Implications of Australian Renewable Energy Mandates for the Electricity Sector

Brian S. Fisher and Sabine Schnittger

BAE Research Report 2016.2

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August 2016

BAEconomics Pty Ltd

ISBN: 978-0-9945697-1-4

Brian S. Fisher and Sabine Schnittger, 2016, *Implications of Australian Renewable Energy Mandates for the Electricity Sector*, BAE Research Report 2016.2, Canberra, August.

BAEconomics Pty Ltd

GPO Box 5447 Kingston, ACT 2604, Australia

Telephone +61 437 394 309; Facsimile +61 2 6239 5864

www.baeconomics.com.au

Foreword

The Minerals Council of Australia has requested that BAEconomics assess the implications of increasing shares of renewable energy in the Australian electric power system for the stability of the system itself and more broadly for the Australian economy as a whole.

The Renewable Energy Target operates alongside other government policies designed to reduce greenhouse gas emissions. Applying multiple policies to achieve one target – a given reduction in emissions by a particular year – is unlikely to be efficient because of the inherent conflicts between multiple policy instruments. The issue addressed in this paper is the narrower one of the implications of increasing shares of renewable energy generation on the overall (system) cost of supplying consumers with electricity. The corresponding challenges are common to all power systems as the share of intermittent generation increases, but the so-called integration costs of mandating greater shares of intermittent technologies are higher in power systems that have been traditionally dependent on thermal generation plants such as Australia's east coast power network.

The value of electricity depends on when (and where) it is generated. The electricity that can be supplied by a wind generator at a low cost is not 'cheap', if the output is mostly available at night when demand is low, supply is plentiful, and the value of electricity to consumers is also low. Conversely, the electricity that can be supplied by a gas turbine at a high cost is not 'expensive', if it can be called on to generate during peak demand periods when the system is stretched to capacity and the value of electricity to consumers is very high. Levelised cost comparisons between different generation technologies are then largely meaningless because they implicitly assume that the electricity generated from different sources has the same value. The empirical observation is that the market value of intermittent renewables is relatively low and further declines as their market share rises. Notwithstanding projected cost reductions for these technologies therefore, the subsidies required to deploy increasing shares of intermittent renewables can be expected to increase disproportionately.

Our aim in this report is to review some of the key issues facing the power sector as governments strive to achieve higher renewable energy targets.

Dr Brian Fisher
Managing Director
BAEconomics Pty Ltd
August, 2016

Table of contents

Executive summary and conclusions

This report focuses on the cost and value implications of mandating increasing shares of intermittent renewable generation technologies – such as wind and solar PV – in electric power systems, including in Australia.

Consumers' demand for electricity and power systems

Consumers' demand for electricity varies over timescales of seconds, minutes and hours, depending on whether a day is a working day, a weekend day or a holiday, and by season. During the working week, the demand for electricity generally peaks relatively early in the morning, declines somewhat during the day and peaks again in the early evening, and is generally lowest in the early hours of a new day. There are also shifts in the timing of peaks over different days of the week. Such load profiles are overlaid with temperature-related variability arising from the use of air-conditioning and heating appliances.

The power systems that supply consumers with electricity have evolved are complex. Such systems must be administered by a system operator whose role it is to coordinate the operation of all power stations in a very precise way. This coordination task requires that the electricity supplied by power stations exactly equals the electricity that consumers demand by turning on electrical appliances at all times, and that power stations furthermore operate in such a way that the 'technical envelope' of the system is not violated. In circumstances where electricity demand and supply are not balanced or technical constraints are breached, the operation of a power system is no longer 'secure'. Unless the system operator takes immediate action to address a particular issue or contingency, the power system may collapse and black-outs will result. Black-outs, where some or all parts of an electricity system are no longer supplied with electricity are extremely costly for the affected customers, and represent events that a system operator will try to avoid at a high cost.

In most developed countries, including in Australia, the electricity generation sector has been liberalised to enable private sector entities to generate electricity, and wholesale markets have been established where electricity is traded. Thus the National Electricity Market (NEM) operates across the Eastern Seaboard power system, while the Wholesale Electricity Market (WEM) operates in south-west Western Australia. While the designs of the NEM and the WEM differ in important respects, both wholesale markets post a single market-clearing electricity spot price for each half-hour of the day. That spot price reflects the intersection of demand and supply in a given half-hour, so that the incremental cost of producing the electricity in that half-hour equals its value to customers.

Electricity demand varies over short timescales, but wholesale electricity cannot generally be stored cost-effectively at present. This has an important implication for electricity wholesale prices, namely, that these prices have a very significant temporal dimension. In the NEM, half-hourly spot prices are typically low during off-peak periods (although they may fall as low as zero or below zero in some instances), but may rise to hundreds of dollars per MWh at high levels of demand, and up to the market price cap of currently $14,000 per MWh. Such price variations reflect the fact that the cost of supplying an additional increment of electricity varies a great deal for different levels of demand, reflecting the type of generation technology that is dispatched and the availability of additional generation capacity. Overnight, for instance, when electricity demand is low and there is ample generation capacity to supply it, a low spot price may reflect the 'marginal cost' of the coal-fired baseload plants that are operating. In periods when demand is higher and peaks, spot prices rise as increasingly expensive mid-merit and peaking power stations with higher marginal costs are dispatched to operate. As demand rises, the output of power stations that are available to generate therefore becomes increasingly valuable.

Integration costs of intermittent generation technologies

Whenever a particular generation technology is added to and integrated with the operations of a power system, other generation and network components of that system are affected in some way. As a result, total system costs may increase or decrease. The concept of integration costs of a specific generation technology then captures the effect that deploying that technology causes costs elsewhere in the power system. However, while these costs in principle arise for other types of generation technologies, what distinguishes the integration costs of wind and solar PV technologies is not their existence, but their size. Specifically, these technologies interact differently with the power system than is the case for conventional plant that can be dispatched, and are far more difficult to integrate, particularly at high levels of penetration (or shares of generation capacity or demand).

In one way or another, the high integration costs of wind and solar PV technologies derive from the fact that these renewable technologies operate in a manner that is fundamentally different from conventional generation technologies. The electricity output from these technologies is 'intermittent'; that is, they are not continuously available to generate electricity because of external factors that cannot be controlled (such as the strength of wind or the amount of sunlight). There are therefore significant limitations in the extent to which intermittent technologies can be dispatched by the system operator, and therefore the extent to which they can usefully be deployed to meet demand at any given time of the day or night. When it reaches a certain point, the intermittent production of electricity poses a threat to the security of a power system because supply and demand cannot be balanced using intermittent resources alone. The deployment of intermittent renewable generation (IRG) resources then implies that specific actions need to be taken – and corresponding costs incurred – in the non-intermittent (or 'residual') part of the power system. In this context, integration costs are then defined as all additional costs in the residual part of the power system when IRG resources are deployed.

The integration costs of IRG technologies into electric power systems consist of three approximately additive components. Balancing costs occur because the supply from IRGs is uncertain until realisation and forecasting errors therefore arise. The corresponding costs take the form of adjustments that have to be made to the least-cost dispatch schedule of dispatchable generators, and the need to hold additional short-term reserves. Profile costs are caused by the variability and particular intertemporal generation profile of IRG technologies, which is often not well correlated with demand. These attributes imply that while IRG resources contribute some electricity, they hardly reduce the need for the overall capacity that needs to be maintained in a power system. Profile costs take the form of flexibility costs that arise because of the specific operational requirements placed on dispatchable generators, utilisation or back-up costs that reflect the need to maintain significant conventional generation capacity (even if it is hardly used), and overproduction costs when IRG technologies need to be constrained down or off because they produce more electricity than is demanded by consumers. Grid costs arise from the specific location of IRG resources. These costs that arise if additional network investment is necessary to accommodate IRG resources, for instance if high quality IRG sites are located far from demand centres, and additional transmission losses and congestion costs, for instance, if the additional output from renewable generators constrains existing transmission infrastructure.

Looking beyond integration costs, conventional generators – particularly large coal-fired plants – have certain inherent characteristics that contribute to the security of the power system, but that are presently not generally provided by IRG resources. When conventional generators operate they provide 'inertia'; that is, they contribute to the ability of the power system to 'ride through' fault events and limit system frequency excursions. As conventional generators are displaced by non-synchronous (wind and solar) generation technologies, the overall reduction in inertia tends to increase the frequency and magnitude of power system disturbances, so that the power system becomes more vulnerable to fault events unless some other action is taken.

Integration costs depend on the characteristics of IRG technologies, but also on the flexibility of the particular power system into which they are being integrated. Thus integration costs tend to be higher in power systems dominated by less flexible thermal generation resources (as is the case in Australia) than in predominantly hydroelectric systems. These costs also tend to be less in larger and interconnected power systems, than in smaller systems with weak interconnections. Integration costs are therefore system-specific.

The components that constitute the integration costs of IRG resources – balancing, profile and grid costs – are not constant parameters, but are functions of many system properties. A review of the literature nevertheless reveals a number of important trends that apply across predominantly thermal power systems. The most important of these is that integration costs increase with the penetration of IRG resources.

At low levels of penetration, the integration costs of intermittent renewables may be low or even negative. In these circumstances, the additional balancing and profile costs are outweighed by the fuel cost savings from wind and solar PV resources. Overall, integration costs are considered to be relatively small at penetration levels of up to 10 per cent.

Even allowing for adaptation in the generation mix to account for the uncertainty and variability of intermittent renewables, however, the integration costs of IRG technologies can become very high at high penetration rates. When wind penetration reaches 30 to 40 per cent, balancing costs are estimated to be AU$ 6 per MWh of renewable energy generated, while profile costs are in the range of AU$ 30 per MWh of renewable energy generated. Profile costs – which arise from the need to maintain additional costly generation capacity in the system to manage the significant output variability of intermittent resources – are significantly higher than balancing costs. Overall, and allowing for long-term changes in the generation mix, integration costs are estimated to be in the range of AU$ 37 to AU$ 53 per MWh when wind penetration reaches 30 to 40 per cent.

System value of intermittent renewables

Given that the price of electricity varies a great deal over time and that different generators have differing intertemporal operating profiles, the marginal value of different generation technologies in a power system also does not coincide. The optimal deployment for each generation technology that minimises costs to consumers therefore also varies, depending on its value in the power system. Government policies that set a targeted level of IRG output as part of a renewable energy mandate without considering the value of the electricity produced by that technology are therefore almost certainly inefficient, and will increase costs to consumers at higher levels of IRG technology penetration.

Unlike what is commonly claimed by proponents of renewable energy mandates, it is not the case that IRG technologies will invariably become 'competitive' as the stand-alone costs of these technologies continues to fall. Levelised cost of electricity (LCOE) comparisons between IRG and other generation technologies are misleading because they fail to consider the value of IRG resources within a power system. From a social welfare or competitiveness perspective, it is irrelevant whether or not the LCOE of wind or solar technologies is below or above that of other generation technologies; what matters instead is a given technology's cost relative to its value. Thus, the electricity that can be supplied by a wind generator at a low levelised cost is not 'cheap', if the output is mostly available at night when demand is low, supply is plentiful, and the value of electricity to consumers is also low. Conversely, the electricity that can be supplied by a gas turbine at a very high levelised cost is not 'expensive', if it can be called on to generate during peak demand periods when the system is stretched to capacity and the value of electricity to consumers is very high. Simplistic levelised cost comparisons between different generation technologies are therefore largely meaningless because they implicitly assume that the electricity generated from different sources has the same value in the power system.

In a well-functioning liberalised power system, the value of a particular generation technology is reflected in the market prices that it earns from producing electricity. In power systems with high shares of intermittent renewables, technologies such as wind consistently earn less than overall weighted-average spot prices, indicating a 'value factor' that is less than one. The observation that the value factor of IRG technologies strictly declines as their share in a power system increases is referred to as the 'self-cannibalisation effect'. It arises because renewable technologies tend to produce disproportionately during times when the electricity price is low, and because their output is correlated. As more capacity is added to the system, IRG technologies will tend to generate at similar times, so that there is increasingly an abundance of electricity at these times, which in turn leads to lower prices, a lower system value, and a lower value factor.

The exact magnitude of the value decline of IRG resources is system-specific. However, the studies that have been undertaken commonly find that in predominantly thermal power systems, at high penetration rates (such as 20+ per cent for wind or 10+ per cent for solar, intermittent technologies produce the least-value electricity. At such penetrations, integration costs play an increasing and material role. Thus intermittency increasingly reduces the market value of renewable generation such that, on average, one MWh from wind power is worth increasingly less than one MWh from a conventional power station or other dispatchable source. The implication is that the greater the share of renewables in a power system, the lower its value, and the higher the overall system cost of supplying consumers with electricity.

