Relevant level method review 2018 Capacity valuation for intermittent generators

Draft report

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Economic Regulation Authority
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DMS196852

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Monday, 18 February 2018.

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

You can also send comments through:

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Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at records@erawa.com.au.

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Executive summary

The South West Interconnected System is a small, geographically isolated electricity system. To provide a reliable supply of electricity for consumers, the Wholesale Electricity Market (WEM) was designed to have sufficient local electricity generation available to satisfy demand at all times, and to deal with supply emergencies.

Each year, the Australian Energy Market Operator (AEMO) procures enough generation capacity to deliver a reliable electricity supply by assigning capacity credits to generators and demand-side management providers, such as large industrial power users. Electricity retailers fund the purchase of these capacity credits. The amount retailers pay depends on their contribution to peak demand in the WEM: a ‘user pays’ approach. The higher a retailer’s demand during peak times, the more capacity credits it must fund.

The cost of having generation capacity available must be balanced against the benefit to consumers of having a reliable electricity supply as ultimately, consumers pay. Retailers pass the cost of capacity credits on to electricity consumers through retail tariffs. If more generation capacity is procured than is required, the South West Interconnected System (SWIS) will be more reliable but customers will pay for generation capacity they do not need.

Generators and demand-side management providers in the SWIS are assigned capacity credits based on their contribution to the reliability of the system. Therefore, each megawatt of capacity provided must be equivalent. Intermittent generators such as wind and solar farms by their nature have variable, weather-dependent output. This variability must be taken into account when determining to what extent intermittent generators can be relied upon to have capacity available when needed to meet demand and support reliability in the SWIS. The method AEMO uses to determine the quantity of capacity credits allocated to intermittent generators is called the relevant level method.

As the number of intermittent generators in the SWIS continues to grow, the relevant level method becomes increasingly important to ensure intermittent generators are awarded capacity credits that reflect their contribution to reliability, as shown in the box below.

Over the capacity years 2016/17 to 2019/20, intermittent generators’ share of the total quantity of capacity credits assigned to facilities in the SWIS doubled to 3.8 per cent.

For the 2019/20 capacity year:

- 21 intermittent generators received approximately 183 MW of capacity credits in total, equivalent to around 24.5 per cent of their installed capacity.
- Based on a price of $126,638 per capacity credit, the value of capacity credits allocated to intermittent generators is approximately $23 million.

Every three years, the ERA reviews the relevant level method and examines if it meets the objectives of the WEM. These objectives include lowering long-term costs for electricity consumers, promoting the reliable supply of electricity, and avoiding discrimination against energy technologies, including renewable resources. This draft report outlines the ERA’s review of the current relevant level method and explains why the ERA recommends the method should be changed.

Calculating the value of capacity

The most stringent reliability target in the SWIS specifies the system should have sufficient capacity to meet a level of peak demand that is likely to happen just once every 10 years. The sum of the available capacity of generators and demand-side management providers must be sufficient to cover this one in 10 year peak demand with the desired level of reliability.

Both the available capacity of resources and demand are variable. Output from intermittent generation technologies is variable as wind and solar farms can only produce energy when the wind is blowing or the sun is shining. Demand is also variable and tends to increase as the air temperature rises. The output of coal or gas-fired conventional generators can vary too. For instance, conventional generators may not be able to produce energy at their maximum capacity due to mechanical failures, and their available capacity can decrease when air temperature is high. Therefore, at any point in time, many different combinations of demand and available capacity can occur.

The relevant level method needs to calculate the capacity contribution of an intermittent generator to reliability in the SWIS based on numerous combinations of the available capacity of generators and demand, all forecast two years ahead.

Detailed calculation methods are usually needed to estimate an intermittent generator's capacity value given the volume of data to manage, and the many different supply-demand combinations that could eventuate. Simplified techniques have also been developed to emulate the outcomes of detailed calculation methods. However, these techniques are usually subject to some conditions or assumptions, and reasonable capacity valuations are only possible if the conditions are met.

One such technique is the development of a simple formula to approximate the capacity contribution of intermittent generators, but only when their installed capacity in the system is very low. The formula uses an adjustment to intermittent generators' output during a sample of periods when the electricity system faces capacity shortages. The current relevant level method is based on an adaptation of this simple formula.

Findings from the ERA's review of the current relevant level method

The current method contains several shortcomings that can incorrectly calculate the capacity contribution of intermittent generators to reliability in the SWIS.

This is mainly because the method is not consistent with the assumptions underpinning the original simple formula. The current method does not address the effect of the relationship between the output of intermittent generators and demand: a main determinant of their capacity value. The current method was also developed based on complex statistical and mathematical techniques that are not well understood by generators and retailers in the WEM.

The current method could be revised to remedy some of its shortcomings. Even so, a fundamental problem will remain. The simple formula, upon which the current method was based, can only calculate reasonable capacity values for the fleet of intermittent generators when there are very low levels of intermittent generation in the electricity system.

With only a few intermittent generators present, the relationship between their output and demand would have a negligible influence on the capacity value of the intermittent generation fleet. This situation no longer applies in the SWIS, where the penetration of intermittent generators is increasing. The current method is no longer relevant.

A relevant level method that does not result in the allocation of capacity credits to intermittent generators that reflects their contribution to reliability in the SWIS can increase the long-term cost of electricity to consumers and undermine the reliability objective of the WEM.

The proposed relevant level method

The proposed method uses historical time series data on the output of intermittent and scheduled generators and demand to forecast the capacity value of the intermittent generation fleet two years ahead.

The proposed relevant level method would then allocate the fleet capacity value to individual intermittent generators based on their output during capacity shortage periods in the SWIS.

> The proposed method is based on the recommendations of the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers, Wind Power Coordinating Committee Task Force. The Californian Independent System Operator and the Midcontinent Independent System Operator also use a similar method for the capacity valuation of intermittent resources.

There are some problems with this proposed method. As with any forecasting tool, it assumes that historical data will provide a reasonable indication of the contribution of intermittent generators in the future. The method utilises a mathematical model that may be a 'black box' and not as transparent as a simple formula. However, the proposed method does not use restrictive assumptions or constant parameters such as are present in the current method.

Any problems with using the proposed method are outweighed by improvements in the accuracy of the capacity values it calculates. The proposed method uses historical data on demand and generation output, so does not rely on sampling an intermittent generator's output in certain trading intervals to calculate its capacity value. Neither is the proposed method restricted by the number of intermittent generators in the SWIS. It is independent of the generation mix and can continue to calculate capacity values for intermittent generators as the WEM evolves.

