Implications of high wind penetration for the NEM

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Abbreviations

AGC	Automatic generation control
AEMO	Australian Energy Market Operator
ERCOT	Electric Reliability Council of Texas
FCAS	Frequency Control Ancillary Services
IGT	Intermittent generation technology
MCP	Market Price Cap
NEM	National Electricity Market
NTNDP	National Transmission Network Development Plan
NWP	Numerical Weather Prediction
POE	Probability of exceedance
RET	Renewable Energy Target
SWIS	South West Interconnected System
VRET	Victorian 50% Renewable Energy Target
WEM	West Australian Electricity Wholesale Market

Executive summary

This paper explores the implications of increasing shares of intermittent renewable generation resources (IGRs) in the National Electricity Market (NEM) on the operating reserves that are needed to supply consumers with electricity in a reliable manner.

Integration costs of intermittent renewable generation resources

Various government policies that subsidise renewable generation, particularly the Renewable Energy Target (RET), have resulted in a substantial increase in large-scale renewable capacity in the NEM. The direct subsidies paid by electricity consumers to achieve the large-scale component of the RET are estimated at more than $1.8 billion in 2016 alone, but these subsidies only represent a fraction of the costs of this policy. Generation technologies that operate only intermittently additionally impose so-called 'hidden' or 'integration costs' on the remainder of the power system that are akin to a negative externality. These costs increase significantly as the share of intermittent generation capacity in a power system rises.

Generation from wind is the cheapest form of renewable generation, and new large-scale renewable generation capacity in the NEM has overwhelmingly taken that form. The power output of wind generators varies substantially – from zero to a plant's maximum capability – over timescales ranging from minutes to hours. That output is also very difficult to forecast with confidence over anything other than very short timeframes. A recent survey of wind integration costs accordingly identified high and increasing cost impacts resulting from intermittent wind generation in terms of the costs imposed on the remainder of the power system:

- System 'balancing' costs, which arise due to wind forecasting errors. Wind forecasting errors require more costly conventional generating plant to be dispatched than would otherwise be the case, and require additional operating reserves to be held to account for the increased uncertainty. A trend estimate across wind integration studies in thermal power systems suggests that wind balancing costs increase from a base of around $2.7/MWh) by around 8 ¢/MWh for each percentage point increase in the share of wind generation.
- System 'utilisation' (or back-up) costs, which arise due to the fluctuating output of wind. While the utilisation of conventional power stations falls as the share of wind increases, these plants remains essential for the reliable and secure operation of the power system, and their capacity must be maintained and paid for. The need to carry additional conventional generation capacity (or equivalent technologies, such as storage) to compensate for the intermittency of many renewable resources represents a significant cost to the system. In the short run, given the existing fleet of generation resources in a power system, utilisation costs increase from a base of

around zero by around $1/MWh for each percentage point increase in the share of wind generation.

Estimates of integration costs differ across power systems. The above estimates may underestimate the potential integration costs in the NEM, given that the NEM is less densely interconnected and therefore inherently less able to share generation capacity and reserves than is the case in many other power systems. Nonetheless, according to AEMO's most recent National Transmission Network Development Plan (NTNDP), the share of wind generation is expected to be around 5.7 per cent of NEM generation in 2016-17. On that basis, the balancing and utilisation costs imposed by wind generation on the non-intermittent part of the NEM system amount to around $8.9 per MWh of wind generated. Importantly, however, integration costs increase disproportionately as the share of intermittent generation increases. For a typical European thermal power system, for instance, total integration costs (including the costs of augmenting the transmission network) amount to upwards of $95/MWh when wind reaches a share of 40 per cent.

NEM investment incentives

The NEM Rules currently do not allocate integration costs to intermittent generators on the basis of causality. As of February 2017, AEMO reported installed wind generation capacity of 3,830 MW, of which 1,595 MW is located in South Australia. The observation that investment in renewable generation in the NEM consists entirely of intermittent technologies that impose the largest burden on the system is a reflection of the lack of such a cost attribution mechanism. Developers of large-scale intermittent generation projects do not internalise the costs they impose on the remainder of the power system (and eventually on consumers), and therefore have no incentive to minimise these by deploying suitable technologies, for instance by incorporating storage.

In the future, more than 14,000 MW of additional wind and solar generation projects are proposed in the NEM. Unless changes are made to the Rules to better align the incentives of developers with the additional system costs caused by generation that only operates intermittently, the overall costs of supplying consumers in the NEM with reliable electricity can be expected to increase substantially. Over the medium to longer term, and contrary to the NEM objective, consumers will be required to bear the cost of inefficient investment decisions.

Intermittent generation and system reserves

Of concern in power systems with high penetrations of wind is the occurrence of wind ramp events: large increases or decreases in the aggregate output of wind farms over a few hours. A power system is only secure (in the sense that there are no black-outs) if electricity generation continuously matches demand. Large down ramps that coincide with large increases in demand are therefore a challenge to the secure operation of a power system, and must be offset by conventional generators that must stand ready to generate. Such events are increasingly becoming an issue in South Australia, the NEM region with the highest share of renewables.

The variability and uncertainty of output – as reflected in the potential for large forecast errors – of IGRs requires power systems to hold additional operating reserves to ensure that demand can be met continuously. The detailed wind studies that have been undertaken in US power markets consistently indicate that reserve requirements increase over all operational timescales as the share of intermittent generation increases.

All power systems, including the NEM, deploy 'regulation' (reserve) services to balance demand and supply over timeframes of seconds and minutes. Regulation services can generally continue to be used to manage the additional variability introduced by fluctuations in the output of intermittent generators. However, when the share of intermittent generation in a power system becomes larger, regulation requirements increase, sometimes significantly so. The Australian Energy Market Operator (AEMO) also projects that regulation requirements will become greater in the NEM, particularly in South Australia.

Further, additional flexible conventional generation capacity is needed to compensate for rapid changes in the aggregate output of intermittent generators when these coincide with increases in demand. These types of ramp events are difficult to forecast reliably, so that flexible plants may not be available to generate and avoid temporary price spikes. System operators in other liberalised power markets have correspondingly identified a need for 'ramp reserves' to mitigate against the system security and price implications of large wind ramps. In ERCOT, for example, which has a similar market design as the NEM, slower 30-minute reserves are now called upon to stand available to address wind ramp events.

NEM investment incentives and minimising system costs

In today's power systems (and in the NEM), the great majority of reserves are provided by conventional generating plants. That conventional generation capacity increasingly becomes underutilised as the share of intermittent renewable generation grows, but must nonetheless be maintained and paid for. The NEM Rules do not provide for a consistent framework to attribute the costs of additional reserves to intermittent plants whose production patterns require these reserves to be held:

- While some share of regulation costs are currently attributed to 'semi-scheduled' (intermittent) generators, the cost allocation methodology is not aligned with the underlying cost drivers of regulation services: the extent to which (intermittent) generators contribute to the variability and uncertainty of demand.
- The question of how the conventional flexible generation capacity that is needed to manage large changes in the output of intermittent plants or situations where intermittent output is low or zero will be incentivised and paid, and who should bear these costs remains unresolved.

Investors in large-scale intermittent power stations therefore do not internalise these costs, and have no incentive to invest in technologies that would minimise the need for additional reserves. As a consequence, investment in renewable generation in the NEM to date consists entirely of intermittent technologies that impose the largest costs on the remainder of the power system, including in terms of the additional reserves that are needed. Over a longer timeframe, these costs will invariably be borne by consumers.

In future, allocating at least some share of integration costs to the market participants who cause them will be fundamental to incentivising efficient investment and for ensuring that the overall system costs in the NEM are minimised, in the interests of consumers. At a minimum, aligning the incentives of investors in intermittent generation projects with the objective of minimising system costs would require allocating the costs of regulation based on causality; that is, the extent to which (intermittent) generators cause higher regulation costs to be incurred.

The more important concern is how to ensure that investors in intermittent generation projects internalise the costs of the additional reserves that are needed to cope with large swings in output, such that system costs are minimised. A number of high-level options could be considered for achieving this objective.

Minimum performance standards

One option would be to establish certain minimum performance standards that must be met by intermittent generators, for instance, in terms of a percentage of registered capacity that must be 'firm' (guaranteed to be physically available). In effect, such a requirement would require each intermittent generator to provide at least some share of the back-up capacity required by the system when that generator's output is low or zero. A requirement for a minimum level of firm capacity may deliver at least a minimum level of reliable output from intermittent plants, and would allocate the cost of procuring that reliable output to these plants. However, given the existence of scale and scope economies in generation and reserves services, this option is unlikely to minimise overall system costs.

Network investment

AEMO's National Transmission Network Development Plan describes an extensive and very costly transmission investment program across the Eastern Seaboard grid to accommodate new intermittent generation. Among other things, these augmentations would enable better reserve sharing across the NEM. However, under the NEM Rules, the costs of investments in the shared network would simply be allocated to consumers. This option is then particularly costly, because it offers no incentives to intermittent generators, whose operational patterns (and locational decisions) give rise to these costs, to minimise them.

Capacity payments

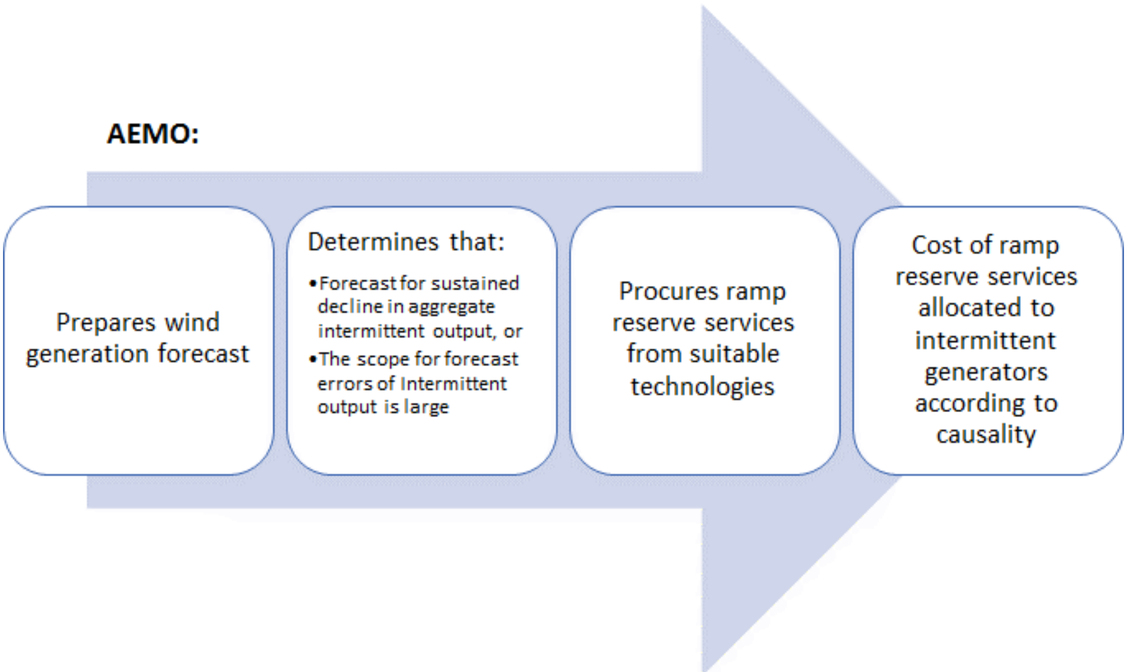
Alternatively, some form of capacity payment system could be introduced to provide an additional financial incentive to conventional generators who are required to maintain system security and reliability. Such capacity payments would eliminate the need for a very high (and likely increasing) Market Price Cap, and may be needed at some point in the future. However, this option would represent a major change to the NEM market design, and would be complex and costly to design and implement. Additionally, and while intermittent generators would inherently receive a low (and declining) capacity credit, any efficient investment signals would be muted because those imposing the externality have no direct incentive to internalise it.

Ramping ancillary service

The option that is recommended in this report is to expand the scope of ancillary (reserve) services that are currently defined in the NEM. The proposed 'ramp reserve' ancillary service would specifically address rapid downswings in wind output that are difficult to forecast, that challenge generator response times, and that give rise to corresponding price spikes. The costs of this service would be attributed to the market participants whose intermittent output causes these reserves to be called. Allocating the corresponding costs to IGRs would incentivise intermittent plants to invest in the technologies to reduce output variations and improve predictability, thereby reducing the additional reserves that are needed. At the same time, payments for flexible generation services would support the aim of ensuring that this type of conventional capacity remains available in the NEM.

The proposed ramp reserve service represents an incremental market design change, but does not address the longer-term problem that conventional generation may no longer be viable in a market increasingly dominated by intermittent generation. Figure A illustrates the basic principle of the proposal. AEMO would, in the normal course of events review its wind generation forecast and determine whether there is a significant likelihood of a sustained decline in aggregate wind output, or whether the uncertainty around the wind output forecast is particularly large. Similar to an insurance policy, AEMO would then call for bids for ramp reserve and enable suitable flexible technologies to be on standby to respond in the event that aggregate wind output falls in a sustained manner. If such an event materialised, sufficiently flexible conventional generation (or other suitable technologies) would be available to meet consumer demand.

Figure A. Deployment of ramp reserve ancillary service



Given that payments for the ramp reserve service would be recovered from intermittent generators, there would be limited net price impact on consumers. Furthermore, given that the provision of this service may avoid the price spikes that frequently occur in the context of large wind down ramp events, average prices may be reduced. It is important to note that the introduction of this service would be targeted at specific circumstances where there is material uncertainty about the output of intermittent generators. As such, the role of high NEM prices as a broader indicator of generation capacity shortages would not be affected.

1 Introduction

This paper explores the implications of increasing shares of intermittent renewable generation resources (IGRs), specifically generation from wind, on the operating reserves that are needed for system security in the National Electricity Market (NEM).

1.1 Integration costs of intermittent renewables

Various government policies that subsidise renewable generation, particularly the Renewable Energy Target (RET), but also discounted finance via the Clean Energy Finance Corporation and direct grants from the Australian Renewable Energy Agency, have resulted in a substantial increase in large-scale renewable generation capacity in the NEM. The direct subsidies paid by electricity consumers to achieve the large-scale component of the RET are estimated at more than $1.8 billion in 2016 alone, but these subsidies only represent part of the costs of this policy. Intermittent generation technologies impose a range of additional costs on the remainder of the power system. A key aspect of these 'integration' costs relates to the variability and unpredictability of the output of IGRs, which requires systems to hold additional operating reserves to maintain system security.

The implications of higher shares of intermittent generation for reserves in the NEM or how the corresponding costs should be allocated and recovered has received limited public attention. Specifically, there is currently no overarching framework to allocate the costs of reserves to the market participants that require these to be held, so that these costs are not internalised by developers of large-scale renewable generation projects. Intermittent generators currently pay some share of the costs of reserves to balance the system over very short-term timeframes, but the allocation method that is applied is unlikely to be cost-reflective. The challenge of retaining sufficient flexible reserves to cope with situations where aggregate intermittent generation declines precipitously over a matter of hours, and how the corresponding costs should be recovered has not been addressed to date. Overall, investors in renewable generation projects therefore have little, if any, incentive to minimise integration costs, including in terms of the additional reserves needed to ensure the ongoing reliable supply of electricity to consumers.