Conclusions

As has also been noted by the International Energy Agency, the economic challenge of integrating wind and solar technologies in a power system is reflected in their declining value. As the penetration of these renewables increases, the level of support to meet deployment targets also rises. System and market integration then become a critical priority for renewables policy.

There are a number of studies which suggest that high shares of renewable generation are technically feasible in the Australian electricity market, albeit at a high cost. Achieving these targets will require the deployment of new generation technologies and forms of storage, as well as a greater emphasis on demand side management. However, few such studies consider the market context in which electricity markets operate and whether, given current market structures, financing models exist that will allow the necessary investment both in increasing renewable capacity and the supporting generation and storage technology necessary to ensure that system reliability is maintained. In the light of the recent experience in South Australia's electricity market Nelson and Orton (2016) conclude that a 'root-and-branch' review of energy market design and governance is required – to consider how best to decarbonize Australia's electricity supply across the generation, transmission, distribution, and retail components of the supply chain while maintaining supply security, efficient pricing, and appropriate risk allocation.' Such a review seems essential if further increases in the RET are contemplated given that substantial new investment in the power system overall will be required to achieve such targets while maintaining a reliable power system.

1 Introduction

1.1 Context

There have been increasing calls for a greater share of electricity generation to be sourced from renewable technologies such as solar and wind. While they differ in terms of their precise targets, all of the major parties envisage a renewable energy target (RET) where a share of electricity generated in Australia would need to come from renewable generation facilities, as well as other policies targeted at the electricity sector. For example, the Australian Labor Party in the run up to the recent federal election stated its intention to implement a reduction target of net zero emissions by 2050, partly facilitated by a further target of 50 per cent renewable energy by 2030 in the event that it won government. The Australian Greens announced a desire to reach at least 90 per cent renewable energy generation by 2030 to be achieved by increasing the RET and increasing clean energy finance to $30 billion over 10 years. The Greens' policy also included a promise of $2.9 billion over five years in support of homes and business uptake of renewable energy storage units. The current Coalition government implemented a 23.5 per cent RET by 2020 in its previous term.

In one way or another, therefore, all of these policies would accelerate moves toward increasing the share of electricity generated from renewables and correspondingly reduce the share of conventional (thermal) generation, in particular generation from coal. Given the reliance of the Australian economy on energy as a vital input, the effects of these policies – in terms of their costs and the corresponding impacts on prices and, more broadly, on the reliability of electricity supply – are potentially far-reaching.

1.2 Structure of this report

This paper describes the costs and broader implications of the RET for the electric power system:

- Section 2 describes the operations of electrical power systems and the wholesale power markets that operate around these systems;
- Section 3 describes the RET and how it interacts with the power system;
- Section 4 describes the concept of integration costs that arise in integrating intermittent renewable technologies such as wind and solar into a power system;
- Section 5 describes the specific integration costs of intermittent renewable technologies;
- Section 6 comments on the implications of integration costs for a competitiveness or welfare analysis of power systems;
- Section 7 describes the implications for electricity price volatility of increasing shares of renewable generation in power systems dominated by thermal generators; and
- Section 8 discusses some of the implications of including an increasing share of renewables in Australia's electricity markets.

2 Electrical power systems

The increased deployment of small- and large-scale renewable energy technologies creates material challenges for the operation of electrical power systems. Understanding these challenges requires an appreciation of the characteristics of such systems and how they are managed. This section provides an overview of the essential features of electrical power systems and the wholesale market arrangements that overlay them in Australia.

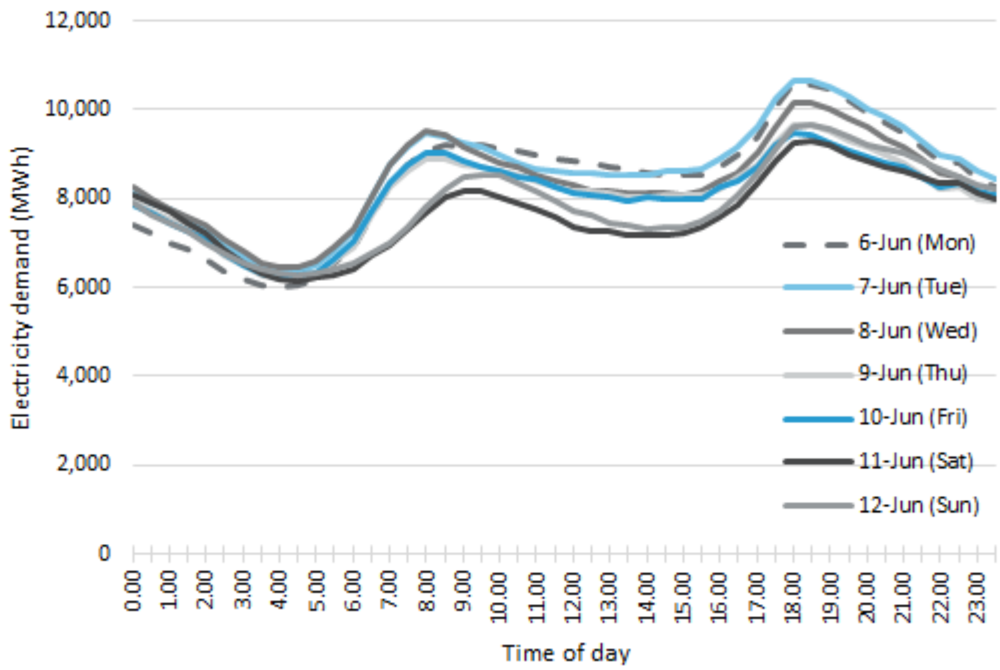
2.1 Balancing demand and supply

Consumers' demand for electricity varies over timescales of seconds, minutes and hours, depending on whether a day is a working day, a weekend day or a holiday, and by season. During the working week, the demand for electricity generally peaks relatively early in the morning, declines somewhat during the day and peaks again in the early evening, and is generally lowest in the early hours of a new day. Figure 2-1 shows a series of such daily demand or 'load' profiles for NSW in early June of this year. It shows daily variations in minimum and maximum demand, as well as the shift in the timing of peaks over different days of the week. Such load profiles are overlaid with temperature-related variability arising from the use of air-conditioning and heating appliances.

Consumer demand profiles are also affected by variability arising from the installation of rooftop photovoltaic (PV) generating installations on the part of households. Rooftop PV installations are installed 'behind the meter'; their electricity output is not directly observable by the system operator. From an aggregate perspective, the existence of rooftop PV installations therefore manifests itself as a reduction in demand at certain times during daylight hours. 'Residual' electricity demand during certain times of the day is therefore reduced.

The power systems that supply consumers with electricity have evolved over many years and are complex. In Australia, the two largest systems operate across Australia's Eastern Seaboard and the South West Interconnected System of Western Australia (SWIS). Power systems comprise a large number of interconnected components, including many different types of network elements and power stations. The operation of a such a system must be administered by a system operator whose role it is to coordinate the operation of all power stations in a very precise way. This coordination task requires that the electricity supplied by power stations exactly equals the electricity that consumers demand by turning on electrical appliances at all times, and that power stations furthermore operate in such a way that the 'technical envelope' of the system is not breached. The corresponding technical constraints require, among other things, that frequency and voltage across the system remain within 'normal' limits and all equipment operates within its technical ratings. In circumstances where electricity demand and supply are not balanced or technical constraints are violated, the operation of a power system is no longer 'secure'. Unless the system operator takes immediate action to address a particular issue or contingency, the power system may collapse and black-outs will result. Black-outs, where some or all parts of an electricity system are no longer supplied with electricity are extremely costly for the affected customers, and represent events that a system operator will try to avoid at a high cost.

Figure 2-1. Electricity load profiles for NSW – 6 to 12 June 2016



Source: AEMO data.

The Australian Energy Market Operator (AEMO) is the system operator for the Eastern Seaboard power system and the SWIS. AEMO maintains these power systems in a secure operating state by 'dispatching' (instructing to operate) 'conventional' – coal- or gas-fired or hydroelectric – power stations at a defined level of electrical output so that the instantaneous power supplied to the system exactly matches aggregate electricity demand, and that technical constraints are not breached. That task is complicated by the variability in electricity demand and the fact that forward demand projections are inherently uncertain. There is also always the possibility of contingencies arising from unplanned outages and faults, either of a network element or a power station, which can also compromise the security of the power system. Over short timeframes, the secure operation of a power system therefore also requires that AEMO can call on various 'ancillary services' that are needed to deal with a range of system events or contingencies, and that a certain quantity of operational reserve is available to be called upon. To date in Australia, these ancillary services are generally provided by conventional power stations, and to a lesser extent by load (customers).

2.2 Power stations and the merit order

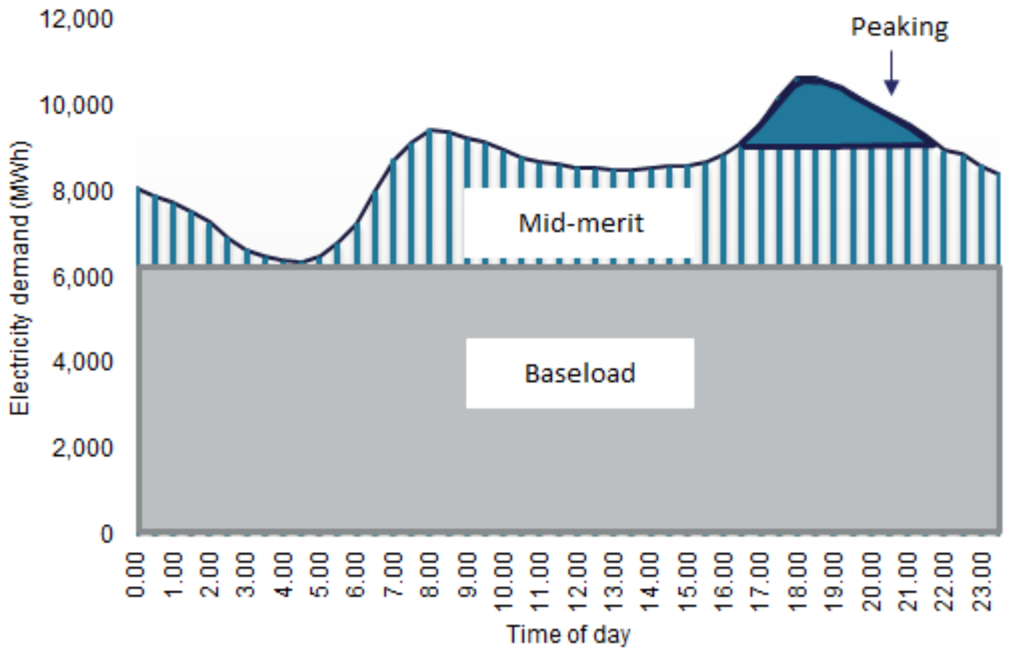
The task of matching time-varying electricity demand and supply at all times and in a manner that is least-cost for consumers requires a mix of power stations. Conventional coal-or gas-fired power stations differ according to their operating capabilities and cost characteristics, and play different roles in a power system corresponding to a dispatch hierarchy that depends on the level of demand:[1]

- ‘Baseload’ plants have high capital costs and are relatively inflexible in terms of their ability to vary their output, but are also cheap to run, in terms of their cost of producing an additional unit of electricity (as measured in $ per megawatt hour of electricity generated ($/MWh). Baseload plant generally operate 24 hours a day on all days and meets the minimum level of electricity demand. Given that Australia is endowed with substantial, high-quality coal resources, baseload power stations on the Eastern Seaboard are black- or brown coal plants.
- ‘Mid-merit’ or ‘intermediate’ plants additionally operate at times when electricity demand is higher than the daily minimum, sometimes referred to as ‘shoulder’ periods. Such plants are capable of ‘ramping’ their output up or down more quickly than baseload plants to match changing electricity demand, but they also tend to be more costly to operate. Mid-merit power stations can be coal- or gas-fired.
- ‘Peaking’ plants are additionally needed to generate to meet demand when it is at its highest, for instance, when electricity consumption from air-conditioning or heating appliances spikes. Peaking plants are typically gas- or oil-fired, and can change their output very quickly. Although the capital costs of such plants are relatively lower, such plants are very costly to operate. Peaking plants are nevertheless essential for system security. They are, for instance, required to balance electricity demand that is changing rapidly or to compensate for contingencies elsewhere in the power system and thereby prevent the system from collapsing.