A method that allocates capacity credits to intermittent generators in a way that better reflects their contribution to reliability in the SWIS, will ensure the proposed method more effectively meets the WEM objectives.

Compared to the current relevant level method, the incremental computational burden and administration costs of the proposed method are negligible. The proposed method uses basic statistical and probability-based concepts.

The ERA has created a sample mathematical model to demonstrate the proposed method and modelling outcomes are provided in section 6.1. These show a higher capacity value for intermittent generators in many supply-demand combinations compared to the current method. The results also show that the capacity value of the fleet of intermittent generators in the SWIS varies substantially from year to year.

Next steps

The ERA is seeking stakeholders' views on:

- The proposal to replace the current relevant level method with the ERA's proposed method.
- How to determine a capacity value for intermittent generators that reflects their contribution to system reliability, given the volatility of annual results.
- Any other information pertinent to the review of the relevant level method.

For transparency, guidelines would be included in the Market Rules on how the proposed method should be implemented and what it should deliver. This would be supported by a detailed specification of the mathematical model used in the proposed method in a separate market procedure.

The ERA will take into account stakeholder feedback, received in response to this draft report, to finalise its review and any recommendation to change the relevant level method. This will be included in the final report, which must be published by 1 April 2019.

Following publication, any recommendation to change the relevant level method will be developed as a rule change proposal and a new market procedure. These may include transitional arrangements to smooth any financial impacts on market participants from changing the method.

While any proposed rule change and procedure are in development, the current relevant level method will continue to apply. On its website, the ERA will publish unchanged values for the two fixed parameters (*K* and *U*) used in the current method.

1. Introduction

Every three years the Economic Regulation Authority reviews the method by which the Australian Energy Market Operator (AEMO) certifies capacity credits for intermittent generators such as wind and solar farms. In the Wholesale Electricity Market (WEM) Rules this is called the relevant level method.[1]

The Independent Market Operator conducted the previous reviews in 2011 and 2014, and commissioned Sapere Research Group to assist in reviewing the method.[2]

This is the ERA's first review of the relevant level method. It began in April 2018 and must be completed before 1 April 2019. As part of the review, the ERA is:

- examining how effectively the relevant level method meets the WEM objectives
- determining the values of the parameters used in the method.

The ERA may also consider any other matters that it considers relevant.

This draft report outlines the ERA's findings and recommendations and is intended to assist interested parties to make submissions.

Following feedback from stakeholders, the ERA will prepare and publish a final report. The final report will contain details of the review, a summary of stakeholder submissions and the ERA's response to issues raised, and values for parameters to be used in the current relevant level method for the next three reserve capacity cycles.[3]

The ERA can submit a rule change proposal to the Rule Change Panel seeking amendments to the relevant level method.

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1 Appendix 9 and clause 4.11.2(b) of the Market Rules.

2 The next triennial review would have been completed by 1 April 2018. However, with transfer of the review obligation to the ERA, a transitional clause (1.17.5(d)) allows the ERA to complete its first review by 1 April 2019.

3 For the 2019 relevant level method review, these will be the K and U parameters to apply in the 2019, 2020 and 2021 reserve capacity cycles.

2. Background

The Wholesale Electricity Market (WEM) design includes a requirement to have sufficient capacity available to satisfy demand at all times, and to deal with supply emergencies. This requirement is captured in the reliability planning criterion[4] in the Market Rules. The Australian Energy Market Operator (AEMO) estimates the total amount of capacity required in the South West Interconnected System (SWIS) to satisfy the reliability criterion for a capacity year. This is the reserve capacity target.

Generation facilities and demand-side management providers (such as large industrial power users) that make capacity available to the system are eligible to receive capacity credits. A capacity credit is a notional unit of capacity expressed in megawatts that market participants can trade. AEMO assigns certified reserve capacity using the following methods specified in the Market Rules:

- Scheduled generators, such as coal or gas plants, receive capacity credits equal to their estimated sent-out capacity calculated at an air temperature of 41 degrees Celsius.[5]
- Intermittent generators, such as wind or solar farms, receive capacity credits based on the estimation method prescribed in the Market Rules – that is, the relevant level method.
- Demand-side resources receive capacity credits based on the amount by which they can voluntarily reduce their electricity consumption in response to a request by the system operator.[6]

For each capacity year, AEMO certifies and assigns capacity credits to eligible resources two years ahead of time. It then procures sufficient capacity credits from generation and demand-side resources to meet the reserve capacity target for that year.[7]

AEMO assigns an individual reserve capacity requirement to market customers based on their contributions to the system peak demand.[8] Electricity retailers and direct purchasers of energy fund the procurement of capacity in proportion to that contribution.

The total number of capacity credits allocated by AEMO determines the price of each credit. The greater the number of capacity credits allocated relative to the reserve capacity target, the lower the price. Capacity credit holders and buyers can also choose to trade capacity credits.

The capacity procurement method prescribed in the Market Rules ensures that the total supply of capacity can reliably cover forecast system peak demand.[9] The procurement process runs two years in advance to ensure that capacity can be made available on time. The number of

[4] Clause 4.5.9 of the Market Rules.

[5] Clause 4.11.1(a) of the Market Rules.

[6] Clause 4.11.1(j) of the Market Rules.

[7] The Market Rules apply different obligations on facilities depending on the technology type. Facilities must make their credited capacity available for dispatch by System Management. Except for intermittent generators, this obligation is in proportion to the number of capacity credits allocated to facilities. Facilities must comply with the outage planning and monitoring obligations and submit to tests of availability of capacity and inspections.

[8] Appendix 5 of the Market Rules specifies the calculation of individual reserve capacity requirements.

[9] AEMO also procures capacity to cover a reserve margin and minimum frequency keeping capacity. The capacity procured should also be sufficient to limit the amount of energy shortfalls. However, to date the requirement to meet peak demand has been the most stringent criterion.

capacity credits assigned to individual resources, including the intermittent generators, determines the total supply of capacity credits in the system.

The current relevant level method to allocate capacity credits to intermittent generators uses a formula to calculate the capacity contribution of individual intermittent generators, expressed in megawatts, using an adjustment to their average output during a sample of trading intervals.