The share of intermittent large-scale wind and solar generation is expected to increase substantially in the future. In the absence of a framework in which the additional reserve requirements are identified and the corresponding costs allocated to those IGRs who cause them, there can be no expectation that developers will internalise the costs and deploy technologies that reduce them. Contrary to the NEM Objective, consumers will then be required to bear the cost of inefficient investment decisions.

1.2 About this paper

This paper is structured as follows:

- Section 2 describes the characteristics of intermittent technologies and the nature of the corresponding integration costs in the non-intermittent part of the power system;

- Section 3 discusses the additional operating reserve requirements that arise because of the variability and uncertainty of intermittent technologies; and
- Section 4 discusses the implications for the NEM.

Additional supporting information is contained in two appendices:

- Appendix A presents a number of graphs to illustrate the output of intermittent power stations;
- Appendix B describes different types of 'ramp' reserve services that have been introduced in US power markets.

2 Characteristics and integration costs of intermittent generation resources

This section describes the characteristics of intermittent generation resources and the corresponding integration costs they give rise to in the non-intermittent part of the power system. The focus is particularly on wind, given that the largest share of large-scale renewable generation investment in the NEM has taken the form of wind generation:

- Section 2.1 discusses the variability and uncertainty that characterises the output of IGRs; and
- Section 2.2 outlines the corresponding integration costs that arise in the power system.

2.1 Intermittent generation technologies

Wind and solar PV technologies operate in a manner that is fundamentally different to that of 'conventional' generation technologies, such as coal or gas. Conventional generation technologies can be controlled, or 'dispatched' to a defined output level. The electrical output of many renewable generation technologies, on the other hand, fluctuates or is 'intermittent'; that is, energy sources such as wind and sun are not continuously available to generate a known quantity of electricity due to external factors that cannot be controlled. There are therefore significant limitations in the extent to which IGRs can be dispatched by the system operator, and the extent to which they can usefully be deployed to exactly match or 'balance' electricity demand. While the focus here is specifically on wind as a renewable energy source, generation from solar PV facilities has many of the same characteristics (Arvizu et al. 2011).

2.1.1 Variability of wind generation

The electrical output of a wind turbine fluctuates over different timescales that are relevant for power system operations. This variability, as measured by the standard deviation of output, increases the response requirements from conventional generators and responsive load.

The electrical output of a wind turbine depends on the wind speed, which depends on regional weather patterns and the surrounding landscape and terrain (Soman et al. 2010, Wiser et al. 2011). Variations in output occur over multiple time scales, ranging from very short-term fluctuations to diurnal, seasonal and inter-annual fluctuations, and their patterns are highly site- and region-specific. In South Australia, which has the highest penetration of renewables in the NEM, generation from wind displays a clear seasonal pattern, with the highest output generally occurring during the winter months, while prominent heatwaves cause a significant decline in monthly output (AEMO 2011).

The output of individual wind turbines fluctuates with wind turbulence and gusts. Over short timeframes, these variations may be independent and are smoothed as increasing numbers of turbines are deployed over a larger geographical area. However, similar wind conditions will eventually sweep over entire windfarms or groups of windfarms (Wan 2004, Holttinen et al. 2008). As the timeframe extends from hourly to daily, the influence of longer-term weather movements begins to dominate the output of wind turbines. Over such timeframes, the output of multiple wind turbines is correlated, with the correlation a function of the distance separating wind plants.

Wind ramp events

Over timeframes of one to many hours, step changes in the aggregate output of wind turbines are observed that are larger than output changes over short timeframes, and that can be substantial. So-called 'wind ramp events' – large increases or decreases in wind power within a defined limited time window – must be offset by the non-intermittent power system, either by decreasing or increasing the dispatch of conventional generators. There is no standard formal definition of what constitutes a wind ramp event, but in practice such ramps are defined by their direction, duration and magnitude (Ferreira et al. 2011). Up ramps are caused by increases in wind power, for instance resulting from intense low-pressure systems or thunderstorms. Down ramps occur when these processes are reversed, but also when high winds cause turbines to cut out suddenly.[1]

The variability of wind power can pose significant challenges to system operations within a current to 6-hour timeframe. Large wind ramp events are similar to conventional system contingencies (such as a large generator or load trip) in that they can be very large, but they differ in that they tend to occur more slowly and last longer (Ela 2011). Downward wind ramps must be met by increasing the output of conventional generators, and may pose a threat to system security if reserve generation is not available. When wind power decreases simultaneously with an increase in load, this effect is exacerbated. Finally, and although the probability of calm wind at every wind farm declines if wind farms are scattered over large geographical areas, such an event is still possible so that conventional generation capacity continues to be required even when more and more wind capacity is deployed.

The experience in other power systems is that the absolute magnitude of large wind ramp events increases with the penetration of wind generation in the grid. In the Electric Reliability Council of Texas (ERCOT) market, which has the highest share of wind generation in the United States, for instance, the number of large ramp events remained fairly constant between 2004 and 2009, but the magnitudes of the largest ramp events

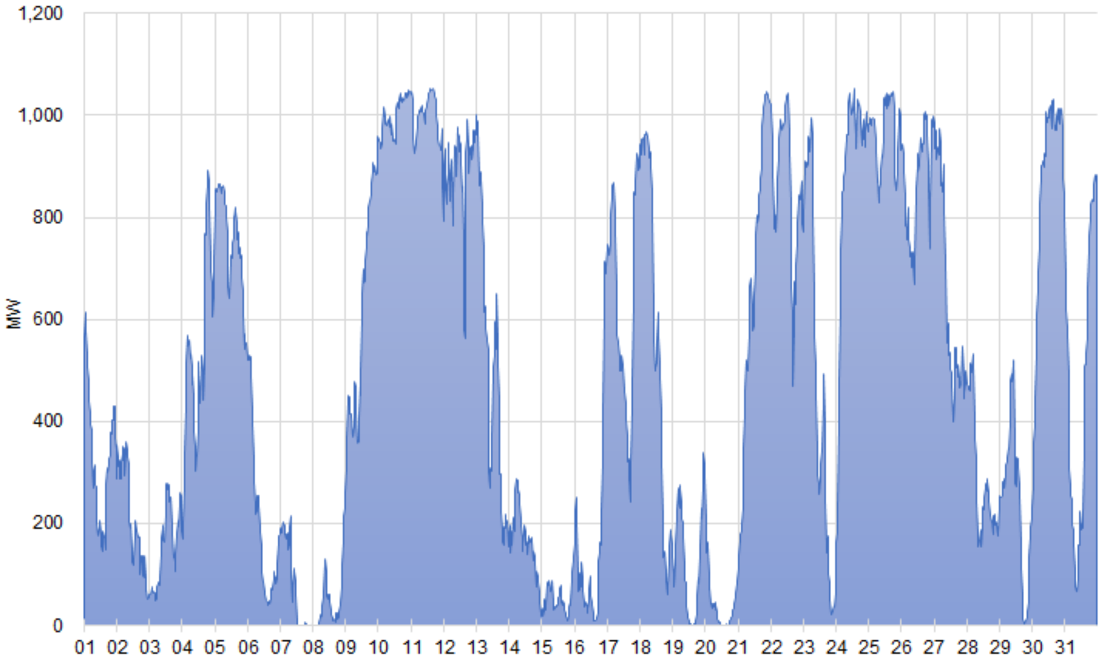
[1] High-speed winds are often experienced during adverse weather conditions, which generally impose operational stress conditions on electrical powers systems. Large uncontrolled variations in output from wind farms during such conditions add to the task of managing a secure system.

rose markedly (Wan 2011). A single large up or down ramp could last more than half a day with a magnitude of 75 per cent of the total installed wind capacity, and involving ramp rates from -468 MW/hour to +419 MW/hour.

South Australia

The existence and severity of large wind ramp events can be gauged from Figure 2-1, which shows wind generation in South Australia in July 2016. Over that month, wind generation exceeded 1,000 MW several times, but was also zero over many dispatch intervals on July 7 and 8, and on July 19 and 20.[2]

Figure 2-1. Wind generation in South Australia, July 2016



Notes: Figure A-1 in Appendix A shows wind generation in South Australia over the second half of 2016 for comparative purposes.

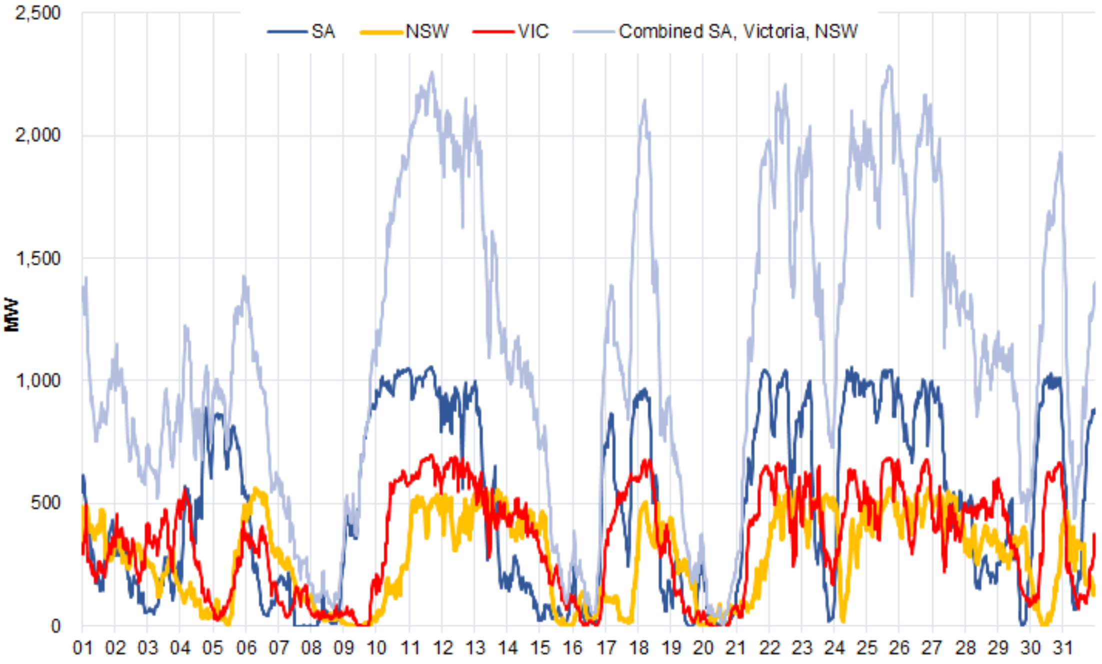
Source: AEMO data.

Figure 2-2 shows wind generation individually and combined for the South Australian, Victorian and NSW regions over the same timeframe (July 2016). Figure 2-2 highlights that, notwithstanding the large distances between the many wind farms operating in these regions of the NEM and the corresponding geographic diversity, aggregate wind

[2] Figure A-1 in Appendix A shows the output of the three largest solar generation plant on the East Coast in December 2016. Solar generation inherently displays a daily ramping pattern, albeit one that is more predictable. There are nonetheless considerable daily and hourly output variations.

output appears to have followed broadly similar trends. In particular, aggregate wind generation was less than 50MW over multiple trading intervals on July 20th.

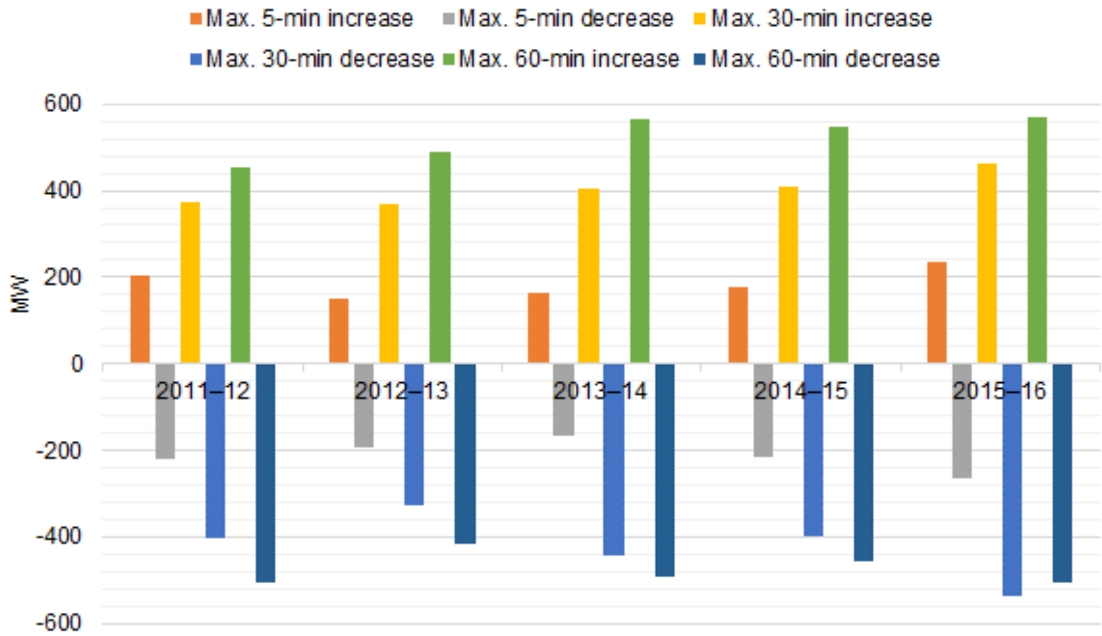
Figure 2-2. Wind generation on the Eastern Seaboard, July 2016



Source: AEMO data.

Figure 2-3 shows another aspect of South Australian wind generation that is also indicative of large ramp events: the significant rates of change in wind output over timeframes from five-, to 30-, and 60-minutes. Figure 2-3 shows that the maximum increase in wind output over an hour amounted to 571MW (39 per cent of registered wind capacity in South Australia), while the maximum decrease in wind output was -506MW (34 per cent of registered wind capacity). Rapid changes in wind output over short timeframes represent a challenge for the power system since conventional generators must be deployed rapidly to compensate for these variations.

Figure 2-3. South Australian wind generation – Maximum output variation (MW)



Source: AEMO 2016.

2.1.2 Uncertainty of wind generation

The variability of wind generation – in terms of the large swings in output – implies that conventional generation needs to be held in reserve in power systems with large shares of wind generation. That requirement is reinforced by the increased uncertainty that wind capacity presents to the system because the output of wind farms is difficult to forecast, particularly over longer timeframes. Operating a power system securely therefore requires additional operating reserves to be held to account for the potential for large wind forecast errors.

Wind and wind generation forecasting

Wind and wind generation forecasting is a large and complex field (Foley et al. 2012; Soman et al. 2010; Chang 2014; Jung and Broadwater 2014). Wind and the output of wind turbines is uncertain over multiple timescales, from very short-term (a few seconds to 30 minutes), short-term (30 minutes to 6 hours), medium-term (6 to 24 hours), and long-term (1 to 7 days). Each timescale requires a specific modelling approach. Wind power forecasting models developed for one location are not useful for other locations due to terrain changes, different wind speed patterns, and different atmospheric factors such as temperature, pressure and humidity.