In a typical power system, baseload, mid-merit and peaking plants make up the so-called ‘merit order’ of power stations, whereby power stations are ranked in order of their $/MWh generating costs. Figure 2-2 presents a stylised example of a daily demand curve with three classes of generators serving the load. Around 6,000 MWh can be served from baseload generators that run continuously and offer the lowest $/MWh cost. As demand increases during the day, higher cost mid-merit generators are dispatched to match the changing load profile. Depending on how flexible these mid-merit plants are, it may also be necessary to dispatch fast-response (peaking) plants. In the example in Figure 2-2, peaking plants are dispatched during the evening peak from 5pm to 10pm.

[1] The following discussion abstracts from hydroelectric generating plant, whose operations differ somewhat from thermal generating plant, but can operate as baseload, mid-merit or peaking plant, depending on the qualities of the underlying water resource.

Figure 2-2. Least-cost generation dispatch



Source: AEMO data.

In principle, and unless there are specific constraints that need to be accommodated, a system operator will always dispatch power stations from least cost to highest cost in order to minimise the cost of meeting consumer demand. The addition of renewable resources such as wind turbines to the generation mix then changes the conventional merit order. Wind turbines incur capital costs to build, but their generating costs are very low and close to zero. When they are available (that is, when the wind is blowing), wind turbines are therefore always located at the bottom of the merit order and have operational priority such that they displace (higher cost) conventional plant.

2.3 Electricity wholesale markets and prices

In most developed countries, including in Australia, the electricity generation sector has been liberalised to enable private sector entities to generate electricity, and wholesale markets have been established where electricity is traded. Thus the National Electricity Market (NEM) operates across the Eastern Seaboard power system, while the Wholesale Electricity Market (WEM) operates across the SWIS. While the designs of the NEM and the WEM differ in important respects, both wholesale markets post a single market-clearing electricity spot price for each half-hour of the day. That spot price reflects the intersection of demand and supply in a given half-hour, so that the incremental cost of producing the electricity in that half-hour equals its value to customers.

Electricity demand varies over short timescales, but wholesale electricity cannot generally be stored cost-effectively.[2] This has an important implication for electricity wholesale prices, namely, that these prices have a very significant temporal dimension.[3] In the NEM, half-hourly spot prices are typically low during off-peak periods (although they may fall as low as zero or below zero in some instances), but may rise to hundreds of dollars per MWh at high levels of demand, and up to the market price cap of currently $14,000/MWh. Such price variations reflect the fact that the cost of supplying an additional increment of electricity varies a great deal for different levels of demand, reflecting the type of generation technology that is dispatched and the availability of additional generation capacity. Overnight, for instance, when electricity demand is low and there is ample generation capacity to supply it, a low spot price may reflect the 'marginal cost' of the coal-fired baseload plants that are operating. In periods when demand is higher and peaks, spot prices rise as increasingly expensive mid-merit and peaking power stations with higher marginal costs are dispatched to operate. As demand rises, the output of power stations that are available to generate therefore becomes increasingly valuable.

[2] The exception is hydro-dominated power systems (such as the Tasmanian system) where water stored in reservoirs effectively represents a form of electricity storage (assuming adequate supplies of water are available).

[3] The existence of network constraints means that electricity wholesale prices also have a geographical dimension, although these are not necessarily explicitly priced. In the NEM, geographical price differences may emerge across NEM regions, while intra-regional network constraints do not give rise to price differences but are managed via command and control instruments. The WEM does not post geographical price differences.

3 The renewable energy target

In liberalised electricity wholesale markets such as the NEM and the WEM, decisions about the type, timing and location of generation investments are the responsibility of market participants, and occur on the basis of wholesale market price signals.[4] The objective of these reformed governance arrangements is to enable the private sector to take on the considerable expenditures and associated financial risks of making generation investments. Their implementation reflected a widespread recognition that the hitherto government-owned and -run electricity supply industry was inefficient, and imposed significant unnecessary costs on consumers.

3.1 Government investment mandates

In this market context, government policies such as the RET that mandate the share of wholesale electricity that is to be generated from renewable sources translate into a requirement to build additional (renewable) power stations that is disconnected from whether that additional capacity and generation technology is needed to meet electricity demand, and whether the corresponding expenditures are therefore warranted. Both the NEM and the WEM have, for some years, been characterised by significant surplus generation capacity as growth in electricity consumption has moderated or declined, so that no new generation investment was required to meet consumers' electricity demand. Notwithstanding that excess capacity, as of 2015, government policies to mandate generation investment have resulted in new large-scale wind generation capacity in the NEM of almost 3,500 MW, and in more than 360 MW of mostly wind capacity in the WEM. Wind generation is not commercially viable in either market, and requires substantial subsidies to be deployed at scale. At the same time, the subsidies paid under the SRES have supported the installation of around 2.4 million small-scale facilities (in the main rooftop PV installations) since 2001. The RET therefore represents a form of intervention that has resulted in large amounts of renewable generation capacity being commissioned that is both costly and surplus to requirements. This mandated investment therefore represents a real opportunity cost to the Australian economy.

3.2 Renewable generation subsidies

The subsidies paid to power station developers and households under the RET are recovered from electricity consumers. In the case of the LRET, the subsidies take the form of 'large-scale generation certificates' (LGCs) that are equivalent to 1 MWh of renewable electricity. Renewable generators earn one LGC for each MWh of electricity they generate. The Clean Energy Regulator (CER) calculates an annual 'renewable power percentage' (RPP) that mandates how many LGCs electricity retailers must surrender each year to meet their LRET obligation. Similar arrangements

[4] In the NEM, for instance, where power stations recover their costs from revenues earned in the wholesale market, rising spot prices generally signal an impending need for new generation capacity and will encourage new entry.

apply for the SRES, whereby CER determines an annual 'small-scale technology percentage' and electricity retailers are required to surrender a corresponding number of 'small-scale technology certificates' (STCs). Electricity retailers then pass the costs of LGCs and STCs through to consumers who pay these subsidies as a component of their electricity bills.

The design of the LRET and the SRES arrangements implies that while the subsidies directed toward achieving the RET originate from a government mandate, they are paid for by electricity consumers and collected by third parties. These subsidies therefore do not appear in government accounts and their magnitude is not transparent. Estimates of total subsidies must instead be inferred from LGC and STC prices published by proprietary trading platforms, and the limited information provided by CER. In 2016, for example, CER determined that retailers would need to surrender 21.43 million LGCs so as to ensure that 21.43 TWh of electricity would be generated from renewable energy sources. Given that LGCs appear to have traded in the $80/MWh range over the past six months (and assuming that this will continue to be the case), the current LRET obligation would imply direct subsidies to the large-scale renewable generation sector of around $1.7 billion in 2016 alone.

4 Wholesale market cost implications of the RET

Electric power systems exist to provide consumers with electricity. Irrespective of how they are organised – in the form of a liberalised market such as the NEM and the WEM, 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. From a public policy (welfare maximising) perspective, what is therefore relevant for assessing the impact of renewable energy mandates such as the RET is their overall effect on the system cost of meeting consumer demand. As set out in the following, the deployment of intermittent renewable generation technologies causes significant so-called 'integration costs' in the electric power system.

4.1 Integration costs of intermittent generation technologies

An economic welfare analysis of a power system focuses on minimising total power system costs, which comprise all costs associated with meeting electricity demand, including investment costs and the discounted life-cycle variable cost of all plant, grid infrastructure and storage systems (Ueckerdt et al. 2013). All generation technologies incur different combinations of investment and variable costs over their life-cycle. For any given generation technology, these costs can be aggregated to derive the annualised average discounted life-time cost or 'levelised cost of electricity' (LCOE) per MWh of electricity generated. The total system cost of a power system therefore includes the LCOEs of all generation technologies operating in that system.

Whenever a particular generation technology is added to and integrated with the operations of a power system, other generation and network components of that system are affected in some way. As a result, total system costs may increase or decrease. The concept of integration costs of a specific generation technology then captures the effect that deploying that technology causes costs elsewhere in the power system. However, while these costs in principle arise for other types of generation technologies, what distinguishes the integration costs of wind and solar PV technologies is not their existence, but their size (Hirth et al. 2016). Specifically, these technologies interact differently with the power system than is the case for conventional plant that can be dispatched, and are far more difficult to integrate, particularly at high levels of penetration (or shares of generation capacity or demand).

In one way or another, the high integration costs of wind and solar PV technologies derive from the fact that these renewable technologies operate in a manner that is fundamentally different from conventional generation technologies. The electricity output from these technologies is 'intermittent'; that is, they are not continuously available to generate electricity because of external factors that cannot be controlled (the generator cannot control the strength of the wind or the amount of sunlight). There are therefore significant limitations in the extent to which intermittent technologies can be dispatched by the system operator, and therefore the extent to which they can usefully be deployed to meet demand. When it reaches a certain point, the intermittent production of electricity poses a threat to the security of a power system because supply and demand cannot be balanced using intermittent resources alone. The deployment of intermittent renewable generation (IRG) resources then implies that specific actions need to be taken – and corresponding costs incurred – in the non-intermittent (or 'residual') part of the power system. In this context, integration costs are then defined as all additional costs in the residual part of the power system when IRG resources are deployed (Ueckerdt et al. 2013).

Integration costs depend on the characteristics of IRG technologies, but also on the flexibility of the particular power system into which they are being integrated. Thus integration costs tend to be higher in power systems dominated by less flexible thermal generation resources (as is the case in Australia) than in predominantly hydroelectric systems. These costs also tend to be less in larger and interconnected power systems, than in smaller systems with weak interconnections. Integration costs are therefore system-specific.

Irrespective of their size, however, the existence of integration costs means that a focus on the stand-alone cost of IRG resources understates their opportunity cost when such technologies are added to an existing power system. The concept of a 'system LCOE' of an IRG technology therefore includes the LCOE metric, but additionally includes all other economic costs attributable to that generation technology as it is deployed in a power system (Hirth et al. 2016). Specifically, in the case of IRG technologies such as wind and solar PV, the system LCOE of these technologies is the sum of the stand-alone LCOE of the generation technology and the integration cost per MWh of electricity generated. These costs need to be accounted for when calculating the total system costs of meeting consumers' demand and determining the least-cost mix of generation technologies.

4.2 Intermittency of wind and solar PV generation technologies

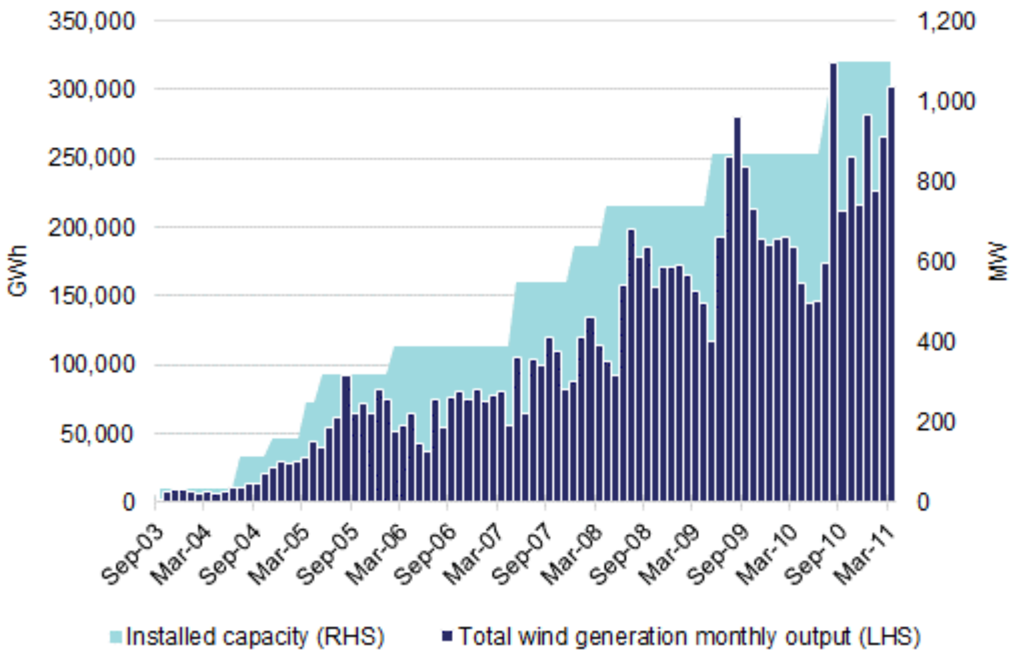
In Australia and in other electricity wholesale markets with renewable energy mandates, new large-scale renewable generation capacity has overwhelmingly taken the form of wind generation, while households have installed large numbers of small-scale solar PV installations. Both wind and solar PV are IRG technologies that give rise to integration costs in the residual power system because of:

- the extent of variability of the supply of electricity from these resources;
- the degree of uncertainty as to how much electricity these resources will supply until realisation; and
- the often distant location of productive renewable energy sites from demand centres and existing infrastructure.