2.1 Terminology and definitions

The rest of this report uses the term system supply adequacy to refer to an electricity system that has sufficient installed capacity available to meet demand at a set level of certainty. If the electricity system does not have sufficient capacity to cover demand, this would cause a loss of load. There would be an energy shortfall and the system operator would disconnect customer load to restore the balance between supply and demand.[10]

The overall probability that load will be lost in an electricity system is called the loss of load probability, or LOLP. The loss of load expectation, or LOLE, is the sum of loss of load probability over a planning period, usually one year. If a system has an oversupply of capacity, its loss of load expectation will be low.

In the SWIS, system adequacy is determined by the reliability planning criterion, which specifies there should be adequate available capacity in each capacity year to:

a. Meet the one in 10 year forecast peak demand plus a risk margin.

b. Limit expected energy shortfalls, or load unserved, to a certain amount of the annual energy consumption in the system.[11]

Part ‘a’ sets the requirement that the available capacity must meet peak demand to a given level of certainty. That is, forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded more than one year out of 10. These represent periods of very high demand, usually caused by very hot weather. To date, the SWIS has not experienced a one in 10 year forecast peak demand, as forecast by AEMO.[12]

The risk margin referred to in part ‘a’ of the reliability planning criterion is reserve capacity, over and above the forecast of peak demand, available to manage generation outages and still maintain normal frequency in the electricity system.[13]

Part ‘b’ in the reliability criterion specifies there should be adequate available capacity in each capacity year to limit any energy shortfall to 0.002 per cent of annual energy consumption.

[10] This is a simplified explanation. A system operator takes mitigation actions before disconnecting load. A well-functioning system should avoid using such mitigation actions regularly. Appendix 5 provides a detailed discussion of this point.

[11] The expected energy shortfall is the expected unserved energy, which refers to a forecast of the aggregate amount in megawatt hours by which the demand for electricity exceeds the supply of electricity.

[12] The highest demand in the SWIS in the past seven years was 4,004 MW, which occurred on 8 February 2016. In 2014 the Independent Market Operator forecasted that one in 10 year peak demand in the 2016/17 capacity year would be 4,149 MW and accordingly determined the reserve capacity target for the capacity year 2016/17. Peak demand in the SWIS is highly volatile and uncertain. Forecasting of one in 10 year peak demand therefore faces significant uncertainty. Observed peak demand may not reflect the extreme demand that is embodied in the one in 10 year peak demand forecast.

[13] The margin is calculated as equal to the greater of 7.6 per cent of forecast peak demand or the maximum capacity, measured at 41 degrees Celsius, of the largest generating unit.

Based on 2017 calendar year consumption of approximately 18.13 terawatt hours, the energy shortfall limit in the SWIS is 36.3 megawatt hours.

Currently, there is an oversupply of capacity in the SWIS when compared to the reserve capacity target, and the loss of load expectation and the expected unserved energy are low. AEMO estimated that the level of excess capacity in the SWIS, above the reserve capacity target, is 6.7 per cent for the 2020/21 capacity year and will decrease to 2.4 per cent by 2027/28.[14] Over time, the level of installed capacity is expected to trend towards the reserve capacity target with the loss of load expectation close to the system adequacy target (or reliability planning criterion) specified in the Market Rules.

Historically, part 'a' of the planning criterion has set the reserve capacity target in the SWIS. In its recent reports, AEMO has stated that it does not expect the second part of the planning criterion to become dominant in the next 10 years.[15] This is because currently the amount of unserved energy in the SWIS is substantially smaller than the threshold specified in the Market Rules.

[14] AEMO, *Electricity statement of opportunities*, Perth, Western Australia, 2018, pp. 48–49, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2018/2018-WEM-ESOO-Report.pdf.

[15] Ibid, p. 3.

3. Approach to the review

To understand the drivers of capacity valuation, the ERA explored different theoretical approaches, practical difficulties of data availability and calculation, and how other jurisdictions value capacity for intermittent generators.

The ERA then developed an assessment framework to guide the review. This incorporates the requirement in the Market Rules to assess how effectively the current relevant level method meets the market objectives. In its assessment, the ERA considered whether the current method results in the best assignment of capacity credits to intermittent generators based on available data, when compared to other methods.

If the estimates of capacity value for intermittent generators from the current relevant level method are inaccurate or biased, this limits how effectively the current method meets the WEM objectives. For example, if the capacity contribution of intermittent generators is overestimated, there may not be sufficient capacity available to meet the reliability target in the SWIS. This will undermine the reliability objective of the WEM.

Problems can arise from pursuing very accurate capacity valuations. The complexity of the valuation method may increase, the process can become less transparent, and the results can become more volatile. When developing an assessment framework for the review, the ERA sought to balance the need for accurate, unbiased estimates of capacity value against practical challenges of data availability and transparency.

3.1 Capacity valuation in theory

When reviewing how capacity is valued, the approach most widely used is effective load carrying capability. This values the capacity of a generator as equivalent to the quantity of additional system load that can be served by adding the generator to the electricity system whilst maintaining the existing reliability risk of the system, commonly measured through loss of load expectation.

The calculation of effective load carrying capability is dependent upon the variation of, and the relationship between:

- the available capacity of the generator for which capacity is being valued
- system demand
- the available capacity of existing generators in the electricity system.

In practice, these are all variable and a mathematical probability-based model is typically used to accurately estimate effective load carrying capability. Globally, jurisdictions with capacity markets tend to either model effective load carrying capability or use very simple techniques, such as sampling intermittent generator output over discrete time periods, to value capacity. Either way, effective load carrying capability tends to underpin capacity valuation.