Very short and short-term forecasting models usually rely on the 'persistence' method, which essentially assumes that wind output at time t is the same as at time t-1. Physical models that predict wind output over hours and days rely on Numerical Weather Prediction (NWP) models that forecast atmospheric dynamics, but which are also very data and time intensive to run. These models translate a wind forecast into power output by first, determining wind speed and direction from a model, next, downscaling the NWP data to calculate wind power output based on such factors as terrain, the hub height of a turbine and the wind farm layout, and, third, upscaling the results to derive a regional forecast over some given time horizons. Other types of approaches rely on statistical (time-series) models, spatial correlation models, and artificial intelligence methods. Hybrid approaches may combine any of these.

Wind output forecasting errors

Wind and wind power forecast errors challenge the operation of power systems. While the electrical output of a wind turbine depends on wind speed, that relationship is nonlinear and cubic (Soman et al. 2010). An error in the wind speed forecast therefore results in a large (cubic) wind power error, and can generate a correspondingly larger error in the wind power forecast. In addition, the relationship between wind and wind power output becomes more complex as more wind turbines are added. Positive correlation between individual wind farms' forecast errors is an important issue and significantly increases the overall variability of output and therefore the uncertainty that the system is exposed to from wind capacity. For multiple wind farms, wind output forecast errors are related to the accuracy of forecasts for individual wind farms, the correlation of forecast errors between different wind farms, the forecast horizon, and the geographical dispersion of wind farms.

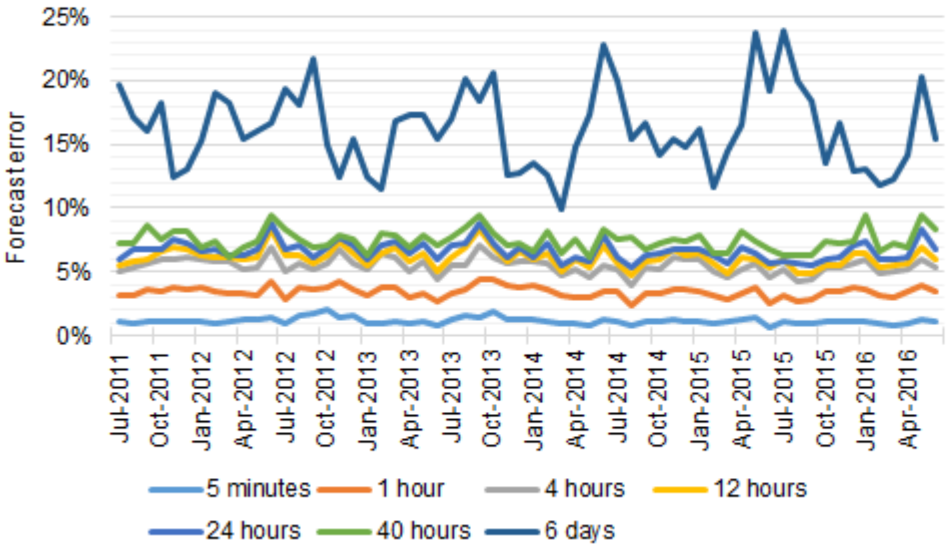
Wind output forecast errors increase with the length of the forecasting horizon. While wind power can be reasonably accurately predicted over short timeframes of minutes, the forecast errors for longer time periods tend to be many times higher, and may tax the ability of the system to respond to large (unexpected) wind power variations (Milligan et al. 2015). The relationship between the time horizon and the magnitude of forecasting errors can approximately be seen in Figure 2-4, which shows the normalised mean absolute percentage errors generated by the Australian Wind Energy Forecasting System (AWEFS) for South Australian wind output.[3] Figure 2-4 shows that:

- while average wind forecast errors over a five-minute dispatch interval are about 1.2 per cent of (wind) capacity, average forecasting errors increase noticeably over longer forecasting horizons; and
- there is no discernible downward trend to indicate that wind output forecasting errors in percentage terms have declined over the past five years.

The latter point implies that, as wind generation capacity in South Australia has increased in recent years, the wind generation forecast error has also increased in absolute terms.

[3] The normalised mean absolute error of the forecast is the absolute difference between forecast and actual output, divided by the nominal capacity. This error metric gives equal weight to large and small errors which leads to poor comparisons and selections of forecasting models in circumstances where the key concern relates to large absolute (forecasting) errors.

Figure 2-4. Normalised mean absolute error of AWEFS forecasts for South Australia from FY12 to FY16



Source: AEMO 2016.

A comparison of wind forecasting errors across six countries similarly showed that, regardless of country, forecasting period, or amount of installed wind capacity, wind output forecast errors, while more concentrated about the mean than is the case for a normal distribution, have fat tails indicating the frequency of very large relative forecast errors (Hodge et al. 2012).[4]

The spread of the distribution of forecast errors will, for models with similar levels of forecasting skill, reflect the variability of changes in wind output over the forecast horizon. Variability depends on the scale or capacity of wind generation and the spatial correlation in wind speed between the location of wind farms. In general, positive spatial correlation increases with proximity and greater dispersion will tend to reduce variability. In South Australia wind farms are located in clusters with a high density of turbines in smaller areas. In 2016, the standard deviation of wind generation in South Australia was 70 per cent higher than in NSW where wind farms are more spread out. However, the scale of weather systems can still impose significant correlations over large geographic areas.

[4] Error distributions with fat tails can occur for several reasons. One is the use of absolute errors to select a model, as opposed to squared errors which gives greater weight to large errors. Another is that the distribution of the change in wind speed over the forecast horizon has fat tails. However, the fatness of the tail, as measured by the kurtosis, is of secondary importance relative to the spread of the distribution as measured by the standard deviation. Over 2016, in South Australia the kurtosis of the difference in five-minute wind generation was ten times greater than for 30-minute intervals. Over the same period the standard deviation in wind generation between 30-minute intervals was three times greater than for five minute intervals.

Forecasting wind ramp events

As the penetration of renewables has increased, predicting large wind ramp events is becoming increasingly critical to managing power system security. Forecasting a wind ramp event requires forecasting the timing of the event with a reasonable degree of reliability, its magnitude, and its location, all of which pose formidable challenges (Ferreira et al. 2011).

An acceptable degree of reliability is not simply a statistical measure. As the occurrence of a ramp event is a discrete event, there are four types of forecast outcomes:

- a successful prediction of an event that occurred;
- a failed prediction of an event that occurred;
- a false prediction of an event that did not occur; and
- a successful prediction of an event that did not occur.

If the cost of responding to a false positive is small compared to the failure to predict an event (for instance, if there are real risks to system security), a model that catches most of the events but gives many false alarms can be useful. However, the cumulative costs of a large number of false alarms may render the same forecasting model useless.

Furthermore, forecasting the magnitude of a wind ramp event is conditional on the occurrence of that event. Events that only occur infrequently often do no provide much information about the distribution of the magnitude of an event when it occurs. Hence, it can be difficult to say anything meaningful about the probability of a large ramp event occurring.[5] Ferreira et al. (2011) therefore conclude that the stochastic nature of ramp events makes it almost impossible to generate reliable forecasts for timeframes longer than 48 hours ahead.

2.2 System integration costs

The variability and uncertainty of the electrical output of IGRs gives rise to 'hidden' or 'integration' costs that fall on the non-intermittent part of the power system (Hirth et al. 2014, Hirth et al. 2015, and Ueckerdt et al. 2013). The concept of integration costs of a specific generation technology captures the effect that deploying that technology causes costs elsewhere in the power system. While these costs in principle arise for all types of generation technologies, what distinguishes the integration costs of intermittent technologies is not their existence, but their size (Hirth et al. 2016). Because of their variability and unpredictability implied by large forecast errors, intermittent generation resources such as wind interact differently with the power system than is the case for conventional plants that can be dispatched. The increasing deployment of IGRs implies

[5] However, the size of a wind ramp event is to some extent constrained by the wind generation capacity, which may provide the basis for a precautionary strategy for managing a predicted event.

that specific actions need to be taken – and corresponding costs incurred – in other parts of the power system. Integration costs are then defined as all additional costs in the non-intermittent part of the power system when IGR resources are deployed (Ueckerdt et al. 2013).

The focus in this paper is on those aspects of integration costs that relate to the need for power systems to hold additional operating reserves, namely:

- balancing costs, which occur because the supply from IGRs is uncertain until realisation and forecasting errors therefore arise; and
- profile costs, which are caused by the variability and intertemporal generation profile of IGR technologies.

Other forms of integration costs are not discussed in this paper.[6] They include grid costs, which arise because (high quality) renewable energy sources are often located remotely from demand (load) centres and significant network investment is then required to transfer IGR power output to loads. The combination of a rising share of IGRs and the withdrawal of conventional power stations that is also apparent in the NEM furthermore creates a range of operational challenges to power system operations, including from a lack of 'inertia' which reduces the ability of a power system to securely 'ride through' fault events.

2.2.1 Balancing costs

Balancing costs result from errors in forecasting the output of IGRs. Forecast errors have two consequences. First, they require adjustments to be made to the planned dispatch schedule of conventional power stations to compensate for unexpected variations in, say, wind output. Adjustments to planned dispatch schedules are costly if more expensive conventional plants must be dispatched than would have been the case under perfect foresight. Second, forecast errors require additional operating reserves to be held to respond to unexpected variations in wind output.

2.2.2 Profile costs

Profile costs arise because of the variability and large temporal variations in the output of intermittent generators. Whereas balancing costs are a consequence of forecasting errors, profile costs would occur even if the output of intermittent resources could be predicted perfectly. They arise because while IGRs contribute some electricity to meet demand, they hardly reduce the need for generation capacity in a power system (Ueckerdt et al. 2013). Supply and demand in a power system must be balanced at all

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[6] For a more detailed exposition, see Fisher, Brian S., and Sabine Schnittger, 2016.Implications of Australian Renewable Energy Mandates for the Electricity Sector, BAE Research Report 2016.2; at: http://www.baeconomics.com.au/publications.

times, so that sufficient generation capacity must be available to reliably supply consumers when intermittent output is low. Generating capacity is very costly, and the profile costs of IGRs are therefore more material than balancing costs.

Profile costs have a number of components.[7] The 'flexibility' component of profile costs reflects the specific operational requirements placed on conventional generators, such as frequent ramping or cycling whereby conventional power stations must adjust their output in response to steep changes in wind output. Flexibility costs are reflected in increased wear and tear on capital equipment and reduced efficiency of thermal generators.

The 'utilisation' or 'back-up' cost component of profile costs arise because significant (conventional) reserves are needed even at high rates of IGR penetration. These costs arise because the output of intermittent generators is often not well correlated with demand. IGRs such as wind and solar, which incur no fuel costs, are always 'dispatched' before conventional generators. Rising shares of IGRs in a power system therefore reduce the amount of electricity generated by conventional generators. The utilisation (or capacity factor) of conventional dispatchable generators then declines, and the annual and life-cycle cost per unit of capacity of conventional generation and of the residual power system more generally increases. The key point is that while the utilisation of conventional power stations falls, the capacity (or capability to generate) of these plants remains essential for the reliable and secure operation of the power system, and must be maintained and paid for. The need to carry additional conventional generation capacity (or equivalent technologies, such as storage) to compensate for the intermittency of many renewable resources represents a significant cost to the system.

The intertemporal generation profile of wind generators is reflected in the low capacity credit that is generally assigned to these technologies in long-term reliability studies (Wiser et al. 2011).[8] Wind turbines are typically found to have a capacity credit of 5 to 40 per cent of their nameplate capacity, since their output is often uncorrelated or weakly negatively correlated with periods of high electricity demand. Furthermore, capacity credits for wind energy generally decrease as wind electricity penetration levels rise, because the output of multiple wind turbines is (positively) correlated. Systems with large amounts of wind capacity therefore need to hold significantly more capacity in reserve to meet the same peak electricity demand than electric systems without large amounts of wind energy. Much of this generation capacity will operate only infrequently, but its costs must still be incurred by the system and therefore by consumers.

The ability of generation from wind to reliably meet demand is similarly limited in the NEM. In South Australia, wind generation has a distinct daily profile that increases

[7] Other components of profile costs include overproduction costs, which occur because, at higher penetrations, IGTs produce more electricity than is demanded by consumers and that output has to be curtailed or 'spilled'.

[8] The capacity credit of a generation resource is the amount of additional demand that can be served if the generator is added to the system while maintaining existing levels of reliability.

overnight from around 10.00 PM through to 6.00 AM the next day, and peaks from around 3.00 AM to 5.00 AM when average demand is at its lowest (AEMO 2016). Wind generation then tends to fall as demand ramps up for the morning peak. Table 2-1 shows the shares of registered wind capacity that is expected to be available at least 85 per cent of the time during the top 10 per cent of demand periods in those NEM regions with wind generation. For example, the expected contribution of wind in South Australia during the summer months is 9.4 per cent of wind capacity, and 7.0 per cent of capacity in the winter months. The implication is that wind generation generally meets less than 10 per cent of demand when consumers require it most.

Table 2-1. Expected wind contribution during peak demand (Per cent of registered wind capacity)

	New South Wales	Victoria	South Australia	Tasmania
Five-year summer average	3.0%	7.5%	9.4%	8.5%
Five-year winter average	4.2%	6.8%	7.0%	4.9%

Source: AEMO 2016.

2.2.3 Integration cost estimates

Balancing costs

The challenges associated with balancing unexpected variations in the output of IGRs increase with the penetration of renewables in a power system, and are greatest within a one- to six-hour timeframe and in small systems. Many studies that estimate the balancing costs of IGRs focus on one particular aspect of these costs; for instance, by considering only certain types of reserves and not changes to planned dispatch schedules. Nonetheless, the apparent consensus in the literature is that the balancing costs of IGRs are relatively small compared to profile costs. Most estimates of balancing costs are below about 6 €/MWh (AU$ 8/MWh) of wind energy generated even at higher wind penetration rates (Hirth et al. 2015). Hirth et al. (2015) report that a fitted trend line indicates that for each percentage point in penetration, the balancing costs of wind power increase by €0.06/MWh (AU$ 0.08/MWh), so that balancing costs increase from €2/MWh (AU$ 2.7/MWh) to €4/MWh (AU$ 5.3/MWh) as wind penetration increases from zero to 40 per cent.

In Australia, Riesz et al. (2011) estimated the additional balancing costs in the NEM and the West Australian Electricity Wholesale Market (WEM) for a 20 per cent RET target (but not the additional costs arising from deviations from planned generation schedules). In the NEM, AEMO calls on Frequency Control Ancillary Services (FCAS) for short-term balancing services, including 'Regulation Raise' and 'Regulation Lower' services. The corresponding WEM regulation service is called 'Load Following'. Riesz et al. found that in the NEM, the Regulation requirement would increase by around 10 per cent of the added wind capacity. In the much smaller South West Interconnected System (SWIS), the Load Following requirement would increase by around 30-40 per cent of the added wind capacity. The high additional reserve requirement in the SWIS reflects the large size of a new wind farm relative to the size of the SWIS, and the fact that the output of wind farms in the SWIS is highly correlated, leading in turn to larger 'disturbances' relative to the size of the system. While relatively small as a percentage of total system costs, Riesz et al. concluded that if the additional load following costs were allocated to wind generators, they would amount to AU$ 8.30/MWh of wind energy generated in the NEM, and to $29.17/MWh of wind energy generated in the WEM.