4.2.1 Generation from wind

Whereas conventional generating plant can be dispatched to produce a defined level of electricity, the output of wind turbines varies with fluctuating wind speeds and can only be controlled partially (Wiser et al. 2011). Variations in output can occur over multiple time scales ranging from short-term sub-hourly fluctuations to diurnal, seasonal, and inter-annual fluctuations, and their patterns are highly site- and region-specific. For instance, Figure 4-1 shows total wind generation measured in gigawatt hours (GWh) on the left-hand side (LHS) and in terms of installed capacity on the right-hand side (RHS) in South Australia. There is a seasonal pattern to output, with the highest output generally occurring during winter months, while prominent heatwaves cause a significant decline in monthly output (AEMO 2011a).

Figure 4-1. South Australian total wind generation – September 2003 to March 2011



Source: AEMO 2011a.

The aggregate output of wind farms may change dramatically over multiple hours; very sudden, large drops in output are also possible during high wind conditions when wind turbines cut out. Moreover, and although improvements in forecasting accuracy have been achieved, system operators' ability to predict the output of wind turbines is moderate. In particular, the ability to predict wind power output over forecasting horizons from hours to days is limited.

The characteristics of wind generation can be managed to an extent. The variability of aggregated wind power output diminishes with the geographical dispersion of wind turbines. Control systems at wind turbines can be used to reduce power output fluctuations, albeit at the cost of output reductions or 'spilling' wind. The ability to lower the output of wind generators also gives the system operator a degree of control over their operations in a power system.[5] Notwithstanding the measures that can be taken to predict and control the output of wind turbines, however, from the perspective of operating a secure and reliable power system, wind power variability and uncertainty pose material challenges, particularly at higher penetrations.

To illustrate these challenges, Figures 4-2, 4-3 and 4-4 show some aspects the intermittency of wind output for the South Australian region of the NEM where the greatest share of wind capacity has been deployed to date. Figure 4-2 shows the percentage of installed wind capacity that was available to generate during the top 10 per cent of demand periods in the summer and winter of

[5] In the NEM, such plants are classed as 'semi-scheduled': their output can be restricted in some circumstances, but they cannot be dispatched to meet system requirements.

2014-15, respectively. As noted previously, in circumstances where demand is at its highest, most or all power stations in a system are needed to operate to meet demand and maintain the security of the power system. During the summer top demand periods, wind generation never exceeded 81.5 per cent of registered capacity. Fifty per cent of the time, a little more than a quarter (26.2 per cent) of wind capacity was available to generate. About 3 per cent of the time, wind generation was 5 per cent or less of registered capacity. During the winter top demand periods, wind generation never exceeded 91.4 per cent of registered capacity. Fifty per cent of the time wind generation was around a third (33.8 per cent) of registered capacity. About 12 per cent of the time, wind generation was 5 per cent or less of registered capacity.

The significance of these variations in wind output is that the addition of intermittent wind generation capacity does not imply that conventional generation capacity can be retired. The need to balance demand and supply at all times instead means that significant generation capacity must be maintained in the power system to cope with events where wind output is low and the power system would otherwise collapse. This represents a cost to the system because dispatchable capacity of some form (whether it be traditional thermal generators or some form of storage such as pumped hydro or batteries) must be maintained ready for use.[6]

Figures 4-3 and 4-4 illustrate a different aspect of wind variability – the significant rates of change in output over short timeframes. The figures show the maximum changes in wind turbine output that have been recorded in one of three South Australian regions (the Mid-north area, Figure 4-3) and in South Australia as a whole (Figure 4-4) over five-minutes, 30-minutes and 60-minutes. For instance, Figure 4-3 shows that in the Mid-north area in 2014-15, the maximum increase in electricity production from wind turbines within a 5-minute period was 180 MW (20 per cent of installed wind capacity) and the maximum decrease within a 5-minute period was 289 MW (33 per cent of installed capacity). Figure 4-4 shows that in South Australia as a whole, the maximum increase over the same timeframe was also 180 MW (12 per cent of aggregate installed wind capacity), and the maximum decrease was 240 MW (16 per cent of aggregate capacity). A comparison of the regional (Mid-north) and the overall South Australian rates of change shows that:

- variations in realised wind output increase over longer timeframes;
- variations in wind output differ year-on-year even if wind capacity overall remains unchanged; and
- the output variations from wind turbines aggregated across a larger region are lower in absolute terms than variation from individual areas, reflecting the effects of spatial diversification.

Sudden changes in the supply of electricity from wind turbines challenge the ability of the system operator to balance demand and supply, and require additional operating reserves to be deployed at a cost to the overall power system.

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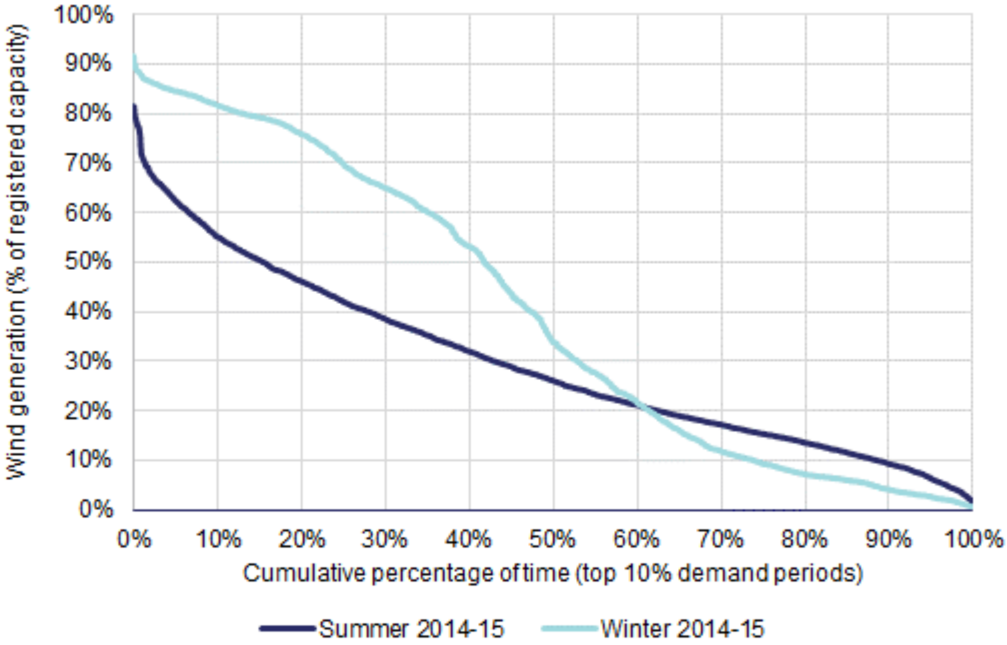
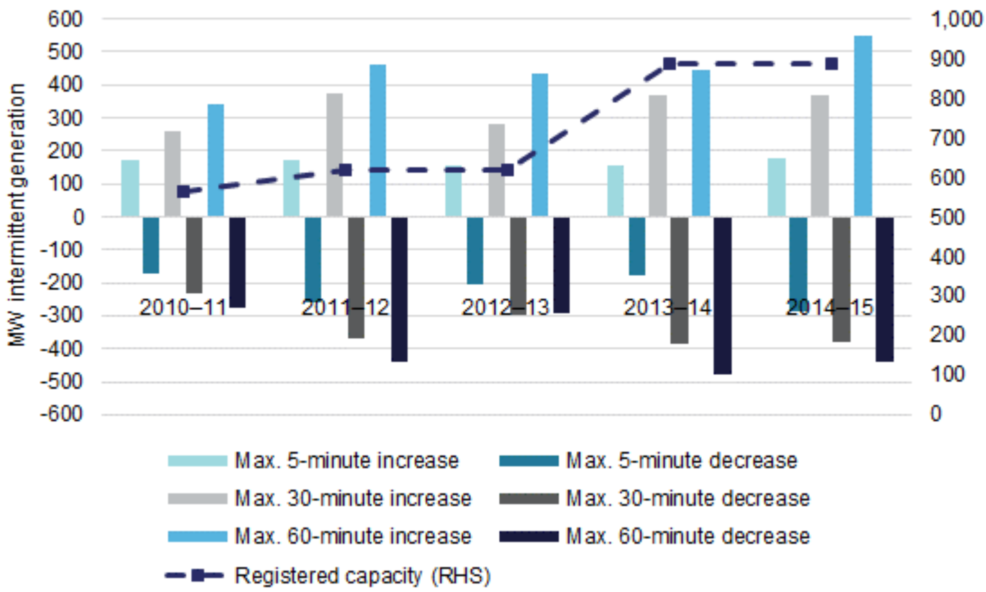
[6] Alternatively, some form of greater demand side management may be implemented. Such management also has an opportunity cost.

Figure 4-2. South Australian wind generation – Contribution to summer and winter peak demand



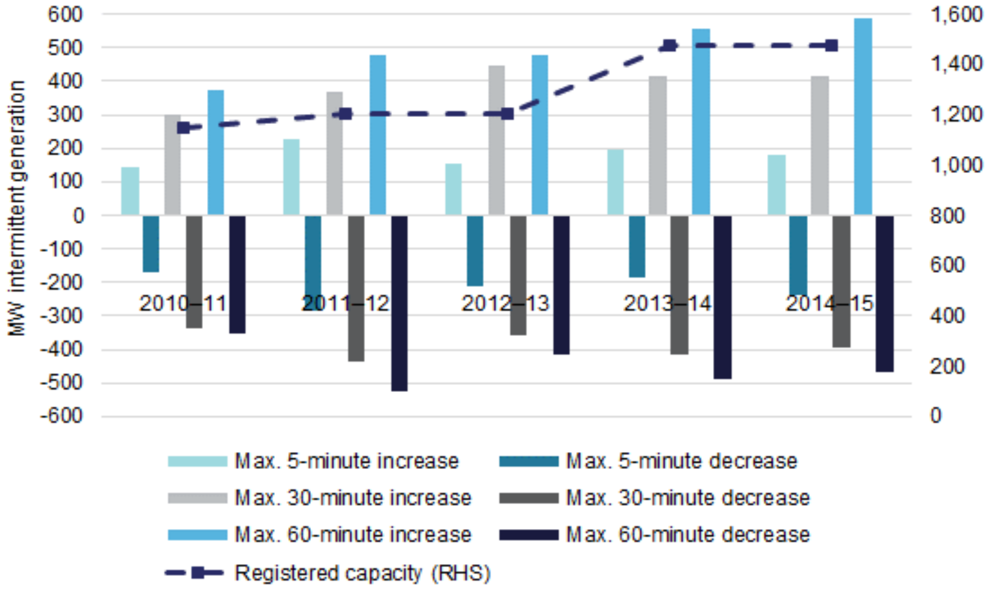
Source: AEMO 2015.

Figure 4-3. South Australian wind generation (Mid-north area) – Registered capacity and maximum output variation (MW)



Source: AEMO 2015.

Figure 4-4. South Australian wind generation (All) – Registered capacity and maximum output variation (MW)



Source: AEMO 2015.

4.2.2 Generation from solar PV installations

Solar PV installations also generate electricity intermittently. Solar PV panels do not produce electricity when the sun is not shining. As is the case for wind, the electrical output of solar PV can change nearly instantaneously and depends, inter alia, on the position of the sun in the sky, cloud cover, and the shadowing effects of obstacles (buildings, trees, etc.), which can vary over time scales as short as seconds (Wiser et al. 2011).

Unlike wind turbines, however, which are generally deployed as large-scale generation technologies, small scale solar PV installations are most often deployed on household rooftops. Their output is generally not 'visible' to the system operator, so that the system operator must then balance residual demand with supply. This aspect of solar PV technologies therefore introduces an additional element of operational difficulty in predicting consumers' (residual) demand, which then consists of an underlying variable demand profile overlaid with the variable output of rooftop PV installations. The accuracy with which output can be predicted to assist in the operation of a power system is also moderate, although spatial diversity can again smooth some of this variability.

5 Integration cost components of intermittent generation technologies

Following on from the particular characteristics of intermittent renewable technologies, the costs of integrating wind and solar PV into electric power systems can be decomposed into three approximately additive components:[7]

- balancing costs, which occur because the supply from IRGs is uncertain until realisation and forecasting errors therefore arise;
- profile costs, which are caused by the variability and particular intertemporal generation profile of IRG technologies; and
- grid costs, which arise from the specific location of IRG resources.