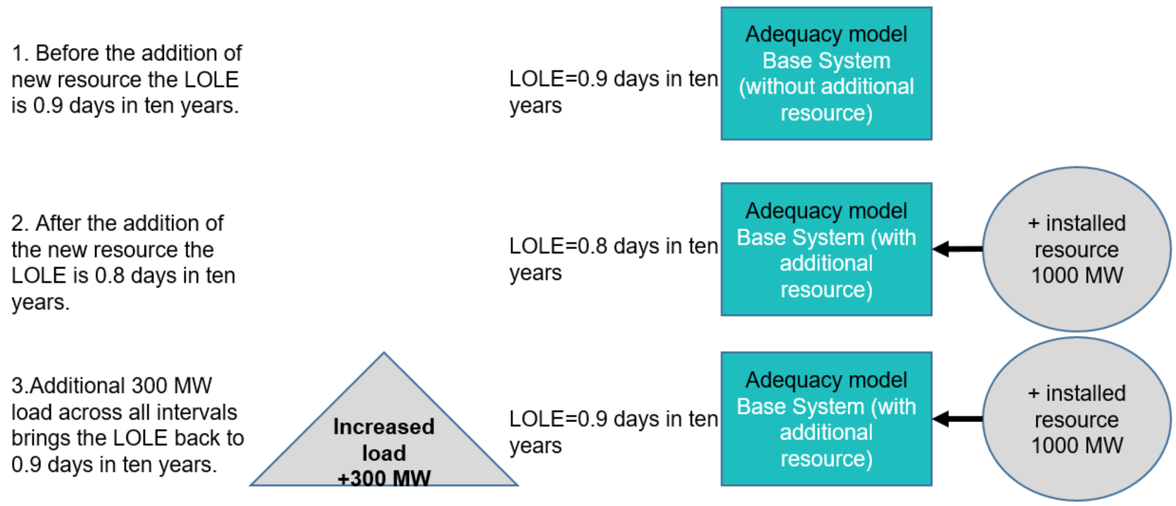
In a system comprised entirely of scheduled generators, the addition of another scheduled generator will reduce the loss of load expectation. As the available capacity of the scheduled generator has small variation, the amount of system load able to be serviced, or effective load carrying capability, will be similar, if not equivalent, to the installed capacity of the scheduled generator.[16]

In a system comprising both scheduled and intermittent generators, the available capacity is more variable and the output of some intermittent generators can be negatively correlated with demand as both are essentially weather dependent. Demand increases as air temperature rises and wind farm output can decrease. Calculating effective load carrying capability for intermittent generators is challenging, because their output is highly variable. To account for numerous different combinations of capacity output and demand in the system, a probability-based model of system adequacy should be developed. Appendix 3 provides a detailed discussion of the calculation of effective load carrying capability.

The calculation of effective load carrying capability using such model is illustrated in Figure 1. The effective load carrying capability is calculated in three steps. Step one shows the base electricity system. The loss of load expectation is 0.9 days in 10 years. In step two, a 1,000 MW intermittent generator is added to the electricity system. Adding the new generator improves the loss of load expectation, which drops to 0.8 days in 10 years. In step three, additional megawatt hours are added to system demand until the loss of load expectation reverts to 0.9 days in 10 years. The additional megawatt hours added is the effective load carrying of the new generator.

For the hypothetical system in Figure 1, a 300 MW addition to load brings the loss of load expectation back to 0.9 days in 10 years. The 300 MW addition to load is the effective load carrying capability of the new resource. The capacity value of the additional intermittent generator is 30 per cent of its installed capacity.

Figure 1. General process for the calculation of effective load carrying capability[17]



Source: adapted from MISO, 2017. Planning Year 2018-2019 Wind Capacity Credit, p. 5, https://cdn.misoenergy.org/2018%20Wind%20Capacity%20Report97278.pdf

16 When considered individually, the available capacity of a scheduled generator can vary, eg due to mechanical failures, and thus reduce its contribution to system reliability. However, scheduled generators as a fleet have very small variation in their output when compared to their average output. This is due the fact that their available capacity is largely independent of each other. The Law of Large Numbers dictates that the combined available capacity of every scheduled generator connected to the grid is far less volatile than the output of an individual generator, when compared to average available capacity.

17 ELCC is effective load carrying capability; LOLE is loss of load expectation.

The effective load carrying capability of a generator is determined by its contribution to lowering the loss of load expectation of the electricity system.

- A scheduled generator, which has most of its capacity available during the intervals when the loss of load probability in the system is the highest, would have a higher effective load carrying capability. Despite some variation due to forced outages, its effective load carrying capability or capacity value would be close to its installed capacity. Section A3.2, in Appendix 3 provides a detailed discussion of the capacity value of scheduled generators.
- In contrast, an intermittent generator would have variable output in the same intervals less than its installed capacity and so would have a lower effective load carrying capability than its installed capacity.

The loss of load probability in a trading interval is determined by both the level of demand and supply in the system. The surplus of capacity over demand is commonly referred to as 'system reserve'. The lower the system reserve in an interval, the greater the loss of load probability.

During a year, both demand and supply capacity are volatile. The output of an intermittent generator is volatile as it is dependent upon variable weather systems. System demand is becoming more volatile and difficult to forecast with the installation of rooftop photovoltaic systems, behind-the-meter storage, more efficient appliances and consumers reducing their electricity usage. A higher penetration of intermittent generators in the system increases the variability of capacity generally. In addition, the output of most intermittent generators is correlated with demand and other intermittent generators as explained in section 3.2.4. Demand rises with air temperature and the output of some intermittent generators reduces at very hot temperatures.

Practically, a model is needed to manage this volatility and correlation and calculate effective load carrying capability. There are some jurisdictions that model effective load carrying capability; these are discussed in section 0.

There have been attempts to simplify the calculation of effective load carrying capability. An example of this is the work by S. Zachary and C.J. Dent, who derived a relatively simple formula to approximate the effective load carrying capability of a generator. This is summarised in section 3.1.1. The formula used in the current relevant level method in the SWIS is an adaptation of the original Zachary and Dent equation.

3.1.1 Zachary and Dent approximation formula

In 2011, Zachary and Dent followed the general concept for calculating effective load carrying capability, as shown in Figure 1 and derived a relatively simple formula to approximate the effective load carrying capability of a supply resource or generator:[18]

Equation 1

$$ELCC = average\ output\ of\ resource - \lambda \times variance\ of\ the\ output\ of\ resource$$

The formula calculates the effective load carrying capability of an additional generator with an output that is:

[18] S Zachary & CJ Dent, 'Probability theory of capacity value of additional generation', in *Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability*, vol. 226, 2011, 33–43, http://dro.dur.ac.uk/11699/.

- independent of demand
- independent of the output of existing generators in the system.

The formula shows that effective load carrying capability is determined by the average and variance of the output of the resource and the parameter λ. The value of parameter λ is dependent on the probability distribution of the output of existing resources and demand and their correlation with each other.

Equation 1 can be used to calculate the effective load carrying capability of scheduled generators. The average and variance of the output of a scheduled generator during *all* trading intervals in a year or a couple of years, together with parameter λ, determine the capacity value of the generator.