Profile costs

Hirth et al. (2015) analyse wind profile cost estimates from some 30 publications.[9] If it is assumed that changes are made to the capacity mix by retiring existing plant and investing in more flexible generation capacity, wind profile costs are estimated to be zero or slightly negative at low penetration rates, and to be around €15 to €25 (AU$ 20 to $33.3) per MWh at penetration rates in the 30 to 40 per cent range. A fitted trend line indicates that even in such a long-term adaptation scenario, the profile cost of wind power increase by €0.5 (AU$ 0.67) per MWh generated for each percentage point increase in wind penetration. In contrast, if it is assumed that the generation mix remains unchanged, profile costs are 50 per cent higher, or €0.75 (AU$ 1) per MWh generated.

Combined integration costs

The components that constitute the integration costs of IGRs – balancing, profile and grid-related costs - are not constant parameters, but are functions of many system properties (Hirth et al. 2016). A general literature review suggests that integration costs become very high when IGRs account for a large share of generation, in the range of 25 – 35 €/MWh (AU$ 33.3 to AU$ 46.7/MWh).

Furthermore, integration costs also tend to be higher in predominantly thermal power systems (like the NEM). Ueckerdt et al. (2013) analyse wind integration costs in European thermal power systems. They find that when the share of wind generation is 20 per cent, short-term integration costs are upwards of 45 €/MWh (AU$ 60/MWh), and that these costs amount to around 72 €/MWh (AU$ 96 /MWh) when the share of wind generation is 40 per cent.

These issues are discussed in detail in Fisher and Schnittger (2016).

2.3 Conclusions

The power output of IGRs varies over timescales from minutes to hours, and is very difficult to forecast with confidence. These variations in wind output must be offset by conventional generation that must be available to operate. Of particular concern in power systems with high penetrations of wind is the occurrence of wind ramp events that represent large increases or decreases in the aggregate output of wind farms over a few hours. Large down ramps that coincide with large increases in demand are a challenge to

[9] Many of the studies cited only report estimates of the utilisation effect. As such these estimates are likely to underestimate total profile costs.

the secure operation of a power system. Such events must be offset by the non-intermittent power system by increasing the dispatch of available conventional generators.

The variability and uncertainty of output (in terms of the potential for large forecast errors) of IGRs requires power systems to hold more operating reserves to ensure that demand can be met at all times. In today's power systems (and in the NEM), operating reserves are provided by conventional generation capacity. That conventional generation capacity increasingly becomes underutilised as the penetration of renewables increases over time, but must nonetheless be maintained and paid for. At the same time, the NEM Rules do not provide for a consistent framework to attribute the costs of any increased reserves to intermittent generators whose production patterns require these reserves to be held. Investors of large-scale intermittent power stations therefore do not internalise these costs, and have little or no incentive to minimise them, for instance, by locating at a larger distance from other wind farms or by incorporating some form of storage technologies. Over a longer timeframe, the overall system costs of reliably supplying consumers with electricity will rise, and those costs will be borne by consumers.

3 Intermittent generation and operating reserves

Power systems hold reserves to protect against an uncertain future. Historically, the types and quantities of reserves were set based on the variability and prediction errors of load, and to cope with sudden unexpected events such as a large generation or transmission outage. When intermittent generating plants are added to a power system, the inherent variability and unpredictability of IGR output is combined with the variability and prediction errors of system load (demand).

This section discusses the implications of higher shares of intermittent generation technologies for operating reserves over multiple timescales:

- Section 3.1 describes the concept of 'residual' demand that must be matched by conventional generation;
- Section 3.2 describes two key types of operating reserves that are deployed in all power systems; and
- Section 3.3 describes the implications of higher shares of IGRs for operating reserves.

3.1 Balancing residual demand

In any power system, generation must match demand as closely as possible so that the system frequency is maintained within its normal operating band.[10] 'Operating reserves' above what is needed to match demand are therefore needed – either on-line (spinning) or on standby (fast start) – so that these reserves can be called on to assist if load increases or generation decreases (Ela et al. 2011). Likewise, on-line generating capacity is needed that is positioned to reduce supply or turn off if load decreases or generation increases.

To understand the consequences of a greater share of intermittent generation resources for operating reserves, it is necessary to refer to the concept of 'residual' demand or load. The output of intermittent technologies such as wind and PV solar, on the one hand, and consumers' variable demand for electricity, on the other, share some common characteristics (GE Energy 2008). Both are subject to cyclical seasonal and daily trends, both display random short-term variations around trends lasting multiple hours, both are subject to forecasting errors (although these errors are more

[10] System frequency is a fundamental indicator of power system health (Kirby 2007), and can be likened to the heartbeat of a power system – a beat that is too fast or too slow can result in system collapse. Frequency falls when load exceeds generation and rises when generation exceeds load. Large frequency deviations result in equipment damage and eventually the collapse of the power system.

material for wind output than for load), and both are mutually dependent on prevailing weather conditions.[11] Also, neither IGRs nor loads are dispatchable, that is, controllable. In some respects, wind generation therefore has more in common with load than it has with conventional dispatchable generation resources, the only difference being one of sign: wind acts like a negative load. For system operators who can only control the output of conventional dispatchable power stations, but not the output of intermittent renewables, the consequence is that the output of conventional generators must match the 'net' or 'residual' load: the difference between aggregate system demand and the output of intermittent (wind and solar) generation resources.

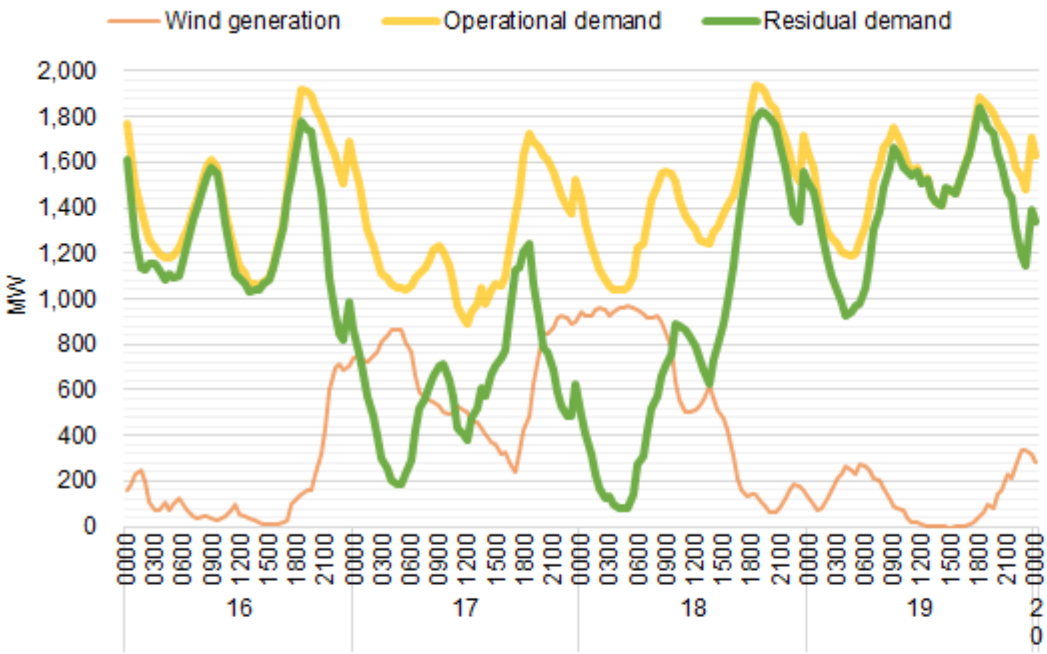
The need to deploy additional operating reserves then depends on the variability and unpredictability of the residual load. Load forecasts also have an error associated with them. However, due to the highly repetitive nature of the daily load profile, load forecast errors are not especially sensitive to the forecast horizon, and are usually proportional to the size of the load at any given hour (Doherty O'Malley 2005). In contrast, wind power forecast errors generally increase as the forecasting horizon increases. With a longer forecasting horizon, the standard deviation of the wind power forecast error (and therefore the residual load forecast error) increases, causing a greater need for controllable reserves.

The distinction between operational and residual demand is relevant because the output of IGRs change the shape of the residual demand curve. Figure 3-1 illustrates this effect in South Australia. Operational demand is shown by the yellow line, and wind generation by the orange line. Residual demand (the difference between operational demand and wind generation) is shown by the green line, and represents the demand that must be met by conventional generators. Demand has a fairly predictable daily pattern during the winter months, with a morning and an evening peak (as well as a small peak around midnight due to off-peak hot water loads).[12] On most of the 16th and the 19th of July, wind generation was low, so that the shape of the residual demand curve was very similar to that of the demand curve. On July 17 and 18, there were two wind ramps where wind output exceeded 800 MW, so that residual demand fell steeply on both occasions. On July 18, wind production fell to below 200 MW, just as load was approaching its evening peak, resulting in a large and steeply rising residual demand curve.

[11] For loads, the degree of variability and uncertainty has increased in recent years with the increased penetration of small-scale solar PV installations deployed on household rooftops. The output of these installations is not separately metered, and is not 'visible' to the system operator. This aspect of solar PV technologies therefore introduces an additional element of uncertainty in predicting operational demand – the underlying variable demand profile overlaid with the variable output of rooftop PV installations.

[12] During the summer months, the shape of operational demand changes with a more gradual morning ramp, and a higher and more sustained afternoon plateau that peaks around 4-5PM, also with the same hot water peak.

Figure 3-1. Operational demand, wind generation and residual demand in South Australia, July 16 to 19 2016



Note: Operational demand is consumer demand, as 'seen' by AEMO; that is, aggregate consumption of electricity net of small-scale electricity generation, for instance from solar rooftop installations.

Source: AEMO data.

Overall, residual demand curves in systems with large amounts of wind tend to be 'peakier', with larger up and down movements, and multiple upward and downward excursions. The implication is that even when the output of IGRs has been forecast correctly, flexible conventional generation units which can change their output or come into service quickly (that is, ramp up or down) are needed to match (residual) demand. With more wind capacity, forecast errors will also increase in absolute terms, which also increases the need for reserves that can respond flexibly to unexpected increases in residual demand.

AEMO (2016) accordingly notes in its South Australian Renewables Report that due to the variability in wind and rooftop solar generation, larger residual demand changes are observed more often in South Australia. Between 2011–12 to 2015–16, the frequency of small changes (in the plus or minus 10 MW range) in residual demand has declined, but that of large changes in residual demand has increased. Large changes in residual demand must be met by flexible conventional generators, as well as through imports (interconnector limits permitting), and sudden large changes make managing the power system more challenging.

3.2 Operating reserves

Variability and uncertainty are not unique to wind generation. Demand cannot be predicted perfectly, and large power system equipment can fail. Operating reserves are therefore held to accommodate routine demand variability across short- and longer-term timescales, errors in predicting that demand, and unexpected events or ‘contingencies’, such as a generator tripping.

Random, minute-by-minute demand imbalances and contingencies must be addressed immediately, and happen too quickly for energy markets to respond. In liberalised power markets, these types of reserves are typically acquired by system operators in ‘ancillary services’ markets that operate in parallel to energy markets. Reserve-type ancillary services are provided by partly loaded or unloaded generation capacity that is on standby to be available to meet deviations in residual demand from predicted levels. The type of reserve that is offered by a conventional generator determines that generation’s operating profile. For instance, a generator that is contracted (‘enabled’) to instantaneously respond to a contingency, such as the sudden outage of a large generation unit, must be synchronised to the frequency of the grid, and must operate with sufficient headroom to be able to increase its output within seconds and maintain that output in response to a contingency. A generator that is enabled to counteract small downward changes in residual demand must operate sufficiently above its minimum stable generation point, so that it can flexibly reduce its output.

Operating reserves differ across many dimensions, including response speed and duration, frequency of use, direction of use, and type of control. There are many different classifications of operating reserves across different power systems, and differing rules apply to the types and quantities of reserves that are deployed. However, all power systems hold at least two types of reserve services that also exist in the NEM:

- ‘Regulation’ or ‘Regulating’ operating reserves are needed during ‘normal’ system conditions so that any imbalances between demand and supply is immediately resolved, and the system frequency stays within its nominal bounds. Regulation is provided by flexible generation resources connected to automatic generation control (AGC) systems, and addresses fast fluctuations in residual system load that require a fast generation response. Regulation is defined in an ‘up’ or ‘down’ direction to compensate for downwards and upwards variations in residual demand, respectively.

- ‘Contingency’ reserves are only used in the event of a sudden and unexpected event, such as a generation or transmission outage. Contingency reserve is provided by conventional generators (or responsive loads) that are online and synchronised, and can respond within very short timescales. As is the case in the NEM, there is typically a hierarchy of contingency reserves, with the fastest deployed first to arrest a sudden frequency excursion, followed by slower services that are then deployed to assist in moving the system frequency back to its nominal range.[13]

In the NEM, AEMO procures operating reserves in eight frequency control ancillary services (FCAS) markets. FCAS are generally supplied by conventional generators, but sometimes also by responsive loads (Table 3-1):[14]

- Regulation services encompass 'Regulation Raise' and 'Regulation Lower', depending on the direction of the response required. Regulation services are provided by synchronised conventional generators on AGC that adjust their operations in response to control signals from AEMO. The regulation requirement is determined dynamically in each 5-minute dispatch interval, and is adjusted as required, generally every 4 seconds, to match system variability, uncertainty and other factors (Riesz and McGill 2013).
- There are six types of contingency services, ranging from very fast (6 second) up or down services, to slower (60 second) up or down services, and to delayed (5 minute) up or down services. Contingency services are deployed sequentially to arrest a major frequency excursion, and are triggered by the frequency deviation that follows a contingency. In the NEM, as in other power systems, the amount of contingency reserve is based on the largest potential source of failure, such as a trip of the largest generator or load block, and is independent of the variability of load.

Table 3-1. NEM frequency control ancillary services

FCAS category	When used	Purpose	FCAS types
Regulation	Normal system conditions	Instantaneous & automatic correction of generation / demand imbalances in response to minor load or generation deviations	Regulation Raise Regulation Lower
Contingency	Following a contingency event	Correction of generation / demand imbalances following a major	Fast Raise (6 Second Raise) Fast Lower (6 Second Lower)

[13] Overseas, system operators in a number of markets additionally deploy fast-start contingency reserves. These reserves are usually capable of responding within a designated timeframe (15 to 30 minutes), and act to quickly restore load that has been shed by under-frequency tripping schemes following a contingency event.

[14] Regulation and contingency ancillary services are separate from other system services provided by conventional generators, but not IGRs. For instance, conventional generators automatically provide so-called 'primary' frequency control services via their 'governors' that automatically adjust output in response to very small and short-lived (<10 seconds) power imbalances.

FCAS category	When used	Purpose	FCAS types
		contingency event, such as the loss of a generating unit, major industrial load, or transmission element	Slow Raise (60 Second Raise) Slow Lower (60 Second Lower) Delayed Raise (5 Minute Raise) Delayed Lower (5 Minute Lower)

3.3 Impact of intermittent generation on operating reserves

When IGRs such as wind are introduced to a power system, the variability and unpredictability of these resources adds to the variability and unpredictability of load. The task of balancing residual demand and supply at all times and to supply sufficient operating reserves to compensate for forecasting errors is magnified and falls to conventional dispatchable generation. The impact that wind has on reserve requirements depends on several factors, including how wind generation affects the variability of residual demand, the ability of the system operator to predict residual demand, and the time horizon.