5.1 Balancing costs

Balancing costs arise because of deviations from planned generation schedules, and are essentially the result of forecasting errors. For IRG technologies such as wind and solar PV, forecasting errors come about because their output is uncertain until it is realised. For both types of technologies, the effects of forecasting errors are magnified at greater penetrations in a power system, because the forecast errors for multiple wind turbines or solar PV installations are generally positively correlated. Overall, higher penetrations of IRG technologies make it more difficult to predict and therefore balance supply and demand in a power system. Errors in forecasting the output of IRG technologies have two related consequences:

- they require adjustments to be made to the planned dispatch schedule of conventional power stations; and
- they require additional operating reserves to be held to respond to imbalances within very short timeframes of seconds to minutes.

Adjustments to planned dispatch schedules are costly because they represent a departure from the least-cost configuration of generators. In particular, baseload (and to a lesser extent) mid-merit power stations require time to begin operating and synchronise with the power system, and to make large changes in their level of output. System operators take into account these operational limitations as well as other constraints in the power system in assembling a dispatch schedule that meets expected demand at least-cost over a coming day or week. Forecasting errors that lead to adjustments in the planned dispatch schedule then introduce start-up, operating & maintenance (O&M) and fuel costs because more expensive conventional plant have to be

[7] The discussion in this section draws on Hirth et al. 2016, Hirth et al. 2015, and Ueckerdt et al. 2013.

dispatched than would have been the case under perfect foresight (Milligan and Kirby 2009). In South Australia, for instance, many high price events arise as a result of low wind output that had not been forecast, and that then require costly, rapid-response peaking plants to operate, while cheaper plants (which take more time to start, ramp up and synchronise) cannot be deployed.

System operators additionally address imbalances by deploying operating reserves that can rapidly respond to deviations between forecast and actual IRG output.[8] The need to hold additional reserves for balancing to account for greater forecasting errors also constitutes a cost to the power system. Output adjustments (ramping and cycling) increase wear and tear of thermal plants, while ramping constraints require generators to operate part-loaded to provide spinning reserve (so that cheaper generation cannot operate at full capacity).

5.1.1 International estimates of balancing costs

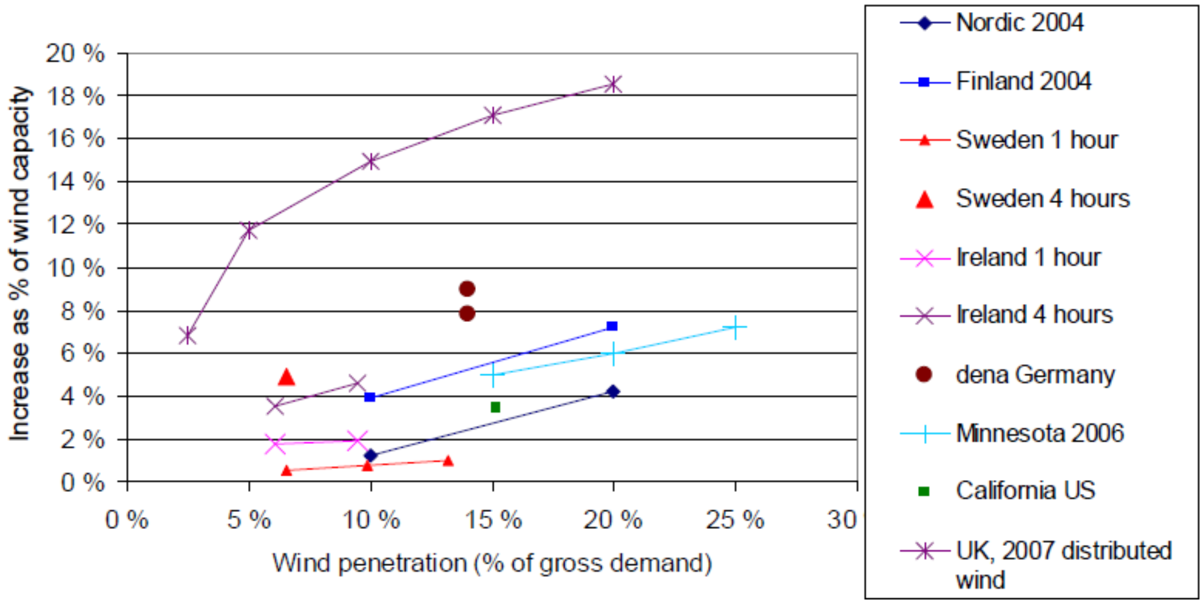
The challenges associated with balancing unexpected variations in the output of IRG technologies increase with the penetration of renewables in a power system, and are greatest within a one- to six-hour timeframe and in small systems. The increases in short-term reserve requirements estimated in recent studies then show a large range, corresponding to 1 to 15 per cent of installed wind power capacity at 10 per cent wind penetration and 4 to 18 per cent of installed wind power capacity at 20 per cent wind penetration (Figure 5-1, Holttinen et al. 2011). When wind forecast errors are combined with demand forecast errors, the reserve requirement is estimated at 15 per cent at 10 per cent penetration rates, and 18 per cent at 20 per cent penetration of gross demand.

Figure 5-2 shows the range of balancing cost estimates for thermal power systems from a recent survey undertaken by Hirth et al. (2015). Most studies summarised in Figure 5-2 focus solely on the balancing costs associated with wind generation; a handful include the effect of solar PV installations as well. Many studies that estimate the balancing costs of IRG technologies focus on one particular aspect of these costs; for instance, by considering only certain types of reserves and not changes to planned dispatch schedules (Gross et al. 2012). Nonetheless, the estimates shown in Figure 5-2 broadly reflect the consensus in the literature that the balancing costs of IRG technologies are relatively small compared to profile costs. Overall, most estimates of balancing costs are below € 6 per MWh (AU$ 9/MWh) of wind energy generated even at higher wind penetration rates. 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$ 0.09/MWh), so that balancing costs increase from €2/MWh (AU$ 3/MWh) to €4/MWh (AU$ 6/MWh)

[8] In AC power systems, system frequency is a fundamental indicator of power system health, and provides an immediate indication of the balance between generation and load (Kirby 2007). Frequency drops when load exceeds generation and rises when generation exceeds load. Large frequency deviations result in equipment damage and power system collapse. To control frequency, all power systems therefore maintain 'operating reserves' – generally supplied by conventional generators, but sometimes in the form of responsive load that can be curtailed very rapidly (Ela et al. 2011). Operating reserves can be called upon to provide additional output if demand rises rapidly or if there is an unplanned reduction in supply (upward reserve), or to reduce output if demand falls rapidly or there is an unplanned increase in supply (downward reserve). There are many classifications of operating reserves, many of which are system-specific.

as wind penetration increases from zero to 40 per cent.

Figure 5-1. Increase in reserve requirement as a function of wind penetration



Notes: The studies summarised above apply different timeframes to determine reserve requirements.

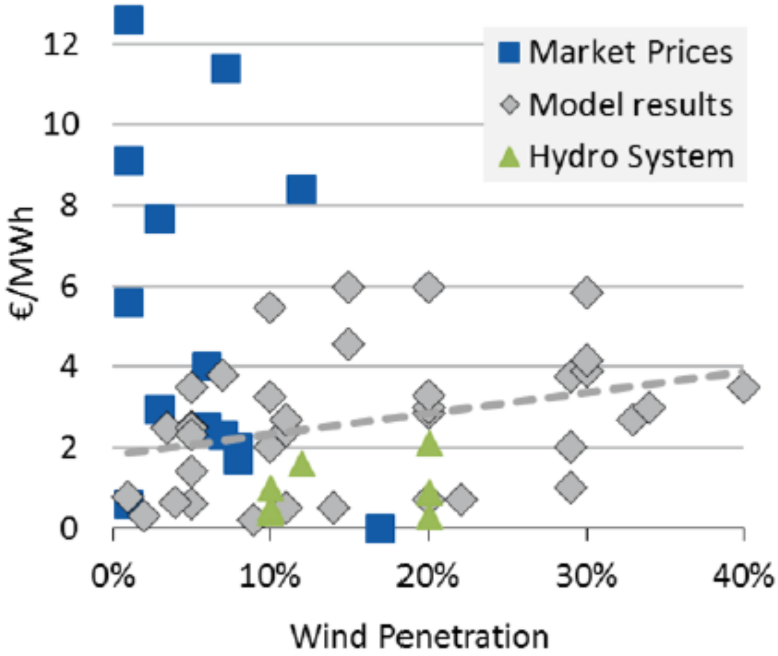
Source: Holttinen et al. 2011.

5.1.2 Australian estimates of balancing costs

In Australia, Riesz et al. (2011) estimated the additional balancing costs in the NEM and the 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. Regulation services are ‘load following’ services provided by conventional generators that continuously adjust their output to match variations in demand or the output of IRG resources. The corresponding WEM regulation service is called ‘Load Following’.

Riesz et al. (2011) found that in the NEM the Regulation requirement would increase by around 10 per cent of the added wind capacity. In the much smaller 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 outputs of wind farms in the SWIS are highly correlated, leading to larger ‘disturbances’ relative to the size of the system. While relatively small as a percentage of total system costs, the authors concluded that if the additional load following costs were allocated to wind generators, they would amount to AU$ 8.30 per MWh of wind energy generated in the NEM, and to $29.17/MWh of wind energy generated in the WEM.

Figure 5-2. Balancing cost estimates as a function of wind penetration



Notes: Squares denote balancing cost estimates derived from study based on wholesale market price outcomes, diamonds denote estimates derived from power system models, and crosses denote studies that incorporate both wind and solar power (crosses).

Source: Hirth et al. 2016.

5.2 Profile costs

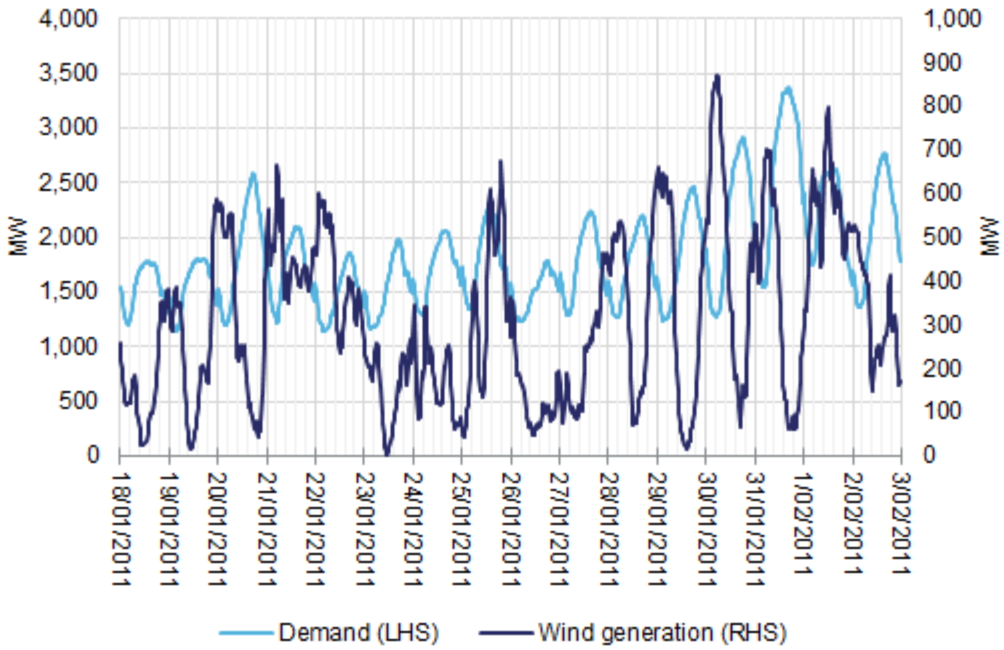
Profile costs arise indirectly from the temporal variation of the electricity output from intermittent generators. Profile costs reflect the empirical observation that the output of IRG technologies is often not well correlated with demand. This generation pattern tends to be quite pronounced for wind turbines, which tend to generate more when demand is low and there is ample available generation capacity, and which tend to generate less when demand is high and generation capacity is scarce. Figure 5-3 illustrates this effect in the South Australian region of the NEM during five high demand days in the summer of 2011. It shows that, over these five days, aggregate generation from wind capacity (drawn in dark blue) fell markedly as demand increased, and tended to be at its lowest when demand was at its highest.