Explanation

The average and variance of the output of the generator used in equation 1 are to be calculated during all trading intervals over a relatively long period, such as a year or several years.

This is in contrast to equation 2, as discussed further below, where average and variance are to be calculated during particular periods.

Except for some seasonal variation, the output of scheduled generators is mostly independent of the output of other generators in the system of demand. The variance of the output of these generators, as a group, is relatively small when compared to their average output. When installed in a summer peaking system, the effective load carrying capability of these generators is mostly determined by their average output during hot summer days.

Many intermittent generators have output that is negatively correlated with demand as both output and demand are weather-dependent to some extent. Equation 1 would not provide a reasonable estimate of the effective load carrying capability of intermittent generators.

Explanation

Assume a wind farm in South Australia is able to connect to the South West Interconnected System (SWIS). The output and variation of the South Australian wind farm would be mostly:

- uncorrelated with SWIS demand
- uncorrelated with the output of other intermittent generators in the SWIS.

The effective load carrying capability of the South Australian wind farm for the SWIS could be accurately estimated based on equation 1, using its historical output during *all* trading intervals in a year or several years.

However, equation 1 could not accurately estimate the capacity value of the wind farm if it was installed in Western Australia. The output of the wind farm in that case would be correlated with demand and the output of other wind farms in the SWIS.

Zachary and Dent modified their formula such that it could provide a reasonable estimate under some conditions, despite the correlation between the output of an intermittent resource and demand:[19]

Equation 2

$$ELCC = \textit{Average output of resource when the surplus of the capacity of existing resources in the system over demand is zero.} - \lambda \times \textit{Variance of the output of resource when the surplus of the capacity of existing resources in the system over demand is zero.}$$

The modified approximation formula above is based on output average and variance during certain periods only. The modification of the approximation formula is briefly explained in the box below. A full technical discussion of this modification is presented in Appendix 4.

[19] More accurately stated, they explained the formula would provide accurate results if the variability of the output of the intermittent generator is small when compared that for the surplus of the capacity of existing generators in the system.

Explanation

Zachary and Dent noted that the addition of a small intermittent generator to an existing system does not shift the periods with the highest loss of load probability.

For example, before the addition of intermittent generators in the SWIS the periods with the greatest demand had the highest loss of load probability. The addition of a small intermittent generator could not shift the periods with the highest loss of load probability. Therefore, the loss of load expectation of the system after the addition of a small intermittent generation was mostly determined by the loss of load probability during the same high demand periods as before the addition of the small intermittent generator.

It can be shown mathematically that equation 1 can be used under such situations with a slight modification. The average and variance of the output of the small resource should be calculated during the periods when the surplus of capacity in the system, before the addition of the small resource, is zero.

For instance, equation 2 can be used to accurately estimate the capacity value of the wind farm discussed in the previous explanation box. For this calculation, first the periods with zero capacity surplus, before the addition of the wind farm, should be identified. Second, the average and variance of the output of the wind farm during the identified periods should be calculated.

The value of constant parameter λ should also be estimated based on the statistical characteristics of the surplus of the capacity of existing resources over demand.

The basis of calculation in the current relevant level method is the modified approximation formula above. The current method uses equation 2 and includes a constant parameter U in the formula to address a lack of data for the available capacity of intermittent generators during extremely high demand periods. Intervals with peak load for scheduled generation are used to indicate the periods with the lowest level of surplus capacity over demand.

The Market Rules use the term ‘relevant level’ to refer to the effective load carrying capability of intermittent generators.

The ERA examined the derivation of equation 2 in detail:

- The formula cannot provide reasonably accurate results with increased penetration of intermittent generators in the system.
- The formula does not provide any practical or theoretical advantage when compared to numerical models.
- Noting the small size of the SWIS, the value of the constant parameter λ is highly sensitive to its calculation assumptions.

To the ERA’s knowledge no other jurisdiction uses the formula for the capacity valuation of intermittent resources.

The current relevant level method also contains numerous inconsistencies, inaccuracies and ad-hoc adjustments when compared to the theory and assumptions underpinning the development of equation 2, as explained in section 4 and Appendix 4.

3.2 Capacity valuation in practice

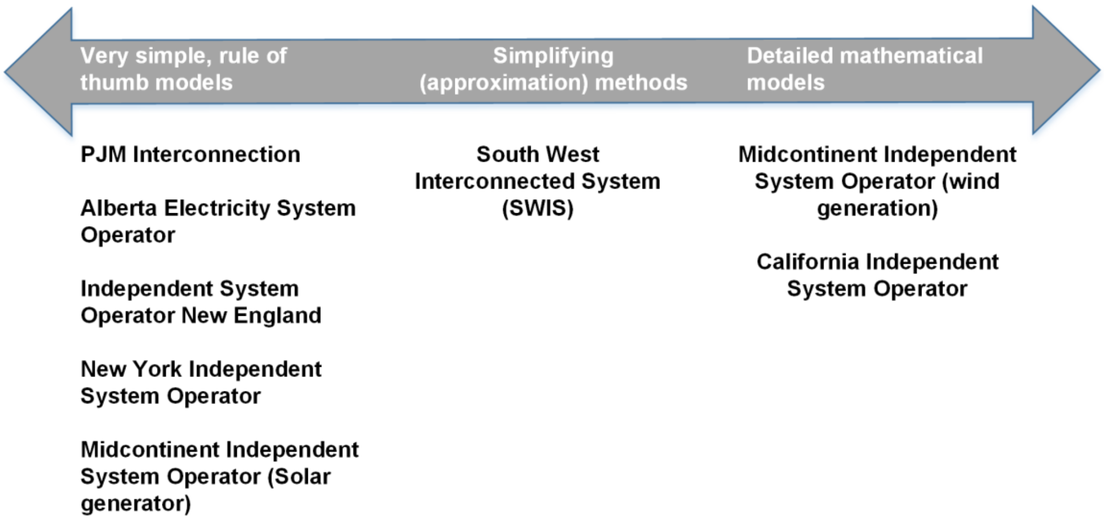
In practice, the methods used to calculate capacity value in other jurisdictions range from detailed mathematical models used to calculate effective load carrying capability to simple rule of thumb models that approximate effective load carrying capability.

There is no clear boundary between what constitutes a detailed mathematical model or a simplified approach. Instead, a continuum of methods has been developed to progressively reduce the complexity of detailed mathematical models. Typically, termed approximation or simplified models.[20] This is illustrated in Figure 2.