3.3.1 Regulation (seconds to minutes)

The additional reserve requirements and costs of balancing the system are initially driven by fluctuations in wind generation output. Wind output changes over short time frames such as seconds and minutes are managed using traditional regulation services. The need for regulation due to variability over this time frame is generally increased, but the extent to which this is the case depends on system-specific factors, including the characteristics of load and the geographic proximity of wind farms (Table 3-2).

In large power systems, frequency control services over time scales of seconds or minutes are not considered to be a crucial problem, but they can be a challenge for small systems and may become more of a challenge for systems with high penetration in the future (Holtinen 2011). It is, however, the case that even in the very short-term, the addition of wind makes the residual load less predictable, so that conventional generators with higher ramp rates or more flexibility need to be available to ensure stable system operation within the normal frequency bounds.

Table 3-2. Results of large wind integration studies – Additional regulation requirements

Power system	Date	Scenarios modelled	Impact on regulation reserves	Other comments
New York ISO	2005	3,300 MW of wind power relative to peak load of 33,000 MW	36 MW increase relative to existing requirement of 225 – 275 MW	N/a
Minnesota	2006	25% (15%, 20%) wind energy	12, 16, and 20MW increase for wind energy	Standard deviation of wind is 2 MW for

Power system	Date	Scenarios modelled	Impact on regulation reserves	Other comments
		5,700 MW wind relative to peak load of 21,000 MW	shares of 15% 20%, 25%	every 100 MW wind plant installed
Arizona	2007	1 – 10% wind energy	2.4 MW and 6.2 MW increase for wind energy shares of 4% and 10%	Standard deviation of wind is 1.5 MW for every 100 MW wind plant installed
California	2007	6,700 MW of wind	Regulation up: Up to 230 MW increase relative to existing 250 MW requirement Regulation down: 500 MW increase relative to existing 250 MW	N/a
ERCOT	2008	15,000 MW of wind, or 23% wind share of peak load	Regulation up: 53 MW increase relative to existing 232 MW requirement Regulation down: 48 MW increase relative to existing 233 MW	Standard deviation of wind is 65 MW
Southwest Power Pool	2010	10%, 20%, 40% wind energy	Regulation up and down requirements varied by season and wind penetration For 40 per cent penetration: - Additional 215 to 238 MW regulation up - Additional 234 to 256 MW regulation down	Standard deviation of wind is 1 MW for every 100 MW wind plant installed
New England	2010	Wind energy penetrations of 2.5%, 9%, 14%, 20% and 24%	Average regulation requirement increased by 79 MW from 82 MW for 9% penetration, by up to 231 MW for 20% penetration	N/a

Notes: The additional need for operating reserves is often determined on the basis of an analysis of the standard deviation of six-second changes in residual load to ensure that upwards of 99 per cent of all changes can be met.

Source: Ela et al. 2011. Milligan et al. 2015.

In the NEM, AEMO (2016c) has similarly determined that the increasing variability and uncertainty associated with intermittent renewables will affect regulation requirements. For the NEM overall, regulation FCAS will increase by about 2020, but in regions that are at greater risk of 'islanding' (separating from the remainder of the NEM), regulation FCAS requirements may change sooner. AEMO notes that in South Australia, wind generation is an increasing source of variability, and that any growth in wind generation in that region will increase the amount of regulation that is required. The projected rapid large-scale PV growth in South Australia will also increase the regulation requirement. According to AEMO, and given that sufficient units in South Australia that are able to provide regulation services must be online and operate at a suitable point in their output range, system security considerations will increasingly affect dispatch outcomes when islanding is a credible risk. The implication is that generators whose capacity is reserved for providing regulation services will not be dispatched to their full capability, increasing costs for consumers.[15]

3.3.2 Redispatch and load following (minutes to hours)

Over timeframes of many minutes and hours, the changes in output from multiple wind farms are much less random and larger. The variability of wind production patterns changes the commitment and dispatch of conventional generators and transmission loadings relative to a situation without wind, and make the residual demand less predictable, as also illustrated in Figure 3-1. As any point forecast of wind generation is subject to error that is independent of demand, this will reduce the reliability of the residual demand forecast. Further, as wind generation capacity increases, the error will increase in absolute terms and as a proportion of demand. These greater forecast errors need to be accounted for to maintain the secure operation of the system, and need to be handled by conventional generators, or possibly at some future point, by higher capital cost storage systems.

All recent wind integration studies therefore identify the need for more flexible conventional generation capacity to respond to variability in residual demand and forecasting errors (Ela et al. 2011, Milligan 2015). These additional reserve requirements are not fixed over time but depend on the specific output level of wind turbines at a point in time. For instance, wind generation forecast errors are a function of average wind production, which exhibits the most variations (in terms of up and down changes in output) when a wind turbine operates in the middle range (40 to 60 per cent) of capacity due to the wind turbines being on the steepest parts of their wind speed to wind power conversion curves.

Over timeframes of less than an hour, US power markets that are dispatched and settled over a longer timeframe than the NEM use so-called 'load following' reserve services to correct power imbalances. Given the greater uncertainty over that

[15] Generators that are constrained from operating in the energy market and whose energy market revenues are therefore reduced, may furthermore seek to maintain equivalent revenues through the provision of ancillary services, which may in turn increase ancillary services prices.

timeframe, all the studies summarised in Table 3-2 identify increased greater requirements for these services as the penetration of wind increases.

In contrast, the NEM is a 'fast' market where dispatch is optimised across five-minute dispatch intervals, and power imbalances lasting longer than 5 minutes are partially resolved in the spot market, aided by the ongoing dispatch of 5-minute delayed contingency reserve services. In theory, when circumstances change, NEM generators are redispatched at the commencement of the next dispatch interval, rather than relying on regulation reserves, 'load-following' or other balancing mechanisms. However, system frequency correction relies on AEMO correctly forecasting residual demand, in particular the intermittent generation component. In practice, therefore, existing reserves may be needed to compensate for cumulative forecasting errors in subsequent dispatch intervals. With increasing forecasting errors, conventional generators then need to have sufficient capacity and flexibility to respond to varying dispatch instructions as forecast errors inevitably occur.

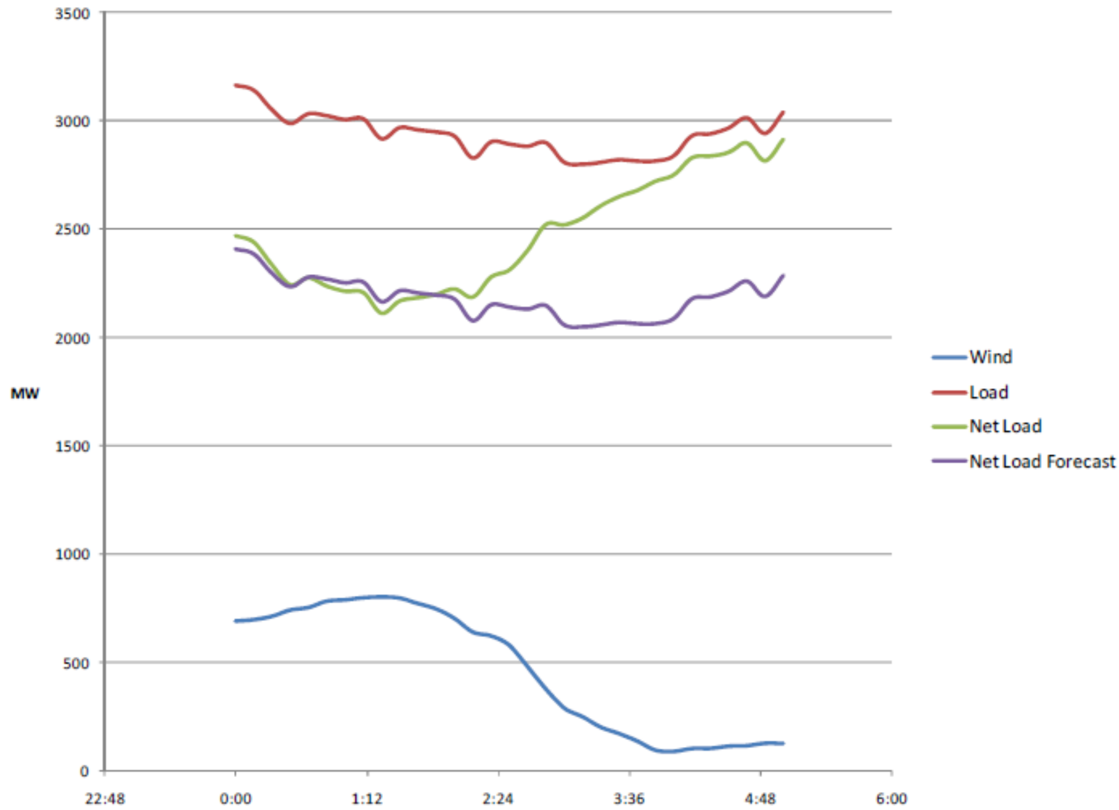
3.4 Ramp reserves (1 to 6 hours)

The implications of the additional variability and uncertainty introduced by intermittent resources for operating reserves have been extensively studied in overseas markets. There is general agreement that the total amount of operating reserves held will need to increase, and that no additional contingency reserves will be needed, since a total loss of wind power in the timeframe of a contingency is not a realistic scenario. All the system studies referenced in this report also identify a need for more flexible conventional generation that is better positioned to change its output in response to variations in the output of renewables. A number of system operators have additionally determined the impact of wind on system security to be sufficiently material to warrant introducing additional reserve requirements to guard against the effects of large wind ramp events.

3.4.1 An illustration

Regulation and contingency reserves deal with load and generation variability, and with large generation and transmission failures. However, these types of reserves are not suitable for dealing with large wind ramp events (GE Energy 2008, Holttinen 2011). The central concern here is with situations where wind generation has been over-forecast, and therefore residual demand under-forecast, so that not enough conventional generation is online or available on stand-by to meet demand. In Figure 3-2, for instance, wind generation output (the blue line) falls from about 1AM to about 3.30AM. That drop in wind output was not forecast, so that there is a divergence in the residual (net) load forecast (the purple line) and actual residual (net) load (the green line). Given the residual demand forecast, only about 2,100 MW of conventional generation may be online (plus additional contingency reserves). Closer to real-time, it emerges that residual demand is (unexpectedly) 600 MW higher than forecast, and that additional conventional generation needs to be made available to generate. If contingency reserves were used to compensate for the drop in wind, there would not be sufficient reserves to respond to a conventional contingency event, and the system would have to shed load if such a contingency occurred. At the same time, the system would not need to respond to the actual 600 MW increase in net load within a very short time, since the actual (wind down ramp) event took over 2 hours to play out. Slower conventional resources, including resources that may be offline can instead be deployed to manage this forecast error, provided they remain available to do so.

Figure 3-2. Residual load forecast that does not forecast a wind ramp



Source: Ela et al. 2011.

3.4.2 Implications for operating reserves

While wind ramp events can be very large, and their duration and magnitude are difficult to forecast, they tend to occur over multiple hours.[16] Wind ramp events generally do not therefore require fast acting contingency-type reserves to be deployed. The 'ramp reserve' services that have been introduced in a number of markets are then not used to address instantaneous failures, but events that occur over timeframes of up to a number of hours. These services are provided by conventional generators (or responsive load) that can be activated and dispatched

[16] The exception to this may be during unusual weather events when instantaneous and large fluctuations in wind output have occurred in the NEM.

over longer timeframes, and that are sufficiently flexible to compensate for large wind output cycles. The risks to system security from large, rapid decreases in wind generation output are also not uniformly distributed over time or uniform in size. The size of ramp reserves is not fixed, in the sense that the amount of reserves needed depends on the magnitude of the potential change in wind output, and on the likely forecast error. Furthermore, when system operators are more confident of actual operating conditions closer to real-time, the need to hold reserves is reduced.

An important motivation for introducing a ramp or stand-by reserve requirement is that unforecast wind ramp events or low wind conditions can lead to price spikes that are created by a temporary shortage of flexible generation capacity, rather than by a general capacity shortage (Ela et al. 2012). It could be argued that similar outcomes have also been observed in South Australia where steep demand changes are requiring quicker generation response times than can sometimes be accommodated, resulting in very high price spikes. Table 3-3 provides an overview of the key contributing factors to very high energy prices in South Australia in the second half of 2016, as reported by AEMO in its ‘pricing event reports’. In all but one instance, wind generation was either very low or fell during the relevant dispatch intervals, sometimes dramatically. Furthermore, lower priced conventional generation was available, but could not be deployed and set a (lower) spot price because of operational inflexibilities, for instance because the relevant generators were not available, available but not synchronised, or due to ramp rate limitations. AEMO’s ‘pricing event’ reports point to forecasting errors in a number of instances, including errors in forecasting hot water loads, but also wind forecast errors on 1 November, 12 July, and 22 July 2016.

The Australian Energy Regulator’s assessment of the causes of high energy prices on July 13 2016 also identified wind forecast errors as the major contributing factor (AER 2016). While wind generation for the 6.30 AM trading interval was forecast to be between 900 MW and 820 MW, actual wind output was only around 600 MW. Given the forecast, relatively little conventional generation capacity was offered in the lower price bands. As that lower priced generation was fully dispatched or restricted by ramp rate limitations, high priced generation had to be dispatched to meet demand with prices reaching $14,000/MWh from 6.20 am to 6.30 am.