Whereas balancing costs are a consequence of forecasting errors, profile costs occur even if the output of IRG resources could be predicted with certainty. In large part, profile costs arise because while IRG resources contribute some electricity, they hardly reduce the need for the overall capacity that needs to be maintained in a power system (Ueckerdt et al. 2013). Given that generating capacity is very costly, the profile costs of IRG technologies are therefore more material than balancing costs. As discussed in the following, profile costs can be decomposed further into:

- flexibility costs, which arise from specific operational requirements placed on dispatchable generators;
- utilisation or back-up costs, which arise because of the need to maintain significant conventional generation capacity; and

- overproduction costs, because at higher penetration, wind turbines may need to be constrained down or off because they produce more electricity than is demanded by consumers.

Figure 5-3. Wind generation and total South Australian demand from 20 January 2011 to 2 February 2011



Source: AEMO (2011).

5.2.1 Flexibility costs

Flexibility costs arise because the time-varying generation profiles of IRG resources require the output of conventional power stations to be adjusted more frequently, for instance, to compensate for the steep wind output gradients and peaks and troughs shown in Figure 5-3. Frequent ramping (up and down) or cycling whereby conventional power stations adjust their output in response to steep changes in the output of wind turbines or changes in demand (due to increased solar PV penetration) increases wear and tear on capital equipment, and reduces the efficiency of thermal generators.[9]

There are relatively few cost estimates of the flexibility effect (Hirth et al. 2015). Earlier studies report ranges from US$ 0.2 to US$ 2 (AU$ 0.3 to AU$ $2.5) per MWh of wind energy generated for the United States. The most recent study examined cycling costs (start-up fuel and variable O&M costs, and ramping costs) for the western US grid (including Canada and Mexico) for up to 33 per

[9] Flexibility costs refer only to planned ramping and cycling operations, while uncertainty-related ramping and cycling costs are reflected in balancing costs.

cent wind and solar energy penetrations (Lew et al. 2013). For thermal generators, cycling costs increase to around US$ 0.5 to US$ 1.2 (AU$ 0.6 to AU$ $1.5) per MWh with increasing penetration of wind and solar PV.

5.2.2 Utilisation costs

Utilisation or capacity costs arise because the production profile of IRG resources generally does not match the demand profile of consumers well. The deployment of IRG technologies in a power system reduces the amount of electricity generated by dispatchable power stations. Wind turbines (which incur no fuel costs) are always 'dispatched' before conventional generators, and tend to displace mid-merit plant at lower penetration rates and baseload plant when penetration increases. In contrast, solar PV installations reduce 'residual' electricity demand.

Individually and in combination, these trends reduce the utilisation (or capacity factor) of conventional dispatchable power stations. The annual and life-cycle generation per unit of capacity of these plants is reduced, and the average generation costs per MWh in the residual system increases. The key point is that while the utilisation of conventional power stations declines, the capacity (or capability to generate) of these plants remains essential to the secure operation of the power system. The need to carry additional conventional generation capacity (or some type of storage technology) to compensate for the intermittency of IRG resources then represents a significant cost to the power system.

The empirical observation that, in particular, significant quantities of wind capacity hardly reduce the amount of (back-up) capacity that needs to be maintained in a power system is also apparent in Figure 5-4, which shows that very little wind generation was available to meet peak demand during the 2011 heatwave in South Australia. More generally, low wind generation at times of high demand is a relatively common occurrence in South Australia, in other NEM regions, and in overseas jurisdictions where significant amounts of wind capacity have been installed. Table 5.1 shows the share of installed wind generation capacity that was historically available at least 85 per cent of the time during the top 10 per cent of demand periods across the NEM regions. For example, the historic performance of total wind generation in South Australia during the top 10 per cent of summer demand periods is such that wind generation contributed less than 10 per cent of installed wind capacity to meeting peak demand 85 per cent of the time, and less in other regions of the NEM. The implication is that while South Australia has the highest penetration of wind generation in the NEM with an installed capacity of around 1,475 MW, wind generation generally meets less than 10 per cent of demand when consumers require it most.

Table 5-1. 85 percentile wind contribution to operational maximum demand factors

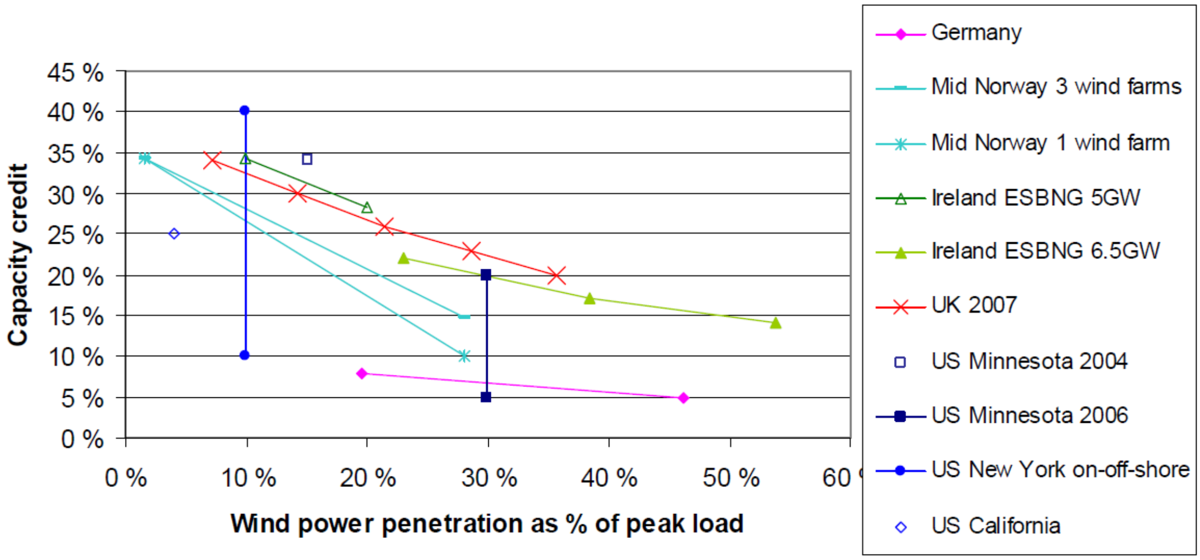
	New South Wales	Victoria	South Australia	Tasmania
Summer average contribution	1.2%	7.0%	9.9%	7.8%
Winter average contribution	3.4%	6.7%	6.9%	3.6%

Source: AEMO 2015. NEM Historical Market Information Report.

Table 4-1 is an example of the low 'capacity credit' that is generally assigned to IRG technologies.

Although there are differences across power systems, generation adequacy evaluations are generally used to assess the capability of generation resources to reliably meet electricity demand (Wiser et al. 2011). 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. 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 generally positively correlated. For instance, Figure 5-4 shows that for the large UK system, the capacity credit of wind turbines declines from around 34 per cent at less than 10 per cent penetration to around 20 per cent at a penetration of 35 per cent. In the small Irish power system, the capacity credit declines to 15 per cent at higher penetrations.

Figure 5-4. Capacity credit of wind power



Notes: The estimates shown above depend on how generation adequacy is assessed, the correlation of wind power output to electricity demand, the geographic distribution of wind turbines, and the level of wind electricity penetration.

Source: Holttinen et al. 2011.

The low average capacity credit of wind turbines (compared to dispatchable generators) means that systems with large amounts of wind energy will need to hold significantly more generation capacity in reserve to meet the same peak electricity demand than will 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 consumers.

Where solar PV installations are concerned, the general finding in the literature is also that the economic value of PV systems is reduced at increasing levels of system penetration due to the high variability of PV, although geographical diversity can smooth out some of these effects (Arvizu et al. 2011). The capacity credit of these installations is highly dependent on the extent to which solar PV generation is correlated with demand. In the mainland regions of the NEM, rooftop PV installations have historically not reduced summer peak demand, which typically occurs in the late afternoon when rooftop PV generation is declining from its midday peak (AEMO 2012). AEMO

(2016) projects that solar PV installations will moderate summer peak demand (but not winter peaks), so that there may be some (small) reduction in the amount of seasonal thermal back-up capacity needed.

5.2.3 Overproduction

Overproduction costs arise at high levels of IRG penetration. When large amounts of intermittent wind and solar PV capacity are installed, the incidents when these technologies produce more electricity than is demanded by consumers rises, and the output of these technologies either has to be curtailed or 'spilled'. Hence, the effective capacity factor of renewable generation decreases and specific $ per MWh costs increase.

The frequency and magnitude of negative spot price outcomes that are often observed in electricity wholesale markets with significant wind penetration can be interpreted as an indication of overproduction (Baldick 2012). Unlike conventional generators who are not dispatched and not paid when their output is not required, the subsidy arrangements around wind turbines are often such that these plants earn revenues whenever they generate electricity (irrespective of system requirements or spot prices). Negative price outcomes that arise because wind turbines receive additional LGC payments in addition to the revenues earned from NEM operations have mostly occurred in South Australia. In that NEM region, negative prices were posted for 154 (half-hourly) trading intervals in 2014-15, mostly during periods of high wind generation combined with low demand and limits on interconnector flows restricting exports from South Australia to Victoria (AEMO 2015).

5.2.4 Aggregate profile costs

Figure 5-5 summarises aggregate wind profile cost estimates from some 30 publications, as reported in Hirth et al. (2015).[10] If it is assumed that changes are made to the capacity mix by retiring existing plant and investing in more flexible generation capacity (the blue line), wind profile costs are estimated to be zero or slightly negative at low penetration rates, and to be around €15 to €25 (AU$ 22.50 to $37.5) per MWh at penetration rates in the 30 to 40 per cent range. A fitted trend line indicates that even in such a long-term investment scenario, the profile cost of wind power increase by €0.5 (AU$ 0.75) 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, as shown by the gradient of the grey line.

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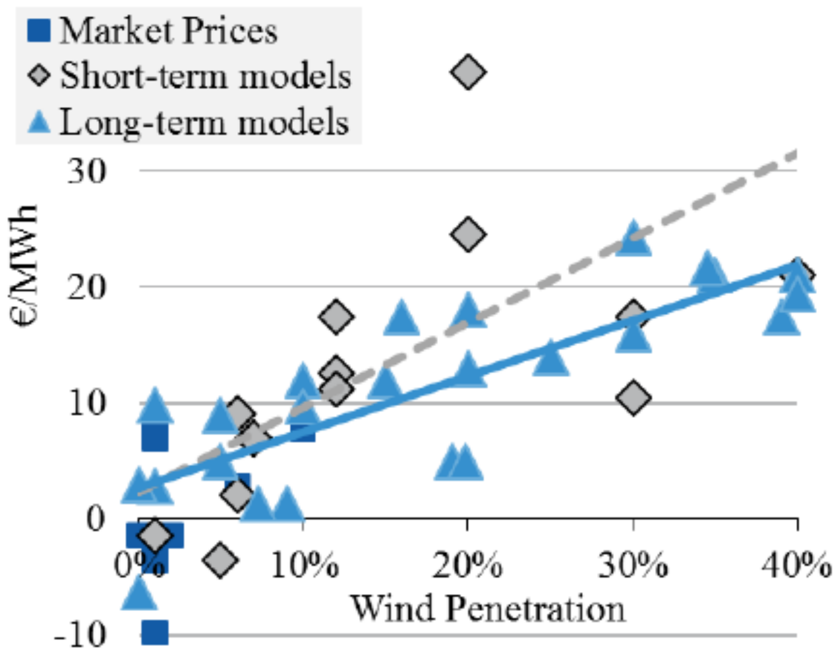
[10] Many of the studies cited only report estimates of the utilisation effect. As such these estimates are likely to underestimate total profile costs.

Figure 5-5. Profile cost estimates as a function of wind penetration



Notes: Squares denote profile cost estimates derived from study of wholesale market price outcomes, diamonds denote estimates derived from power system models, and triangles denote studies of long-term dispatch and investment outcomes.

Source: Hirth et al. 2016.

5.3 Grid-related costs

The grid-related costs of IRG technologies arise because their supply is often location-specific, in the sense that the primary 'energy carrier' (wind or sun) cannot be transported in the same way as fossil or nuclear fuels (Hirth et al. 2015). Integration costs then occur because electricity transmission infrastructure is costly. Two aspects of grid-related costs are cited in the integration cost literature:

- costs that arise if additional network investment is necessary to accommodate IRG resources, for instance if high quality IRG sites are located far from demand centres; and
- additional transmission losses and congestion costs, for instance, if the additional output from renewable generators constrains existing transmission infrastructure.

The majority of estimates of grid-related costs for IRG technologies come from wind integration studies (Weiser et al. 2011). The integration of additional wind resources into an existing power system commonly requires additional grid infrastructure both within a particular region and to interconnect with neighbouring regions. At the same time, grid reinforcement and congestion costs depend on where wind turbines are located relative to load and grid infrastructure, and therefore vary by type of system, grid infrastructure and country. It is also the case that large-scale transmission investments can have broader system benefits, so that estimating grid-related costs requires decisions to be made about the share of costs that should be allocated to IRG resources.