Generally, detailed mathematical models provide more accurate results when compared to approximation methods, although the basis of calculation in the approximation and detailed mathematical methods is the same.

Approximation methods use mathematical techniques and simplifying assumptions to approximate the result of detailed mathematical models using a simple formula. In comparison, detailed mathematical models do not use such simplifying assumptions and use numerical solution methods to provide more accurate results. This paper uses the term ‘numerical method’ to refer to mathematical methods that use numerical solution techniques. This is in contrast to less accurate approximation methods that use a simple formula to calculate capacity values.[21]

Figure 2. Capacity valuation of intermittent generators in practice



20 In its recommended practice for capacity valuation of wind resources, the International Energy Agency expert group states that the application of approximation methods can be justified by simplicity and lack of data. H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, p. 35, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8.

21 Approximation methods such as that developed by Zachary and Dent use analytic solutions to derive a ‘closed-form’ solution for the effective load carrying capability. Numerical methods use, such as that proposed by the ERA in this report, use numerical techniques to calculate effective load carrying capability.

3.2.1 Numerical models

The general process for the calculation of effective load carrying capability using a numerical model is similar to that previously explained in Figure 1:

1. A system adequacy assessment model is developed to estimate the adequacy risk of the system subject to possible demand and supply capacity scenarios. The choice of system adequacy risk measure should be consistent with the reliability planning criterion of the system. The model commonly uses the time series of demand, the output of intermittent resources, and the forced outage rate of scheduled generators.

2. Using the time series of demand and the model developed in step 1, measure the adequacy risk of the system. In this step, the output of intermittent resources is ignored to estimate the adequacy risk of the system without the contribution of intermittent resources.

3. The adequacy risk of system is measured, including the contribution of the fleet of intermittent generators. The measure of adequacy risk in this step would show improvement in the reliability of the system.

4. Fixed megawatt amounts will be iteratively added to the time series of demand in step 3 until the system adequacy risks in step 3 becomes equal to the one in step 2. The megawatts added to the demand time series represents the effective load carrying capability of the fleet of intermittent generators.

When compared to other available methods, numerical models can provide the most comprehensive model of system adequacy risk and accurate capacity value results, subject to the:

- accuracy of the inputs used in the modelling
- degree to which the details of the elements of the system are incorporated.

However, these numerical models are not particularly transparent in identifying what factors drive the capacity value outcomes,[22] and depending on the type of system adequacy model developed, they can become complex. Such a high level of complexity may decrease stakeholder engagement in the capacity valuation process.[23]

Among system operators around the world, the ERA identified two that use numerical modelling approaches to estimate the capacity value of intermittent generators: the Mid-continent Independent System Operator, which services the Mid-West United States of America and parts of Canada; and the California Independent System Operator.[24]

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22 CJ Dent, A Keane & JW Bialek, 'Simplified methods for renewable generation capacity credit calculation: A critical review', in *IEEE PES General Meeting, PES 2010*, 2010, 1–8.

23 Detailed probabilistic models in this context commonly refer to numerical models or simulations of system adequacy. We contrast such models with simplified models for capacity valuation: these are commonly models with closed-form expression for the calculation of capacity value. A closed-mathematical expression comprises finite number of simple operations on variables. For instance, the current relevant level method uses a closed-form expression for capacity value. It uses average and variance and constant factors to estimate the capacity value.

24 Refer to California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, pp. 8–10, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533 and Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–11, https://www.midwestiso.org/Library/Repository/Study/LOLE/2018 Wind Capacity Report.pdf.

After modelling the capacity value of the intermittent generation fleet, these system operators then use relatively simple methods to allocate the fleet capacity value to individual facilities.

3.2.2 Approximation methods

Approximation methods are used to calculate effective load carrying capability using simple formulas and a limited number of parameters. This provides transparency on which factors drive the calculation of capacity value for a facility. However, the basis of calculation for approximation and numerical models is the same. Approximation methods use simplifying assumptions to estimate capacity values using simple formulas.

The formula used in the WEM's current relevant level method is a simplified method for the calculation of effective load carrying capability. The current relevant level method is explained in more detail in section 4 and Appendix 4.

The ERA did review other examples of approximation methods.[25] These methods typically use probability-based models of output distributions rather than actual time series data and overlook the relationship between the output of intermittent generators and demand, or make implausible assumptions for the shape of the distribution of surplus capacity in the system. Many of these methods have limitations and are no longer used to estimate capacity value.

3.2.3 Rule of thumb methods

The approaches to capacity valuation used in the rule of thumb methods for calculating capacity value can reflect the concept of effective load carrying capability. An example is the time-based methods used in many jurisdictions. They calculate the capacity factor[26] of wind and solar generation during hours when the system may have the highest risk of capacity shortage to meet demand.

The Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the United States of America calculates the capacity value of wind and solar resources by estimating the average capacity factor of wind farms in certain peak demand time periods in summer and winter over the past three years. The selection of periods representing peak demand peak periods can and does change over time:

- Until 2017, PJM used the time periods from 3:00pm to 6:00pm during the summer months for the calculation.
- Recently, PJM changed the specification of peak time periods for the calculation. It now calculates facility capacity factors between 6:00am to 9:00am during winter and between 6:00pm to 9:00pm during January and February, and 3:00pm to 8:00pm in June, July, and August.[27]

Similar time-based methods have been adopted by the New York Independent System Operator and Independent System Operator New England. Recently, the Alberta Electric

25 These methods included Garver's graphical method and the Z-method. Refer to (i) L Garver, 'Effective Load Carrying Capability of Generating Units', in *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-85, 1966, 910–919, and (ii) K Dragoon & V Dvortsov, 'Z-method for power system resource adequacy applications', in *IEEE Transactions on Power Systems*, vol. 21, 2006, 982–988.

26 Capacity factor is the average power generated divided by the rated capacity.

27 For the capacity value of wind farms, solar farms, and storage facilities like hydroelectric dams, flywheels, or batteries, the PJM calculates the capacity factor over the periods 6am to 9am during winter and 6pm to 9pm during January and February, and 3pm to 8pm in June, July, and August

System Operator proposed using time-based methods to calculate the capacity value of variable generation resources.

