.3%	0.4%
RATCH	0.0%	0.0%	0.0%	0.1%	0.0%
Redbank	0.0%	0.0%	0.4%	0.5%	0.5%
Rio	0.0%	0.0%	0.5%	0.7%	0.8%
Roaring40s	0.0%	0.0%	0.1%	0.0%	0.0%
Snowy	4.6%	6.7%	5.2%	2.0%	3.2%
Stanwell	3.7%	6.6%	6.6%	10.2%	10.7%
Tarong	4.2%	3.9%	5.0%	0.0%	0.0%
Transfield	0.2%	0.2%	0.2%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis of AEMO data

Table 20: Aggregate NEM pool revenue by portfolio ($m)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	1	4	8
AGL	553	558	385	318	1,158
Alcoa	46	49	35	33	62
Alinta	0	353	210	145	250
Arrow	0	0	0	34	85
Aurora	23	44	56	55	94
Babcock	378	47	0	0	0
Comalco	301	0	0	0	0

Contents

CS	565	543	465	550	1,258
Delta	996	1,124	824	185	425
EA	686	641	576	868	1,457
EnergyBrix	52	46	34	33	9
Eraring	616	635	415	8	13
Ergon	0	2	1	1	1
ERM	5	82	55	0	0
HydroTas	460	228	248	254	495
Infigen	17	14	10	17	36
Infratil	21	18	13	11	21
Intergen	313	307	269	250	616
IP	1,095	971	662	657	1,367
LoyYang	476	413	302	317	0
MacGen	1,211	1,305	958	799	1,298
Marubeni	45	53	42	31	56
Origin	144	308	368	533	1,149
PacHydro	0	9	4	5	9
QGC	0	10	23	17	42
RATCH	0	0	0	6	0
Redbank	0	0	27	31	59
Rio	0	0	39	39	90
Roaring40s	0	0	5	0	0
Snowy	420	633	379	118	369
Stanwell	337	620	482	607	1,252
Tarong	390	363	362	0	0
Transfield	21	15	17	0	0
Total	9,169	9,388	7,271	5,927	11,679

Source: Frontier Economics analysis of AEMO data

Table 21: NSW Market share - Revenue

FY	2009	2010	2011	2012	2013
ACCIONA	0.0%	0.0%	0.0%	0.2%	0.2%
AGL	0.0%	0.0%	0.0%	0.0%	0.0%
Alcoa	0.0%	0.0%	0.0%	0.0%	0.0%
Alinta	0.0%	0.9%	0.5%	0.0%	0.0%
Arrow	0.0%	0.0%	0.0%	0.0%	0.0%
Aurora	0.0%	0.0%	0.0%	0.0%	0.0%
Babcock	0.8%	0.2%	0.0%	0.0%	0.0%
Comalco	0.0%	0.0%	0.0%	0.0%	0.0%
CS	0.0%	0.0%	0.0%	0.0%	0.0%
Delta	31.8%	29.9%	27.9%	9.0%	11.6%
EA	1.1%	3.5%	7.8%	26.2%	25.5%
EnergyBrix	0.0%	0.0%	0.0%	0.0%	0.0%
Eraring	19.6%	16.9%	14.0%	0.4%	0.3%
Ergon	0.0%	0.0%	0.0%	0.0%	0.0%
ERM	0.0%	0.0%	0.0%	0.0%	0.0%
HydroTas	0.0%	0.0%	0.0%	0.0%	0.0%
Infigen	0.0%	0.0%	0.0%	0.2%	0.2%
Infratil	0.0%	0.0%	0.0%	0.0%	0.0%
Intergen	0.0%	0.0%	0.0%	0.0%	0.0%
IP	0.0%	0.0%	0.0%	0.0%	0.0%
LoyYang	0.0%	0.0%	0.0%	0.0%	0.0%
MacGen	38.6%	34.8%	32.5%	38.9%	35.5%

Marubeni	1.4%	1.4%	1.4%	1.5%	1.5%
Origin	0.7%	2.5%	6.3%	18.6%	18.8%
PacHydro	0.0%	0.0%	0.0%	0.0%	0.0%
QGC	0.0%	0.0%	0.0%	0.0%	0.0%
RATCH	0.0%	0.0%	0.0%	0.0%	0.0%
Redbank	0.0%	0.0%	0.9%	1.5%	1.6%
Rio	0.0%	0.0%	0.0%	0.0%	0.0%
Roaring40s	0.0%	0.0%	0.0%	0.0%	0.0%
Snowy	5.9%	9.9%	8.6%	3.4%	4.6%
Stanwell	0.0%	0.0%	0.0%	0.0%	0.0%
Tarong	0.0%	0.0%	0.0%	0.0%	0.0%
Transfield	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Frontier Economics analysis of AEMO data

Table 22: Aggregate NSW pool revenue by portfolio ($m)

FY	2009	2010	2011	2012	2013
ACCIONA	0	0	1	4	8
AGL	0	0	0	0	0
Alcoa	0	0	0	0	0
Alinta	0	34	16	0	0
Arrow	0	0	0	0	0
Aurora	0	0	0	0	0
Babcock	26	7	0	0	0
Comalco	0	0	0	0	0
CS	0	0	0	0	0

Delta	996	1,124	824	185	425
EA	34	131	231	538	933
EnergyBrix	0	0	0	0	0
Eraring	614	633	413	7	12
Ergon	0	0	0	0	0
ERM	0	0	0	0	0
HydroTas	0	0	0	0	0
Infigen	0	0	0	4	8
Infratil	0	0	0	0	0
Intergen	0	0	0	0	0
IP	0	0	0	0	0
LoyYang	0	0	0	0	0
MacGen	1,211	1,305	958	799	1,298
Marubeni	45	53	42	31	56
Origin	23	95	187	382	686
PacHydro	0	0	0	0	0
QGC	0	0	0	0	0
RATCH	0	0	0	0	0
Redbank	0	0	27	31	59
Rio	0	0	0	0	0
Roaring40s	0	0	0	0	0
Snowy	185	372	253	70	169
Stanwell	0	0	0	0	0
Tarong	0	0	0	0	0
Transfield	0	0	0	0	0
Total	3,135	3,753	2,951	2,053	3,654

Source: Frontier Economics analysis of AEMO data

Contents

FRONTIER ECONOMICS | MELBOURNE | SYDNEY
Frontier Economics Pty Ltd 395 Collins Street Melbourne Victoria 3000
Tel: +61 (0)3 9620 4488 Fax: +61 (0)3 9620 4499 www.frontier-economics.com
ACN: 087 553 124 ABN: 13 087 553 124