Table 3-3. South Australian high energy price events – July through November 2016

Price event	Date, time	Wind generation output	Load	Network	Conventional generation
\$508.89/MWh to \$8,897.80/MWh	06 July to 08 July, for 41 TIs	During all high priced 5-minute DIs, wind generation was between 0 MW and 366 MW, with an average of 51 MW.	N/a	Planned network outage limiting SA imports over the Heywood interconnector	Torrens Island B unit 3 and Pelican Point CCGT were unavailable 6 to 8 July. Torrens Island A units 1, 3 and 4 were unavailable for periods 6 and 7 July. Lower priced generation was available but limited due to: - ramp rate limitations (Torrens Island A units 3 and 4, Hallet PS, Dry Creek GT unit 3, Snuggery PS, Osborne PS, Mintaro GT) - fast start profiles (Snuggery PS, Dry Creek GT units 1, 2 and 3, Lonsdale PS, Angaston PS, Port Lincoln GT units 1 and 3, Port Stanvac PS 1, Hallet PS, Ladbroke Grove PS units 1 and 2, Quarantine PS unit 5) - requiring more than 1 DI to synchronise (Hallet PS, Snuggery PS, Dry Creek PS units 1, 2 and 3, Lonsdale PS, Port Lincoln GT units 1 and 3) - constrained off due to network limitations
\$2,324.03/MWh	11 July (TI ending 0000 on 12 July)	N/a	Increase in demand by 221 MW due to hot water load management	Planned network outage limiting SA imports over the Heywood interconnector	Lower priced generation was available but limited due to: - ramp rate limitations (Torrens Island PS B Units 3) - requiring more than one DI to synchronise (Hallett PS, Dry Creek CGT unit 3)

Price event	Date, time	Wind generation output	Load	Network	Conventional generation
					- constrained off due to network limitations
$534.26/MWh to $4,905.67/MWh	14 July over 13 TIs between TIs ending 0900 hrs and 2100 hrs	During all high priced DIs, SA wind generation was low, between 134 MW and 367 MW	N/a	Planned network outage limiting SA imports over the Heywood interconnector	Planned generation outages at Torrens Island B unit 4, Pelican Point CCGT. Lower priced generation was available but limited due to: - requiring more than one DI to synchronise (Quarantine PS unit 4) - ramp rate limitations (Port Lincoln GT unit 3) - fast start profiles (Angaston PS 1, Port Stanvac PS 1) - constrained off due to network limitations
$1,659.54/MWh	19 July, TI ending 0700 hrs	SA wind generation decreased by 31 MW to 244 MW	SA demand increased by 97 MW	Planned network outage limiting SA imports over the Heywood interconnector	Planned generation outages at Torrens Island A unit 1, and B unit 4. Lower priced generation was available but required more than one DI to synchronise (Hallet GT and Quarantine PS unit 5).
$2,484.65/MWh, $2,337.47/MWh	22 July, TIs ending 1630, 1700 hrs	SA wind generation decreased by 309 MW, from 918 MW for DI ending 1600 hrs, to 609 MW for DI ending 1635 hrs, due to high wind speed cut-out of turbines at some wind farms.	N/a	Limited interconnector support, Planned network outages	Planned generation outages at Torrens Island A units 1, 3 and 4, Torrens Island B unit 3, Pelican Point CCGT. Lower priced generation was available but limited due to: - requiring more than one DI to synchronise (Hallet GT, Quarantine GT unit 5, Mintaro GT) - constrained off due to network limitations

Price event	Date, time	Wind generation output	Load	Network	Conventional generation
$4,772.49/MWh	1 August, TI ending 0930 hrs	Reduction in SA wind generation to 339 MW and 325 MW, respectively	High morning peak demand of 1,738 MW at DI ending 0900 hrs	Planned network outage	Lower priced generation was available but limited due to: - ramp rate limitations (Hallet PS, Torrens Island B unit 3, Dry Creek GT units 2 and 3, Snuggery PS) - requiring more than one DI to synchronise (Snuggery PS, Dry Creek GT unit 3, Quarantine PS unit 5)
$2,361.27/MWh	4 Sep, TI ending 0000	126MW	1,646 MW, spike in hot water load	Interconnector flow limitations	Cheaper generation was available but limited due to fast start inflexibility profiles
$1,783.47/MWh	8 Sep, TI ending 2100	Decrease in SA wind generation between 2030 hrs and 2035 hrs by 75 MW to 697 MW	N/a	Planned network outage, limited interconnector support	Cheaper priced generation was available but required more than one DI to synchronise (Ladbroke Grove GT units 1 and 2).
$4,708.99/MWh	25 Oct, TI ending 0000	Low SA wind generation at 216 MW and 206 MW for DIs ending 2335 hrs and 2340 hrs, respectively	1,466 MW, spike in hot water load	Interconnector flow limitation	Cheaper priced generation was available but either required more than one DI to synchronise (Snuggery and Dry Creek GT 3), or was limited by its ramp rates (Hallet GT)
$2,298.56/MWh	1 Nov, TI ending 0730	Between DIs ending 0715 hrs and 0720 hrs, SA wind generation decreased by 40 MW to 264 MW	SA demand increased by 14MW to 1,507 between DIs ending 0715 hrs and 0720 hrs, reaching morning peak demand.	Interconnector flow limitation	Cheaper generation was available, but required more than one DI to synchronise (Dry Creek GT unit 3).

Notes: 'TI' refers to trading interval. 'DI' refers to dispatch interval.

Source: AEMO Pricing event reports.

3.4.3 Ramp reserves in ERCOT

The Texas ERCOT market design is similar to that of the NEM in that ERCOT is also an energy-only market where offers are cleared across 5-minute dispatch intervals. ERCOT has very limited interconnections with other electrical regions in North America, and has the highest installed wind capacity in the United States.[17]

ERCOT has modified its existing ancillary services to accommodate the greater reserve requirements associated with increasing shares of intermittent resources (Woodfin 2014, 2016).[18] Regulation services that are used to correct small imbalances (as in the NEM) are adjusted annually to account for wind capacity additions. ERCOT has additionally changed how it procures contingency services to incorporate both contingencies, as well as uncontrollable wind output decreases combined with load increases:

- 'Responsive Reserve Service' (RRS) – spinning reserves – were historically only used to restore frequency within the first few minutes of a contingency event, with the quantity of RRS set to cope with the trip of the two largest generators. Rather than procuring a constant amount of RRS, ERCOT now procures larger and varying quantities of RRS that additionally depend on expected diurnal load and wind patterns.
- ERCOT has also historically procured a Non-Spinning Reserve Service (NSRS) to 'replace' RRS following a contingency event.[19] NSRS is a supplemental reserve service provided by off-line generators that are capable of ramping to a specific output level in 30 minutes or less (or load resources capable of being interrupted within 30 minutes for at least one hour). When dispatched, NSRS services, inclusive of start-up costs are paid for by the market. Today, NSRS is also used on a stand-alone basis to compensate for wind and residual load forecast errors over periods lasting longer than 30 minutes. NSRS is procured such that the combination of non-spinning reserves and regulation up service will cover at least 95 per cent of the calculated net load forecast error, and the size of the largest generation unit.

[17] The ramp reserve products introduced in other US power markets are briefly described in Appendix B.

[18] In 2013, ERCOT proposed a suite of revised and new ancillary services to manage the future operational impacts of greater shares of intermittent and non-synchronous generation. These proposals were not approved.

[19] If fast-acting generators are deployed for 'too' long following a contingency event, they are not available to respond to a subsequent contingency. Given that standard power system operations require a system to always be in a position to accommodate a contingency, that fast-acting generation must then be 'replaced' by slower acting reserves, so as to stand ready for the next contingency.

The approach adopted in ERCOT to managing wind ramp events is relevant to the NEM, because the ERCOT market incorporates many of the same design elements, and the ERCOT system has similarly historically been dominated by relatively inflexible thermal generation capacity. Unlike the situation in South Australia, ERCOT cannot draw on interconnector capacity to assist in managing large residual load changes. However, the recent experience in South Australia seems to suggest that at least in circumstances where there are transmission constraints, high energy prices outcomes occur, and that these high price outcomes occur in circumstances where lower priced generation was not prepared to respond sufficiently flexibly, including because of forecasting errors.

3.5 Conclusions

The wind studies that have been undertaken in US power markets indicate that reserve requirements increase over all operational timescales as the share of intermittent generation increases. In addition, flexible conventional generation capacity is needed to accommodate the rapid changes in residual load that are associated with greater shares of intermittent renewable generation.

Conventional regulation services can generally continue to be used to manage residual load variability at very short timescales. However, when the share of intermittent generation in a power system increases, regulation requirements are also increased, sometimes significantly so.

In power systems with higher levels of wind penetration, large wind ramp events become an issue, particularly when they are combined with increases in demand. In these circumstances, system operators have to manage steeply rising residual demand curves. These types of events are difficult to forecast reliably, so that flexible conventional generation capacity may not be available to balance demand or avoid temporary price spikes. There are some indications that wind ramps and associated residual load forecasting errors are already an issue in the South Australian region of the NEM. System operators in other liberalised power markets have correspondingly identified a need for 'ramp reserves' to mitigate against the system security and price implications of large wind ramps. In ERCOT, for example, which has a similar market design as the NEM, slower 30-minute reserves can now be called on to be available to address wind ramp events.

4 Implications for the NEM

This section discusses the implications of the integration costs that intermittent generation resources impose on the residual power system for the NEM:

- Section 4.1 comments on the overall welfare objective of power systems;
- Section 4.2 considers the incentives for developers of renewable power stations to minimise integration costs; and
- Section 4.3 discusses various options to ensure that these incentives are better aligned with the NEM objective.

4.1 Welfare implications of integration costs

Irrespective of how electrical power systems are organised – in the form of a liberalised market such as the NEM, or as a centrally controlled sector – such systems are designed to meet aggregate consumer demand to a given standard of reliability and at least cost. An economic welfare analysis of a power system then focuses on minimising total system costs, which comprise all costs associated with meeting demand reliably and maintaining a secure power system, including investment costs and the discounted life-cycle variable cost of all plants, grid infrastructure and storage systems (Ueckerdt et al. 2013). The need to minimise system costs over a longer-term timeframe that also incorporates investment, in the interests of consumers, is similarly enshrined in the National Electricity Objective, as stated in the National Electricity Law.[20]

The objective of promoting the efficient, reliable and secure operation of the NEM, including by promoting efficient investment, implies that the costs of integrating IGRs should be incorporated within the NEM governance framework. IGR integration costs are the additional investment and operational cost that these technologies cause to be incurred in the non-intermittent part of the power system, and are therefore akin to negative economic externalities. Integration costs differ across power systems, but in systems dominated by less flexible thermal generation resources, as is the case in the NEM, these costs can be substantial (Hirth et al. 2016). For generation from wind, for instance, and even allowing for long-term adaptation in the generation mix to

[20] The National Electricity Objective (National Electricity (NSW) Law, Sect 7) states that:

The objective of this Law 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.

account for the variability and uncertainty of intermittent renewables, these additional integration costs are estimated to be in the range of AU$ 37.50 to AU$ 52.5 per MWh when wind penetration reaches 30 to 40 per cent.

The NEM Rules have been amended over the years to accommodate IGRs, including by introducing new market participant categories and by modifying the NEM planning and dispatch processes to accommodate intermittent generation. There is now a greater awareness of the system security challenges associated with rising shares of intermittent generation.[21] However, there is no consistent framework that incorporates the costs caused by intermittent renewables in the non-intermittent power system, and that ensures that these costs are minimised by aligning intermittent generators' incentives accordingly.

From a broader welfare perspective, the existence and size of integration costs should be incorporated in any analysis of the costs and trade-offs associated with differing policy choices. For instance, the magnitude of IGR integration costs means that the system costs of achieving the various state-based renewable energy targets are (far) greater than the cost of the renewable capacity itself. Furthermore, and as is the case with any other economic externality, the objective of minimising total system costs requires appropriate pricing signals such that IGRs internalise the additional costs they impose on the remainder of the power system. Specifically in the context of the additional reserves needed to accommodate larger shares of intermittent generation, achieving the longer-term NEM efficiency objective implies that the corresponding costs be identified and allocated to IGRs on the basis of causality. In the absence of some form of cost attribution mechanism along these lines, there can be no expectation that investors in IGRs will adopt the technologies (or apply other measures) so as to minimise or at least limit the increase in overall system costs. As a result the total system costs of meeting electricity demand will increase, potentially significantly so, and will be borne by electricity consumers.

4.2 NEM investment incentives

In the NEM, market generators whose output is intermittent and with an aggregate nameplate capacity of at least 30MW are classed as 'semi-scheduled'. Semi-scheduled generators do not participate in the dispatch process and are not required to comply with dispatch instructions to the same extent as conventional generators. While AEMO can in theory limit a semi-scheduled generator's output in some circumstances

[21] The AEMC has initiated the 'System Security Market Frameworks Review', which will recommend changes to the regulatory framework to meet the power system security challenges in the NEM caused by increasing levels of intermittent generation. The AEMC will draw on the work being undertaken by AEMO as part of its Future Power System Security Program, and will consider five related rule change requests relating to an inertia ancillary services market, managing the rate of change of power system frequency, modifying emergency under-frequency control schemes, managing emergency over-frequency control schemes, and managing power system fault levels.

to manage flows over network elements, in general, these generators can generate up to the maximum of their registered capacity at all other times, displacing more reliable forms of generation. 'Non-scheduled' intermittent generators with a capacity of less than 30MW are not subject to any output limits, regardless of network conditions.[22]

Generation from wind is the cheapest form of renewable generation, and new large-scale renewable generation capacity in the NEM has overwhelmingly taken the form of wind generation. As of February 2017, the AEMO website reported installed wind generation capacity of 3,830 MW and 232 MW of solar generation capacity. Looking forward, the National Transmission Network Development Plan (NTNDP) projects that around 9,700 MW of large-scale wind and solar capacity will be commissioned by 2020-21, and almost 17,000 MW by 2029-30.[23] Alternatively, the AEMO website lists 12,442 MW of proposed wind capacity, and 1,724 of proposed solar capacity.

As described in this report, the variability and uncertainty of intermittent generation, particularly from wind, require more flexible operating patterns from conventional generators, and increases the amount of reserves that must be held by the system, including to cope with situations where the output from intermittent generators is low or zero. Renewable technologies that offer significant improvements in dispatchability and that reduce costs in the non-intermittent system such as concentrating solar power (CSP) with thermal storage, or intermittent generation developments combined with integrated storage solutions more generally have not been deployed in Australia to date. The observation that investment in renewables in the NEM consists entirely of intermittent technologies that impose the largest integration costs on the power system is a reflection of the NEM Rules, which only attributes a fraction of these costs to intermittent generators.

4.2.1 Regulation

Semi-scheduled generators currently make a contribution toward the costs of regulation reserves according to the so-called 'causer pays' methodology (AEMO 2013). However, the extent to which this methodology is aligned with the causes or drivers of regulation requirements is questionable. Under the causer pays methodology, the costs of regulation are allocated to participants on the basis of 'contribution factors'. For semi-scheduled generators, the contribution factors are based on deviations from a 'reference trajectory', which is a straight-line interpolation between actual dispatch levels in successive (5-minute) dispatch intervals.[24] This

[22] In aggregate, around 3,000 MW of non-scheduled generation capacity is installed in the NEM.

[23] In addition, rooftop PV capacity is projected to increase to around 7,700 MW by 2020-21, and to almost 16,000 MW by 2029-30 from currently 4,900 MW.

[24] For conventional, dispatchable generators, the reference trajectory is a straight-line interpolation between each generator's dispatch target in successive (5 minute) dispatch intervals.

methodology is intended to incentivise intermittent generators to minimise output variations between dispatch intervals. However, from a system perspective, what causes the costs of regulation services to be incurred are the variability of residual demand and/or residual demand forecasting errors, as measured by the respective standard deviations (Holttinen et al. 2008). From a perspective of establishing causality, what matters therefore is not the stand-alone variability of, say, wind generation, but the extent to which that variability contributes to and is correlated with the variability of residual demand or with residual demand forecasting errors.

4.2.2 Longer-term reserves

Over a longer timeframe, the utilisation or back-up costs of maintaining significant amounts of (underutilised) dispatchable capacity to compensate for the wide swings in output of intermittent generators will increasingly be incurred in the NEM. The NEM is an energy-only market, and does not incorporate any form of capacity payment whereby generators are paid for standby or reserve capacity according to their contribution to system reliability. Significant amounts of conventional capacity have already been withdrawn from the market, and the additional withdrawal of at least 3,800 MW of coal and gas plants has been announced. These developments will affect the reliability of electricity services, as is reflected in AEMO's system security assessment. AEMO's updated 2016 Electricity Statement of Opportunities projects breaches in the reliability standard in South Australia and Victoria by 2017–18 following the closure of Hazelwood power station (AEMO 2016b). The question of how that capacity will materialise and who will bear the costs has not been addressed to date.