Some time-based methods were developed in conjunction with detailed and probability-based numerical models. An early study for the New York State Energy Research and Development Authority developed a time-based method for the capacity valuation of intermittent resources. The choice of time periods used to calculate capacity factors aligned the outcomes of the time-based method with the outcome from detailed numerical modelling.[28]

Time-based methods are used to enhance the visibility of the calculation process. However, the accuracy of time-based methods is sensitive both to the number of hours used and the selection of time periods.[29] As electricity systems evolve, and system demand and supply profiles change, the results of time-based methods and detailed numerical models can diverge. For example, as the penetration of rooftop solar photovoltaic increases, system peak demand shifts from early afternoon to early evening. Therefore, a time-based method may need frequent changes to align its results with those of a more accurate model, as has recently happened in the PJM.

However, time-based methods may provide reasonably accurate results under some conditions, such as when:

- There are very small quantities of intermittent resources installed in the system.[30]
- The intermittent resources are geographically dispersed in the system so that their output is not related.[31]

In practice these conditions seldom occur in an electricity system.

3.2.4 Practical limitations

Calculating effective load carrying capability requires three main variables, and estimates of the relationship between those variables. These variables are system demand, the output of other generators and the output of the intermittent generator for which the capacity value is being calculated.[32]

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28 GE Energy, *The effects of integrating wind power on transmission system planning, reliability, and operations, Report on Phase 2: System Performance Evaluation, Prepared for: The New York State Energy Research and Development Authority*, Albany, New York, 2005, p. 7.16, https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Biomass-Solar-Wind/wind-integration-report.pdf.

29 Refer to M Milligan & B Parsons, 'A comparison and case study of capacity credit algorithms for wind power plants', in *Wind Engineering*, vol. 23, 1999, 159–166, http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.566.205&rep=rep1&type=pdf and SH Madaeni, R Sioshansi & P Denholm, 'Comparison of Capacity Value Methods for Photovoltaics in the Western United States', 2012, p. 18, http://www.osti.gov/servlets/purl/1046871/.

30 This can be explained using equation 2. At low penetration of intermittent resources, FD Munoz & AD Mills, 'Endogenous Assessment of the Capacity Value of Solar PV in Generation Investment Planning Studies', in *IEEE Transactions on Sustainable Energy*, vol. 6, 2015, 1574–1585.

31 This can be explained using equation 2. When the penetration of intermittent resources in the system is low and their output is independent, the capacity value of the fleet of intermittent resources will be mostly determined by their average output during the periods when the surplus of capacity in the system is zero. The variance of the sum of the output of the fleet of intermittent generators will be relatively small when compared to the average of the sum of their output.

32 System adequacy assessment studies commonly ignore the effect of transmission and distribution grid constraints: They assume that the grid is fully reliable. This has been a common assumption because the focus of system adequacy studies has been the adequacy of capacity resources over a relatively long period.

A capacity valuation method that best forecasts these three variables and their relationships, can provide the most accurate results for the capacity contribution of an intermittent generator.

In practice, historical data is typically used to estimate the relationship between the main three variables explained above. This is because the relationship is complex, and impractical to accurately model using forward looking data such as forecasts of wind speed and demand.

When calculating the capacity valuation of a wind resource, hourly demand and wind data are paired chronologically. Weather conditions underpin both the output of wind farms and demand. A hot and sunny but low wind day will increase demand, as air-conditioners are turned on in response to the heat but output from wind farms decreases. The chronological pairing of demand and output over a reasonably long period of time can capture the relationship between these two factors.

Using historical data can present two challenges for calculating capacity value. First, it may not suitably reflect future system conditions. In the SWIS, the level and variability of system demand can change quickly, as has been demonstrated through the rapid uptake of behind-the-meter resources like rooftop solar photovoltaic. Capacity contribution is only forecast for a short planning horizon of approximately two years. Therefore, assuming sufficient historical data is available, the forecast of capacity contribution may produce reasonably accurate results.

Second, historical data may not contain sufficient information about the available capacity of intermittent generators during extremely high demand periods in the SWIS. The capacity contribution of resources is mainly determined by the availability of their capacity during the periods when the surplus of capacity over demand is low; that is, the periods when the likelihood of the loss of load is the highest. It is highly likely that many periods with the lowest level of capacity surplus happen when demand in the SWIS is extremely high.

As required by the planning criterion of the Market Rules, AEMO procures sufficient capacity to ensure the system can cover a one in 10 year forecast demand. However, observed demand in the SWIS has never been very close to one in 10 year peak demand forecast and extremely high demand periods have occurred very rarely. It is not clear how intermittent generators would contribute to the supply of electricity when demand is as high as one in 10 year peak demand forecast.

Historical time-series data may not provide sufficient information about the output of intermittent resources when the loss of load is the greatest. This lack of relevant data can influence the accuracy of capacity value forecasting. This is particularly important because there is evidence that some intermittent resources have reduced output during extremely hot days when system demand is extremely high.[33,34]

Assessing the accuracy of a method is also challenging. The accuracy of a capacity valuation method cannot be assessed unless the outcomes of the method are repeatedly compared to the actual contribution of intermittent generators. The comparison of the outcomes of the

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[33] For instance, refer to Sapere's analysis of the output of intermittent generators in the SWIS and their correlation with system demand and air temperature. Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, pp. 48–52, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

[34] To address this limitation of data, studies have attempted to model the relationship between the output of intermittent generators and demand. For instance refer to S Zachary & C Dent, 'Estimation of Joint Distribution of Demand and Available Renewables for Generation Adequacy Assessment', 2014, 16, http://arxiv.org/abs/1412.1786. The ERA's review showed that attempts to address such forecasting challenges introduce their own complexities and uncertainties that may not necessarily result in more reliable forecasts for the capacity value of intermittent resources.

forecast method with the actual contribution of resources in a single year or for a few years cannot provide a reasonable indication of the accuracy of the method. The gap between model outcomes and actual data can simply be due to the variable nature of intermittent generation and its dependence on weather patterns.

These practical limitations create trade-offs for an accurate calculation of the capacity value of resources. These practical limitations are included in the assessment framework outlined below.

3.3 Assessment framework

The Market Rules specify that the ERA's review must assess how effectively the relevant level method meets the market objectives. These are to:

- promote the economically efficient, safe, secure and reliable supply of electricity
- encourage competition between generators and between retailers of electricity
- avoid discrimination against different technologies
- minimise the long-term cost of electricity to consumers
- encourage managing when and how much electricity is used.