The impact of increasing rooftop PV deployment on grid-related costs is less clear. AEMO (2015d) reports that more rooftop PV typically reduces transmission congestion, as it reduces operational demand, but note that very high levels of rooftop PV in a particular location may cause congestion in the distribution network. Overseas studies also note that a high penetration of rooftop PV installations can present significant challenges to operating distribution networks (McDonald et al. 2013, EPRI 2005). A certain amount of distributed generation can generally be accommodated without making changes to protective devices or operating procedures. However, beyond a certain point, negative effects appear that relate to difficulties in regulating local voltages, other issues with power quality which may interfere with the operation of equipment and shorten equipment life, and raised fault levels.

5.3.1 International estimates of grid-related costs

Given the many factors that play a role in determining grid-related costs, the range of estimates in the overseas literature is large:

- Mills et al. (2009) reviewed 40 detailed transmission studies undertaken in the United States between 2001 and 2008 that estimated the cost of integrating wind power. The median cost grid cost was found to be US$ 15/MWh (AU$ 18.8/MWh).
- More recent European studies suggest that grid reinforcement costs are about €3.75 /MWh (AU$ 5.6/MWh) at wind shares of 15 to 20 per cent, and about €7.5/MWh (AU$ 11.3/MWh) at 40 per cent wind penetration (Ueckerdt et al. 2013).

Overall, Ueckerdt et al. (2013) estimate that the increase in grid costs with increasing shares of IRG up to 7.5 €/MWh on average (AU$ 11.3/MWh) or about 13 €/MWh in (AU$ 19.5/MWh) in marginal terms.

5.3.2 Outcomes in Australia

In Australia, augmentation of the Heywood Interconnector between Victoria and South Australia at a cost of around $108 million was, to a significant extent, driven by increased IRG penetration in South Australia. The rapid and substantial deployment of wind and rooftop PV generation in that NEM region has resulted in the withdrawal of more than 1,500 MW of coal- and gas-fired generation capacity, so that South Australia is reliant on inter-regional imports to meet demand at critical times (AEMO 2015a). The increase in interconnector transfer capacity from 460 MW to 650 MW was then justified on the basis of reliability benefits that would accrue to South Australian consumers, the ability to export surplus renewable generation to other NEM region and, relatedly, reduced transmission network congestion.

AEMO's 2013 assessment of a '100 Per Cent Renewables' study provides an indication of the scale of transmission investment that would be required to accommodate a high share of renewables in the NEM. AEMO (2013) noted that many renewable resources are in locations that are remote from the current transmission system, and identified a number of high-level transmission options that would need to be developed. AEMO's cost estimates for an 'optimised' (100 per cent renewables) electricity system that would minimise combined generation and transmission costs then range from $27 to $30 billion in 2030, and $34 to $39 billion in 2050.

5.4 Broader system challenges

The integration costs discussed above relate to impacts on power systems that are relatively well-understood, in the sense that they can be quantified on the basis of how systems are currently operated. However, the combination of a rising share of IRG technologies and the withdrawal of conventional (steam turbine) power stations that is apparent in the NEM creates new challenges to power system operations. Broader questions then arise about the types of ancillary services that will be required in the future, and how they should be provided and paid for.

Conventional generators – particularly large coal-fired plants – have certain inherent characteristics that contribute to the stability of the grid, but are currently not explicitly priced in the NEM. When such generators operate they provide 'inertia'; that is, they are synchronised to the frequency of the grid, and thus contribute to the ability of the power system to 'ride through' fault events and limit system frequency excursions.[11] As conventional generators are displaced by non-synchronous (wind and solar) generation technologies,[12] the overall reduction in inertia tends to increase the frequency and magnitude of power system disturbances, so that the power system becomes more vulnerable to fault events.

The 2015 NTNDP accordingly identifies a number of other emerging challenges that are directly related to the increasing penetration of IRG resources and the withdrawal of thermal power stations (AEMO 2015e). The reduced availability of dispatchable generation will make it increasingly difficult to forecast demand, supply and the behaviour of the power system; balance demand and supply in real time; and control network flows to remain within secure limits. In addition, and as more thermal synchronous generators withdraw from the NEM, there may be insufficient inertia and network support services available to be shared across all regions, and a loss of voltage support and larger voltage fluctuations during network faults.

A number of these challenges are already apparent in South Australia, and are expected to arise in the remainder of the NEM and the Western Australian WEM at higher levels of IRG penetration. In South Australia these challenges relate to AEMO's ability to balance the system either during or following the loss of the Heywood Interconnector, which makes the power system more susceptible to frequency deviations and limits AEMO's ability to acquire FCAS services (AEMO and ElectraNet 2016). In these circumstances South Australia would become 'islanded', and the risk of load shedding in South Australia, as occurred in November 2015, would increase.[13]

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[11] Power system inertia is a measure of the energy stored in the rotating masses of generators synchronised to the power system (as measured in units of megawatt seconds, MW.s). The amount of inertia a given generator provides is a constant value, and depends on the generator's design and size. Larger/more massively built generation units contribute more inertia.

[12] Some wind turbine designs can provide inertia to the system. However, in the NEM the contribution to inertia of wind turbines is small and is ignored in real-time operations.

[13] The load shedding event on 1 November 2015 occurred when one Heywood Interconnector line tripped while the second line was out of service. The South Australian power system was islanded and 160 MW of demand remained unserved for more than 1.5 hours.

5.5 Aggregate integration costs

The components that constitute the integration costs of IRG resources – balancing, profile and grid costs - are not constant parameters, but are functions of many system properties (Hirth et al. 2016). A review of the literature nevertheless reveals a number of important trends that apply across predominantly thermal power systems. The most important of these is that integration costs increase with the penetration of IRG resources:

- At low levels of penetration, the integration costs of intermittent renewables may be low or even negative. In these circumstances, the additional balancing and profile costs are outweighed by the fuel cost savings from wind and solar PV resources. Overall, integration costs are considered to be relatively small at penetration levels of up to 10 per cent.
- Even allowing for adaptation in the generation mix to account for the uncertainty and variability of intermittent renewables, the integration costs of IRG technologies can become very high at high penetration rates. When wind penetration reaches 30 to 40 per cent, balancing costs are estimated to be AU$ 6 per MWh of renewable energy generated, while profile costs are in the range of AU$ 30 per MWh of renewable energy generated. Profile costs – which arise from the need to maintain additional costly generation capacity in the system to manage the significant output variability of intermittent resources – are significantly higher than balancing costs.

Overall, and allowing for long-term changes in the generation mix, 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.

6 Minimising the total costs of a power system

A power system operates as an interdependent portfolio of power stations that are deployed jointly to meet consumer demand. A long-term economic assessment of the optimal generation mix (including the share of renewables) that minimises the cost of supplying consumers with electricity cannot therefore consider only the stand-alone LCOE of a technology, but must also take into account the increase in total system costs as a result of integration costs. If these interdependencies are accounted for, a formal evaluation of the optimal generation mix leads to two optimality conditions that offer important insights about the deployment of IRG technologies (Hirth et al. 2016):

- any welfare or competitiveness analysis of IRG technologies must account for the effect of intermittency on the value of these technologies in a power system; and
- the effect of intermittency is that IRG technologies produce the least-value electricity, and that value is increasingly reduced at higher shares within a power system.

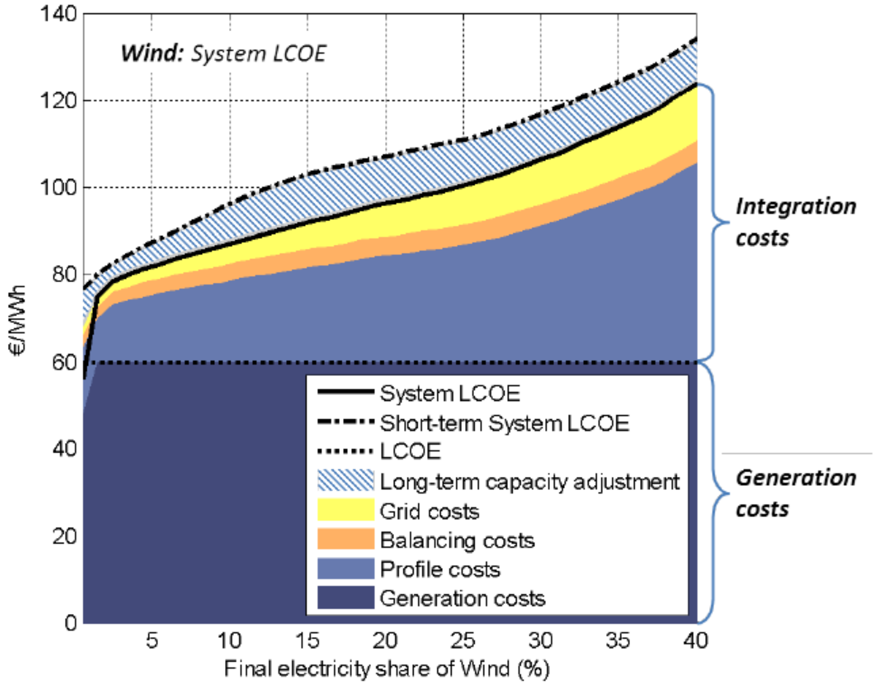
6.1 System versus stand-alone costs of intermittent renewables

The balancing, profile and grid-related costs that are incurred when intermittent generation technologies such as wind or solar PV are integrated into a power system cause costs in the residual power system to increase with rising shares of these technologies. In effect, the stand-alone LCOE of an IRG technology understates the full economic cost of that technology. That economic cost is instead captured by the ‘system’ LCOE of a technology, which comprises its stand-alone LCOE and integration costs at a system level.

Figure 6-1 shows the system LCOE of wind as a function of increasing wind penetration for a typical European thermal power system. At a low market share, integration costs are slightly negative (since wind generation reduces fuel cost), but integration costs increase steeply with further deployment. At moderate shares the system LCOE cost curve is concave; at shares above 25 per cent it becomes convex. The short-term system LCOE of wind is larger than the long-term LCOE, since the latter assumes that the generation mix in the residual power system is adjusted to accommodate wind generation.

The implications of rising integration costs of IRG resources is that these costs may potentially outweigh any cost reductions that IRG resources may achieve in future. That is, irrespective of the stand-alone LCOE of IRG technologies, the system LCOE of these technologies is such that the total cost of the power system increases disproportionately with their deployment. There are therefore material economic barriers to large-scale deployment of IRG technologies.

Figure 6-1. Marginal system LCOE of wind generation



Notes: The LCOE of wind is assumed to be €60/MWh (AU$ 90/MWh).

Source: Ueckerdt et al. 2013.

6.2 Value versus stand-alone cost of intermittent renewables

In a power system with an optimal generation mix, the marginal *stand-alone LCOE* of a specific generation technology (excluding subsidies) equals its marginal value to consumers. In a market context, the marginal value of a generation technology is consumers' average willingness to pay for that technology's output: the weighted-average spot price which it earns from selling its output over a given timeframe, say a year (Hirth et al. 2016). For a given coal-fired power station, for example, the marginal value of that plant is the weighted-average $ per MWh spot price it earns in each trading interval over a year when it generates electricity, p_{coal}. For a given wind turbine, the marginal value of that turbine is the annual weighted-average $ per MWh spot price it earns when it generates electricity, p_{wind}.

The first implication of this general result is that the optimality condition is distinct for each generation technology. Differing generating technologies operate to meet demand at different times and therefore have different temporal production patterns. Given that the price of electricity varies a great deal over time, ranging from lowest at off-peak times to highest at peak times, the marginal value of different generation technologies also does not coincide. The optimal deployment for each generation technology therefore also varies, depending on its value in the power system. Government policies that set a targeted level of IRG output as part of a renewable energy mandate without considering the value of the electricity produced by that technology are therefore almost certainly inefficient, and will increase costs to consumers at higher levels of IRG technology penetration.