4.3 Aligning IGR incentives to minimise the costs of operating reserves

The variability and uncertainty of IGRs increases the response requirements from conventional generators and responsive loads. Over very short operational timeframes, regulation requirements are increased. Over longer timeframes, sufficient flexible generation capacity needs to be available to cover ramp events whereby the combined output of intermittent generators falls over many hours, and situations where little or no intermittent capacity produces energy, sometimes for sustained periods.

The following sections comment on various high-level options to better align the incentives of investors in intermittent generation projects with the objective of minimising the long-term system costs of the NEM, in the interests of consumers. Allocating costs to market participants on the basis of cost-causation provide transparent signals to participants that, if well defined, provide incentives for efficient investment and behaviour (Milligan et al. 2013). In the present context where the focus is on the reserves that are needed for the secure operation of the system, the question is then how to align the incentives of investors in intermittent generation projects with the objective of minimising system costs.

4.3.1 Regulation cost attribution

Reserves are generally determined on the basis of probability calculations, such that all variability within a given probability range is covered, for instance 99.99 per cent of the variability of residual load, or, relatedly, based on a probability of exceedance (POE) calculation (Holttinen et al. 2008, Kirby and Hirst 2000).[25] Alternatively or additionally, the regulation requirement may be determined by the probability range around residual load forecast errors. The total amount of regulation service required is not additive, but depends on how correlated the individual components of residual demand (i.e. operational demand and intermittent power generation) are. If the component fluctuations are completely correlated, the regulation requirement will be higher than if fluctuations are uncorrelated, which will in turn be higher than if fluctuations are negatively correlated.

From a perspective of identifying causality, the increase in the regulation requirement that should be attributed to wind (or other intermittent generation) is therefore the extent to which wind generation adds to (or is correlated with) system (residual load) variability or system forecast errors.[26] That variability can be allocated on the basis of causation while accounting for the non-linearity introduced by correlation effects, and in a manner such that the total allocated variability always equals the total system variability (Kirby and Hirst 2000, King et al. 2012). The corresponding 'vector allocation' method is a straightforward geometric approach to determining the contribution of specific components of residual load to total system variability, accounting for correlation.

4.3.2 Reserve and ramp requirements

Over timeframes to 2020 and beyond, the challenge in the NEM will increasingly be to ensure that sufficient conventional generation capacity (or other suitable technologies) will be available to ensure reliable electricity supplies in circumstances when wind and solar generation are low, and moreover that the conventional generation is sufficiently flexible to cope with changes in aggregate IGR output. Different mechanisms can be considered to achieve such an outcome.

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[25] If residual load variations within a regulation timeframe are normally distributed, the standard deviation σ indicates that about 68 per cent of all (residual load) variations will lie within the range of the mean by +/- σ, where the mean is 0, given that Regulation is intended to address random variations in residual load around the dispatch point. Taking a range of +/- 3σ means that 99 per cent of events will be covered, and +/- 4 σ means that 99.9 per cent of variability will be covered. Alternatively, if the chosen POE level is 99 per cent, then the entry for the 99th percentile can be extracted, which corresponds to 3σ in a normal distribution.

[26] For instance, AEMO publishes a Short Term Projected Assessment of System Adequacy (ST PASA) supply and demand forecast covering six trading days from end of the trading day covered by most recent pre-dispatch schedule with a half hourly resolution. The ST PASA incorporates 10% POE and 50% POE demand forecasts, as well as unconstrained intermittent generation forecasts for each semi-scheduled unit, and could be used as a reference for quantifying forecasting errors once real-time outcomes have been observed.

Minimum performance standards

Given that integration costs are a consequence of the variability and unpredictability of output of intermittent generators, the most obvious remedy would be to put in place certain minimum performance standards that such generators must meet. For instance, intermittent generators could be required, as a condition of connection, to ensure that at least, say, 20 per cent of registered capacity would be 'firm'; that is, guaranteed to be physically available. If such a requirement existed, wind and solar generators would need to invest in storage or alternative generation technologies to enable them to provide a minimum level of output.

In effect, such a requirement would require each intermittent generator to provide at least some share of the back-up capacity required by the system when that generator's output is low or zero. However, generation plants are characterised by economies of scale, so that the cost of one large generator is less than that of multiple small generators of the same aggregate capacity. Additionally, reserve services tend to be characterised by economies of scale and scope, so that it is generally cheaper to procure reserves for the system as a whole, rather than for each individual consumer or generator. While a requirement for a minimum level of firm capacity may then deliver at least a minimum level of reliable output from intermittent plants, this option is unlikely to minimise system costs overall.

Network solutions

The 2016 NTNDP focuses on the implications of current policy settings that incorporate Australia's COP21 commitment, the RET and the Victorian 50% Renewable Energy Target (VRET), but not the Qld 100% Renewable Energy Target. The assessment highlights that the Eastern Seaboard power systems will be severely challenged, including because system strength is expected to materially decline across the NEM, in particular in those areas where large quantities of intermittent renewable capacity would be located, and because the withdrawal of conventional generators will make the system less resilient. The NTNDP also identifies numerous network elements across all regions of the NEM where the installation of additional remotely located renewable generation will result in transmission limitations.

Consistent with its stated purpose, the focus of the NTNDP is on network solutions to address system security concerns, including:

- augmenting existing and commissioning new inter-regional interconnectors to enable generation capacity and reserves to be shared (Table 4-1);
- investing in regional transmission networks for the purpose of connecting new remotely located intermittent generation, where the costs of upgrades to

accommodate the VRET alone is initially projected to amount to more than $2.1 billion;[27] as well as

- numerous possible investments to improve system strength (such as by installing new conventional generators, synchronous condensers, static synchronous compensators or other voltage control equipment), or to assist in maintaining frequency stability (such as by commissioning or augmenting interconnectors, or installing new conventional generators, special protection schemes, high inertia synchronous condensers, or retrofitting retiring conventional generators).

Table 4-1. NTNDP interconnector augmentation/investment options

Description	Increase from present limit Forward / reverse direction (MW)	NPV of annualised costs to 2035-36 ($ millions)
Augmented NSW to Queensland interconnector	450 / 300	$136
Victoria to NSW interconnector	170 / 0	$74
New SA to Victoria interconnector	325 to 650 both directions	$500 to $750
New SA to NSW interconnector	325 to 650 both directions	$500 to $1,000
New Bass Strait interconnector	600 / 600	$940

Source: AEMO 2016d.

The costs of the interconnector and transmission augmentation options and other network-related investments described in the NTNDP give an indication of the costs of integrating intermittent generation technologies in the NEM. These investment options have been prepared on the basis of, and take as a given, the most recent forecasts of future intermittent capacity. Under the current NEM regulatory framework, the costs of augmenting the 'shared' transmission network (that is, those network assets that are not customer or generation connection assets) are attributed to consumers. As such, the NTNDP implicitly assumes that the tremendous network costs of integrating IGRs will be borne by consumers. None of the costs would be attributed to IGRs, so that IGRs would have no incentive to install technologies to reduce the need for reserves or otherwise assist in maintaining the strength and security of the power system. It seems doubtful that such an outcome could be

[27] These costs relate to removing transmission limitations on the Ballarat – Waubra – Ararat – Horsham 220 kV lines, the Redcliffs – Weman – Kerang 220 kV lines, the Ballarat – Terang – Moorabool 220 kV lines, and to deliver the output of wind farms at Kerang, Horsham and Ballarat to load centres.

characterised as efficient in terms of minimising the long-term investment and operational costs of the power system.

Generation capacity payments

Cramton et al. (2013) have argued that generation capacity payments are an important wholesale market design option as the share of IGRs increases. Neither wind nor solar energy can provide firm energy, and cannot therefore generally substitute for conventional generation resources. At the same time, at higher penetrations, IGRs increase price volatility and tend to depress market price levels, as well as reducing the utilisation of conventional capacity. Existing conventional generation capacity then withdraws from the market, as is also the case in the NEM, and investment in conventional generation that is needed to maintain a secure power system is disincentivised. Some form of capacity payment to conventional generators may then be needed to ensure that sufficient firm generation capacity is available to meet demand reliably and securely.

Different types of capacity mechanisms exist in many jurisdictions to ensure that sufficient firm energy is available at all times to meet demand, and to ensure long-term generation adequacy. Centrally administered capacity payments are applied in many European electricity markets, whereby generation units are paid according to their contribution to the overall system security or reliability (Batlle and Rodilla 2010). There are differing approaches to how the (firmness or reliability) product is defined (for instance, based on the expected availability of generating units), and how capacity payments are calculated. Electricity markets that incorporate capacity payment are common in the United States and also define a capacity product, but rely on one or more capacity markets to determine capacity prices. In these markets, capacity payments are referenced to a reliability criterion such as a reserve margin, and impose an obligation on retailers (referred to as 'load serving entities') to pay for their proportionate share of generation capacity (or demand response).

In practice, designing well-functioning capacity payment systems or capacity markets is complex. Administratively determined capacity payments have been criticised for failing to provide the right incentives to ensure that generators are operating, or for failing to ensure that generators are adequately compensated. The original designs of US capacity markets have been modified over the years, but concerns remain about the volatility of capacity prices and the corresponding problems in underwriting long-term generation investment on that basis.

Nonetheless, within a capacity payment framework, intermittent generators would earn low capacity credits which would decline at greater penetrations of IGRs. Capacity markets or capacity payments would therefore, in a limited sense, reduce the incentive to deploy IGRs without regard to system costs. It is also the case that energy prices are generally lower in capacity markets than in energy-only markets. The NEM as an energy-only market relies on a very high and ever increasing Market Price Cap (MCP) to ensure that sufficient generation is available to meet the NEM reliability standard for unserved energy. As the share of IGRs increase, the MCP may need to increase further to incentivise adequate reliable generation supply. A high and increasing MCP raises the risks of participating in the NEM for all market participants, including customers.

Overall, the implementation of some form of capacity payment arrangement in the NEM would need to be considered as a longer-term option for ensuring that sufficient reliable generation capacity is incentivised. At the same time, capacity payments would represent a major market design change for the NEM, and would entail numerous related modifications to the energy market and market participants' and AEMO's systems, with correspondingly high implementation costs.

Ramp reserve product in the NEM

The option that is proposed here is an incremental one that may assist in at least limiting some of the costly transmission investments described in the NTNDP, and that would not require extensive NEM market design changes: to expand the range of ancillary services products currently administered by AEMO to incorporate a ramp reserve service similar to the service that has been implemented in ERCOT.

As reviewed in this report, the experience with IGRs in overseas power markets and in South Australia shows that power systems with large shares of intermittent resources require additional operating reserves that need to be provided by sufficiently flexible conventional generators. The NEM does not currently specifically compensate generators for this type of flexibility, nor does it attribute the costs of this flexibility to IGRs whose operational patterns require it to be made available, for instance to respond to large wind ramp events.

As is the NEM, ERCOT is an energy-only market that has historically relied on energy price signals to coordinate generator commitment and dispatch decisions. Energy-only markets fundamentally rely on spot market prices to pay for the conventional generation capacity that is required to operate the system securely, yet (as in the NEM) the increasing deployment of subsidised renewables has distorted these price signals. Given high wind penetration in Texas, and the associated challenges to maintaining system security, ERCOT has then modified its existing contingency reserve requirements to enable flexible generation resources to be called on to manage large residual load changes associated with large wind ramp events. ERCOT now draws on non-spinning reserves as a ramp reserve service that is called on by the system operator in situations where there is a material risk of a wind ramp or low wind event, as measured by the residual load uncertainty or forecast error.

There are a number of advantages to modifying the existing suite of FCAS services within the NEM to incorporate an additional ramp reserve ancillary service that would be dynamically determined based on system conditions:

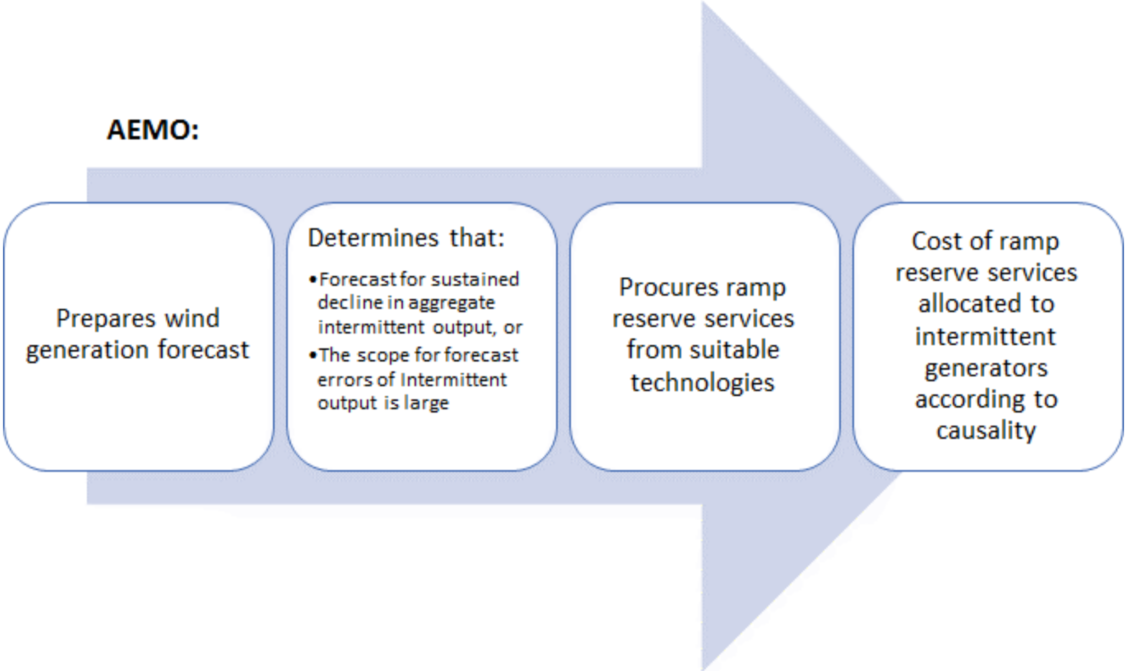
- The availability of ramp reserves would assist in managing both the system security and the price spike implications of large wind down ramps in those circumstances where such events are realised or likely.
- The corresponding ancillary services payments would incentivise valuable flexible conventional generation capacity to be available when required. As such,

it may also reduce the need for ever increasing level of the MCP to ensure supply reliability when the output of intermittent resources is low.

- By assigning the costs of ramp services to those IGRs whose operating patterns contribute to the ramp events or create a material risk of a ramp event, there would be an incentive for these market participants to either manage these events or improve their dispatchability more generally.
- The introduction of an additional ramp service would not fundamentally alter the NEM design as an energy-only market. Modifying the existing FCAS arrangements would instead represent an incremental solution with limited cost implications for consumers, market participants or AEMO systems.
- Finally, the proposed ability to draw on certain flexibility services in specific 'high risk' system conditions is consistent with AEMO's current operating practice. AEMO now procures local regulation FCAS on a pre-contingent basis when South Australia is at risk of islanding (AEMO 2015a). Ramp reserve services could similarly be procured in circumstances where AEMO judges that large variations in residual load are a real possibility.

The proposed ramp reserve service represents an incremental market design change, but does not address the longer-term problem that conventional generation may no longer be viable in a market increasingly dominated by intermittent generation. Figure 4-1 illustrates the basic principle of the proposal. AEMO would, in the normal course of events, review its wind generation forecast and determine whether there is a significant likelihood of a sustained decline in aggregate wind output, or whether the uncertainty around the wind output forecast is particularly large. Similar to an insurance policy, AEMO would then call for bids for ramp reserve and enable suitable flexible technologies to be on standby to respond in the event that aggregate wind output falls in a sustained manner. If such an event materialised, sufficiently flexible conventional generation (or other suitable technologies) would be available to meet consumer demand.

Figure 4-1. Deployment of ramp reserve ancillary service



Given that payments for the ramp reserve service would be recovered from intermittent generators, there would be limited net price impact on consumers. Furthermore, given that the provision of this service may avoid the price spikes that frequently occur in the context of large wind down ramp events, average prices may be reduced. It is important to note that the introduction of this service would be targeted at specific circumstances where there is material uncertainty about the output of intermittent generators. As such, the role of high NEM prices as a broader indicator of generation capacity shortages would not be affected.

4.4 Conclusions

IGRs cause a range of integration costs to be incurred in the non-intermittent part of the power system, including because of the need to carry additional reserves. From an economic welfare perspective which focuses on minimising the overall system cost of supplying consumers with electricity, integration costs need to be incorporated in any analysis of the costs and trade-offs associated with alternative policy choices. Furthermore, and as is the case with any other economic externality, minimising total system costs requires cost-reflective price signals to be in place, such that IGRs internalise the additional costs they impose on the remainder of the power system.

The NEM Rules do not provide for a consistent framework for ensuring that investors in intermittent generation projects internalise the additional costs that IGRs impose on the power system:

- While some share of regulation costs are currently attributed to 'semi-scheduled' (intermittent) generators, the cost allocation methodology is not aligned with the underlying cost drivers of regulation services: the extent to which (intermittent) generators contribute to the variability and uncertainty of residual load.

- The question of how the conventional flexible generation capacity that is needed to manage large changes in wind and solar generation output or situations where intermittent output is low or zero will be incentivised and paid, and who should bear these costs remains unresolved in the NEM.

As a result, investment in renewable generation in the NEM to date consists entirely of intermittent technologies that impose the largest integration costs on the power system. Looking forward, and given current projections about the scale of planned renewable investment, these costs are expected to be substantial. Allocating at least some share of integration costs to the market participants who cause them will then be fundamental to incentivising efficient investment and behaviour, and for ensuring that the overall system costs in the NEM are minimised, in the interests of consumers.

At a minimum, aligning the incentives of IGRs with the objective of minimising system costs would require allocating the costs of regulation FCAS on the basis of causality; that is, the extent to which (intermittent) generators cause higher regulation costs to be incurred. Over the medium- to longer term, the more material concern is how to ensure that investors in intermittent generation projects internalise the costs of the additional reserves that are needed to cope with large swings in the output of intermittent generators, so as to minimise system costs. At least two high-level options can be considered to achieve this objective:

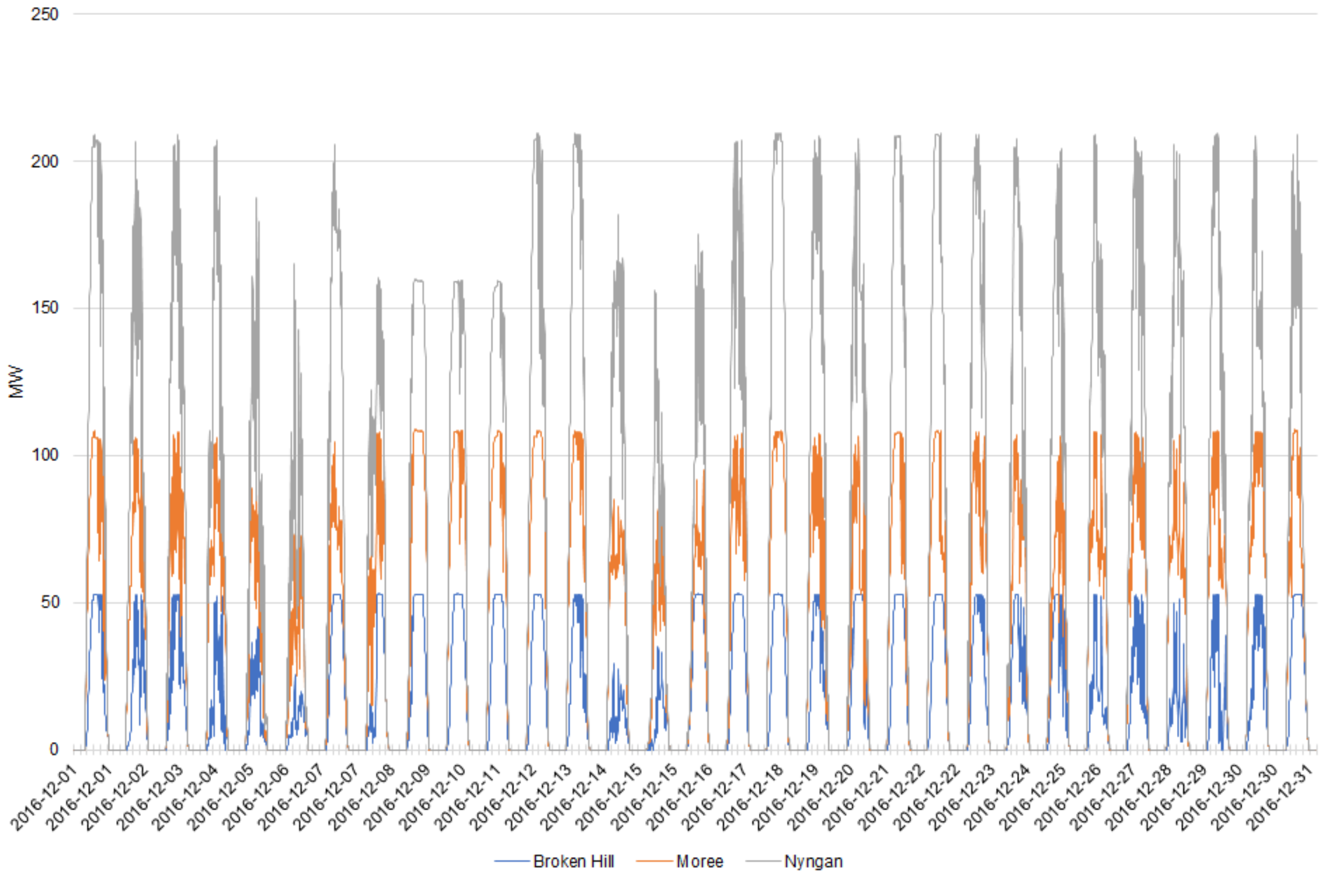
- AEMO's NTNDP sets out an extensive and costly investment program across the Eastern Seaboard grid. Among other things, these augmentations would enable better reserve sharing across the NEM. However, under the NEM Rules, the costs of investments in the shared network would simply be allocated to consumers. This option is then particularly costly, because it provides for no incentives for intermittent generators, whose operational patterns (and locational decisions) give rise to these costs, to minimise them.

- Alternatively, some form of capacity payment system could be introduced to provide an additional financial incentive to conventional generators who are required for system security purposes. Such capacity payments would eliminate the need for a very high MCP and may be needed at some point in the future, but this option would represent a major change to the NEM market design, and would be complex to design and implement. Additionally, and while intermittent generators would inherently receive a low (and declining) capacity credit, any efficient investment signals would likely be muted.

The preferred option is to expand the scope of ancillary services that are currently defined in the NEM to include a ramp reserve service, and to attribute the costs of this service to the market participants who cause them. Such an ancillary service would be designed to address large swings in intermittent output that may challenge system security and give rise to price spikes. Allocating the corresponding costs to IGRs would incentivise intermittent resources to invest in the technologies needed to improve their dispatchability and thereby reduce the additional reserves that are needed. At the same time, payments for flexible generation services would encourage this type of capacity to remain available in the NEM.

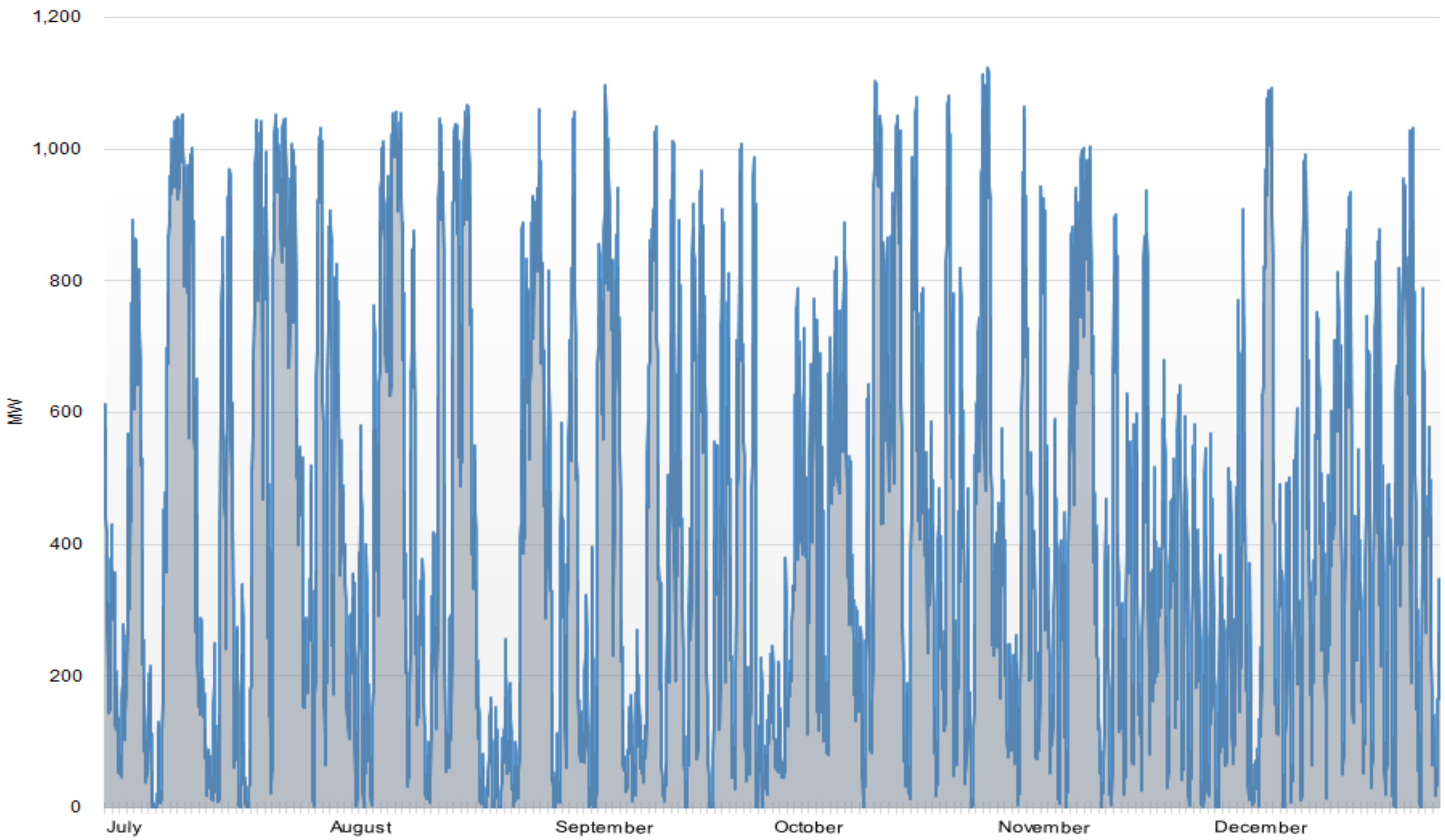
Appendix A Intermittent generation output

Figure A-1. Solar generation ramping behaviour (December 2016)



Source: ARENA data.

Figure A-2. Wind generation output South Australia – August 2016 to December 2016



Source: AEMO data.

Appendix B Ramp reserve services in US power markets

This appendix provides a brief overview of ramp reserve services introduced in other liberalised power markets. Comparisons between wholesale power markets are complicated by different market designs. With the exception of ERCOT, many power markets in the United States differ significantly from the NEM design, including because they clear over longer timeframes, incorporate unit commitment algorithms, incorporate a day-ahead and a real-time market, and incorporate capacity markets.

B.1 MISO

MISO manages the transmission network and energy markets from Montana to Michigan, and Manitoba, as well as portions of Texas, Louisiana, Mississippi, and Arkansas. Unlike ERCOT, where the quantity and trigger for existing contingency reserves has been changed, the Midcontinent Independent System Operator (MISO) has introduced a distinct reserve category to complement its existing regulation and contingency reserve services, referred to as a 'Ramp Capability Product' and comprising a 'Ramp Up' and a 'Ramp Down' service (FERC 2014). The Ramp Capability Product was developed to manage increasing system ramping needs as a result of increasing wind penetration, in particular situations where system ramp capability is inadequate to respond to wind and residual load forecast errors. MISO argued that such events were frequently characterised by significant price spikes caused by a lack of operational ramp capability, rather than a reflecting a reserve shortage as such.

Ramp capability is now procured as an ancillary service in the day-ahead and real-time markets to account for unforecast variations in residual load. Generation resources enabled to provide ramp capacity are held back from providing energy to retain sufficient capacity to achieve required ramp levels in subsequent dispatch intervals. The specific ramp capability requirements are determined on the basis of residual load forecasts and residual load forecasting errors.

B.2 XCel Energy

XCel Energy operating in Colorado has similarly introduced a supplemental category of reserve (referred to as 'Flex Reserve Service') to address increasingly frequent large and unforecast wind (down) ramp events (FERC 2014a, XCel Energy 2016). Flex Reserve consists of excess contingency reserve, as well as online and offline generation that can be deployed within 30 minutes. The amount of Flex Reserve required depends on the current and projected levels of wind resources on the system, and is based on an analysis of wind ramps to identify the steepest 30-minute loss of wind generation embedded in a longer and large wind generation down ramp.

B.3 California ISO

The California Independent System Operator (CAISO) has historically applied dispatch constraints to ensure sufficient conventional generation resources are positioned to meet forecast uncertainty for upward ramp needs (CAISO 2016, 2016a). CAISO has now implemented a flexible ramp product in the real-time market that is intended to ensure that sufficient upward and downward ramp capability is available. This product incorporates both forecast changes in residual demand, as well as a component that accounts for residual demand forecast errors. Loads or generation resources that increase (decrease) the need for ramp capability will be charged (paid) for the flexible ramp product. The cost of ramp capability to cover uncertainty will be allocated to loads and generation resources based on their contribution to this uncertainty.

Unlike the MISO and XCel products, CAISO's flexible ramp product is not classed as an ancillary service, but is instead described as a mechanism for adjusting energy dispatch in a manner that accounts residual load uncertainty. In effect, CAISO re-optimises the system, and dispatches energy out of merit order to preserve ramp capability for a future point in time.

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