Second, unlike what is commonly claimed by proponents of renewable energy mandates, it is not the case that IRG technologies will invariably become 'competitive' as the LCOE of these technologies continues to fall. LCOE comparisons between IRG and other generation technologies are misleading because they fail to consider the value of IRG resources within a power system (IEA 2016). From a social welfare or competitiveness perspective, it is irrelevant whether or not the LCOE of wind or solar technologies is below or above that of other generation technologies; what matters instead is a given technology's cost relative to its value. Thus, the electricity that can be supplied by a wind generator at a low levelised cost is not 'cheap', if the output is mostly available at night when demand is low, supply is plentiful, and the value of electricity is also low. Conversely, the electricity that can be supplied by a gas turbine at a very high levelised cost is not 'expensive', if it can be called upon to generate during peak demand periods when the system is stretched to capacity and the value of electricity is very high. Simplistic levelised cost comparisons between different generation technologies are then meaningless because they implicitly assume that the electricity generated from different sources has the same value in the power system.

6.3 Value versus price of intermittent renewables

One of the key findings in the integration literature is that the intermittent properties of IRG technologies reduce their market value (the weighted-average price they earn) as their market share in a power system increases (Hirth et al. 2015). In efficient wholesale power markets, the relatively low value of IRG technologies, as measured by the weighted-average spot price reflects the opportunity cost of intermittency or integration costs.[14]

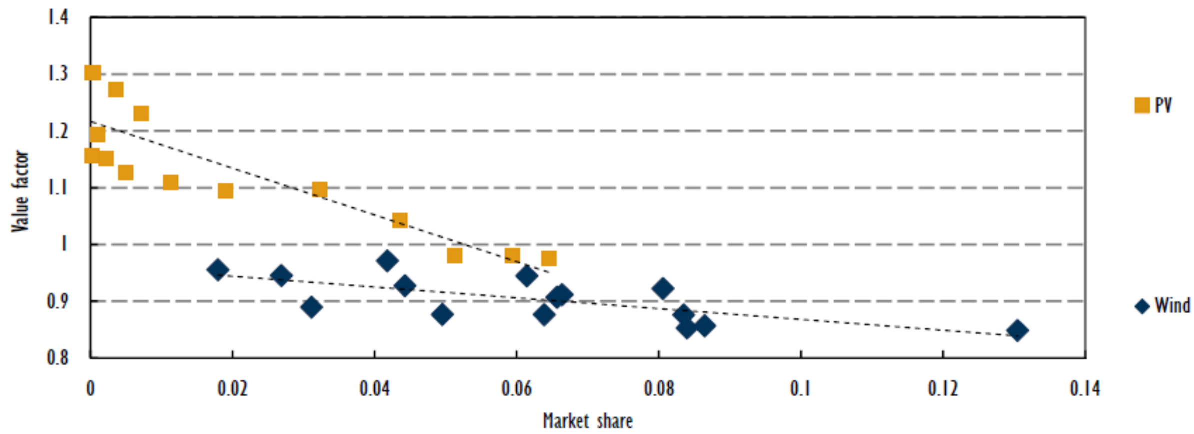
The duality between prices and costs implies that the integration costs of IRG technologies can be inferred from the relatively lower prices these technologies earn in wholesale markets (Hirth et al. 2016, IEA 2016). The difference between the weighted-average wholesale market price for a power system over a year p_{System} and the technology-specific weighted-average spot price, say p_{wind}, is interpreted as a 'value gap' between the value of electricity that consumers demand and the value of electricity that a particular technology supplies.

Figure 6-2 illustrates this concept for a case study of wind and solar integration in the German power system. The 'value factor' is the ratio between the weighted-average system price p_{System} and the weighted-average price for a specific technology p_{wind} so that a value factor of less than unity indicates a value gap. Figure 6-2 shows how a rising share of wind and solar capacity progressively reduces the value factor of these technologies, consistent with the finding that the integration costs of IRG technologies rise with increasing penetration. At the onset of deployment, solar PV installations generate at times of fairly high demand (when wholesale electricity prices are high) so that the value factor is above unity for a penetration of around 4 per cent. At greater penetrations of solar PV, the value factor drops rapidly below one, because solar power is concentrated in a few hours of the day. In contrast, the value factor of wind generation is never

[14] The finding that integration costs are reflected in weighted-average wholesale prices requires wholesale markets to be 'perfect' and 'complete' in an economic sense. These are strong assumptions. For instance, electricity wholesale markets may not price all costs (such as locational price differences arising from congestion), as is the case in the NEM and the WEM. The exercise of generator market power may also mean that prices are not efficient in some trading intervals.

greater than unity, and declines to a level of around 0.85 at a penetration of around 13 per cent. More generally, virtually all studies that quantify the market value of solar power find value factors above unity at penetrations of 2 to 5 per cent, but value factors of 0.7 to 0.9 at 10 per cent penetration and around 0.4 to 0.7 at 30 per cent penetration (Hirth 2015). Even accounting for the long-term adaptation of the thermal capacity mix, the value of solar PV generation drops by 3.3 to 3.5 per cent, per percentage point increase in market share.

Figure 6-2. Market value factor of wind and solar PV as a function of their market share in Germany (2001-15)



Notes: Each point corresponds to one year; the value factor is defined as the ratio between the electricity market revenue of the average wind/solar generator and the average electricity price.

Source: IEA 2016.

The observation that the value factor of IRG technologies strictly declines as their share in a power system increases is referred to as the 'self-cannibalisation effect'. It arises because renewable technologies tend to produce disproportionately during times when the electricity price is low, and because their output is correlated. As more capacity is added to the system, IRG technologies will tend to generate at similar times, so that there is increasingly an abundance of electricity at these times, which in turn leads to lower prices, a lower system value, and a lower value factor.

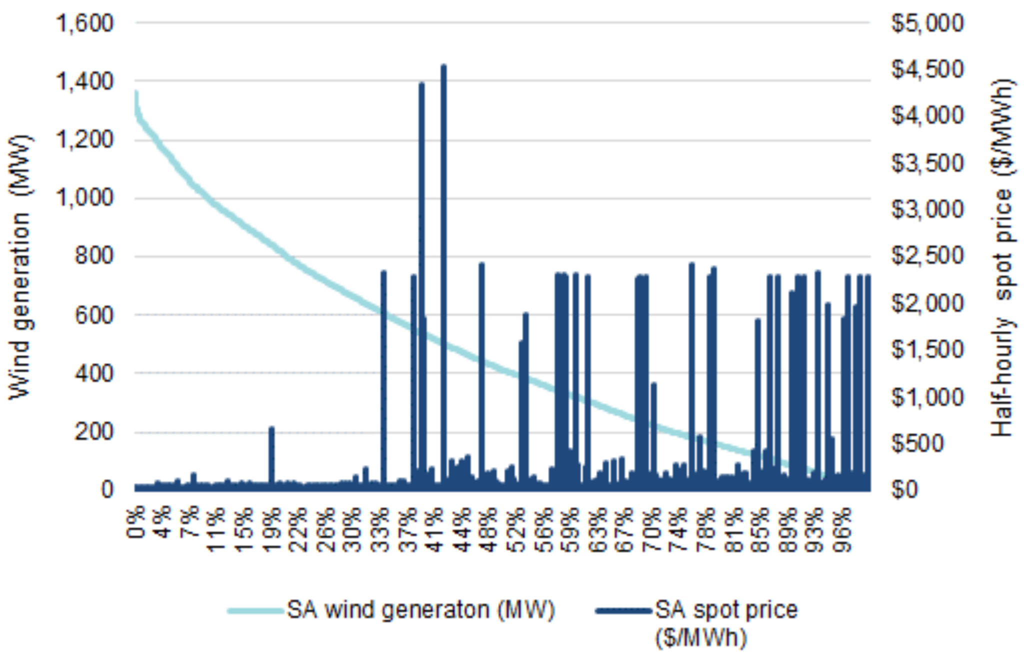
The exact magnitude of the value decline of IRG resources is system-specific. However, the studies that have been undertaken commonly find that in predominantly thermal power systems, at high penetration rates (such as 20+ per cent for wind or 10+ per cent for solar, intermittent technologies produce the least-value electricity (Hirth et al. 2016). At such penetrations, integration costs play an increasing and material role. Thus intermittency increasingly reduces the market value of renewable generation such that, on average, one MWh from wind power is worth increasingly less than one MWh from a conventional power station. The implication is that the greater the share of renewables in a power system, the lower its value, and the higher the subsidies required to support it.

7 Intermittent generation and price volatility

One of the effects of increasing the share of IRG technologies in a power system, notably the share of wind, is an increase in the volatility of wholesale prices. Fundamentally, greater price volatility is a reflection of the significant variation in the output that wind turbines are able to generate at any point in time and the positive correlation of output from wind turbines, as well as the potentially rapid rate of change in wind output. For instance, when the wind is blowing, multiple wind turbines will generate electricity, and greater output from wind generators will depress wholesale prices as low as zero or even result in negative prices. Conversely, when the wind is not blowing across a wide area, few or no wind turbines will generate electricity, so that wholesale prices are disproportionately determined by conventional generators. Furthermore, and as an increasing share of conventional generation is withdrawn from the system with a greater penetration of renewables, fewer conventional generators are available to operate when wind generation is low. Wholesale prices during conditions when wind generation is low are therefore elevated.

In South Australia, for instance, the high reliance on wind generation has led to the closure of Northern and Playford B power stations, corresponding to 786 MW (or 15 per cent) of generation capacity. This situation has led to a recurring pattern of price spikes in circumstances where wind output was very low (often in combination with limits on interconnector flows) and where the remaining conventional power stations could command very high prices for their output. Figure 7-1 accordingly illustrates that the incidence of price spikes predominantly occurs when wind generation is low.

Figure 7-1. Wind output and high price events – South Australia (2014-15)



Source: AEMO 2015.

The volatility of South Australian wholesale prices has implications for electricity derivative markets and the ability of market participants to hedge against price risks (Deloitte Access Economics 2015). Derivatives such as base swaps or caps enable retailers and large users to either fix or cap the price they pay for a given volume of electricity, and are typically sold by baseload and mid-merit plant. As these types of generators exit the market as a result of the increasing penetration of renewables, the supply of derivatives is also reduced so that it becomes increasingly difficult to manage price risks.

8 Integrating an increasing share of renewable generation into Australia's electricity markets

There are a number of studies that suggest that high shares of renewable generation are technically feasible in the Australian electricity market. For example, the study by AEMO (2013) mentioned earlier suggests that a 100 per cent renewable share is technically feasible at costs that are high but 'appear manageable'. Similar conclusions have been reached by Elliston, MacGill and Diesendorf (2013) and Wright and Hearps (2010). However, few such studies consider the market context in which electricity markets operate and whether, given current market structures, financing models exist that will allow the necessary investment in increasing renewable capacity, network infrastructure, and also in the energy storage necessary to ensure that system reliability is maintained.[15]

The electricity market reforms that led to the establishment of the NEM in the 1990s were aimed at improving pricing efficiency and capital allocation. The NEM is an energy only market where generators are expected to be ready to dispatch electricity when requested to ensure that the power system remains reliable but are paid only for the energy they produce. With increasing shares of renewable generation with zero fuel costs and therefore close to zero short run marginal costs, dispatchable generators must rely on periods of high electricity prices, increasingly caused by the lack of correlation between peak demand and the times that renewable generators are able to supply electricity. In South Australia for example, it is estimated that only around 10 per cent of wind capacity and 31 per cent of solar capacity can be relied on during times of peak summer demand (AER 2015, pp.30-1). The extent to which price volatility can be relied on to justify new investment in an energy only market will depend, among other factors, on the price cap (currently $14,000/MWh in the NEM) and the ability of investors to write long term forward contracts with electricity retailers for purchase.

High price volatility is likely to be a challenge for both consumers and governments. Riesz, Gilmore and MacGill (2016, p.122) estimate that a market price cap of $60,000 to $80,000/MWh would be required to recover average system costs and to compensate for median prices close to zero in the case of a 100 per cent renewables scenario in the NEM. While this scenario has no practical importance today it does illustrate the potential challenges being faced in re-designing the NEM to cope with increasing shares of renewables.

At a practical level, the recent South Australian experience with lack of security of electricity supply illustrates the challenges that will need to be faced as the share of renewables rises. Currently in South Australia wind provides about 33 per cent of electricity load, and about 25 per cent of households have installed solar PV generation, while total grid based electricity demand has fallen since 2011. In these circumstances, a number of conventional generators are no longer

[15] For a recent review of energy storage technologies see USDOE 2015.

commercially viable and have withdrawn from the market. Nelson and Orton (2016) set out in detail the recent experience in the South Australian electricity market and conclude that a 'root-and-branch review of energy market design and governance is required – to consider how best to decarbonize Australia's electricity supply across the generation, transmission, distribution, and retail components of the supply chain while maintaining supply security, efficient pricing, and appropriate risk allocation.' Such a review seems essential if Australia's political parties continue to support further increasing the RET, and given that substantial new investment in the power system overall will be required to achieve such a target.

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