Seeking to achieve a better method to estimate intermittent generation capacity values serves the objectives of the WEM. Flawed estimates can:

- increase the adequacy risk of the system:
  - If the capacity contribution for resources is overestimated, there may not be sufficient capacity available to meet the adequacy targets of the system.
  - This will undermine the reliability objective of the WEM.
- result in economic inefficiency:
  - If the estimation method undervalues the contribution of resources, excessive amounts of capacity would be procured.
  - This will not effectively meet the market objective to promote economically efficient supply of electricity in the SWIS. The cost of excess capacity procured will outweigh the benefits of having excess capacity in the system.
- encourage the entry of one technology type over another:
  - This will undermine the market objectives of technology neutrality and efficiency.

There are trade-offs in aiming for the highest level of accuracy in capacity valuation.

The calculation of a generator's contribution to system adequacy should be based on capacity valuation theory with minimal changes made to the capacity valuation method. Adopting subjective capacity valuation methods or making adjustments to theoretical methods can result in inaccurate capacity valuations.

Where practical limitations, such as lack of data or calculation complexity, require simplifications or adjustments to a capacity valuation method, the agency undertaking the capacity valuation should clearly identify and explain any assumptions it makes. This increases the transparency of the calculation process.

Developing complex models to improve the accuracy of capacity valuation can be costly, may require many assumptions that add to the uncertainty of results, decrease transparency and may require large quantities of data. The outputs of such models are accurate only to the extent that inputs are accurate. However, in practice many of these input variables are either unavailable or uncertain.

The relevant level method should factor in the trade-off between accuracy and simplicity.

- The benefits of using a detailed numerical model to generate accurate capacity valuations should be assessed against the costs of adding complexity to the method.
- A complex and less transparent capacity valuation method may deter the entry of resources and increase market administration costs.

Even with fairly accurate inputs, a capacity valuation method may still produce volatile results. By its very nature, the output of electricity from wind and solar farms varies with temperature and weather conditions. Electricity demand is also volatile and can vary substantially due to changes in weather conditions and consumption patterns. Variability in capacity and demand means that the calculation of capacity value for intermittent generators could vary substantially from year to year. This in turn would create volatility in the price of capacity credits and financial implications for all capacity resources in the system. Volatility in capacity credit prices can increase financial risk for market participants and detract from providing functional capacity price signals for investments. Over the long term, the cost of this additional risk will ultimately be passed to consumers.

The relevant level method should provide reasonably stable results that are not overly sensitive to small changes in the system.

- Unnecessary volatility in the total quantity and allocation of capacity credits can increase the cost of electricity supply to consumers.

The ERA considered the following questions when determining how effectively the current relevant level method was meeting the market objectives:

- Is the current method reasonably accurate?
- If the current method is reasonably accurate, is it possible to improve accuracy or simplicity, while maintaining its practicality?
- If the current method is not reasonably accurate, what methods could replace it?

It is also important that a capacity valuation method is robust to changes in the system, including the changes in demand and in supply technologies. The method may need to address the capacity valuation of storage technologies, given the expected uptake of these resources in the system. The final question was:

- To what extent is the current method, or any proposed alternative, suitable for determining the capacity valuation of storage?

4. Review of the current relevant level method

The current relevant level method is set out in Appendix 9 of the Market Rules. It is based on some adaptations to the original formula developed by Zachary and Dent as discussed in section 3.1.1, equation 2. The current method calculates the capacity contribution of individual intermittent generators, expressed in megawatts, using an adjustment to their average output during a sample of trading intervals:

Equation 3

$$Relevant\ Level\ (MW) = average\ output - \left(K + \frac{U}{average\ output}\right) variance\ of\ output$$

The product of the variance of the output of an intermittent generator and two constant parameters K and U determines the size of the adjustment to the average output of that resource. The higher the variation of the output of a resource and/or the values of the parameters K and U, which are the same for all intermittent generators, the lower the capacity contribution of that resource.

The ERA is responsible for estimating the value of parameters K and U for the next three years as part of its review of the effectiveness of the method.

The formula uses the average and variance of the output of intermittent generators during a sample of trading intervals in the previous five years. The sample comprises top 12 trading intervals from separate days, for each year in the previous five years, where demand net of the sum of the output of all intermittent generators are the highest. The Market Rules refer to the periods in the sample as trading intervals with peak load for scheduled generation, or peak LSG.

Parameters K and U

Parameter K is equivalent to parameter λ as in the original approximation formula in equation 2. Zachary and Dent showed that the value of parameter K can be calculated using the below formula:

$$K = \frac{f'(0)}{2f(0)}$$

where $f'(0)$ denotes the first derivative of the probability density function of the surplus of existing capacity over demand estimated at zero megawatt surplus of capacity. The term $f(0)$ denotes the probability density function of the surplus of capacity over demand estimated at zero megawatt capacity surplus.

In simple terms, the value of K depends on the probability distribution of demand and available capacity of existing resources and their correlation. For instance, the outage rate of scheduled generators affects the value of parameter K. Outage rates determine the probability distribution of the available capacity of scheduled generators.

In theory, the value of parameter K can be positive or negative. It is mostly positive in practice, resulting in a downward adjustment to the average output of an intermittent generator.

Parameter U is not part of the original formula. It was added to address a lack of data about the performance of intermittent generators during extremely high demand periods.

Sapere assessed the value of parameter U by estimating the ratio:

- of the change in load for scheduled generation, on days with peak LSG when air temperature was above 38 degrees Celsius,
- to the mean output of the fleet of intermittent generators during peak LSG trading intervals.

Using the current relevant level method, Sapere calculated the capacity value of the fleet of intermittent resources by setting the value of parameter K to zero and parameter U to 0.635. It argued that the capacity value calculated for the fleet of intermittent generators was very close to the amount of change in LSG on the highest temperature day in 2014.[35]

The ERA examined how closely the formula in the current relevant level method, as in equation 3, and its application aligns with the original formula and its defining assumptions as developed by Zachary and Dent (2011). A detailed technical discussion of this comparison is presented in Appendix 4.

In summary, the original formula is generally consistent with capacity adequacy requirements in the SWIS. The original formula estimates the effective load carrying capability of resources based on loss of load expectation as the measure of system reliability risk. The use of loss of load expectation is consistent with the dominant planning criterion in the South West Interconnected System (SWIS). That is, the requirement to have sufficient supply capacity to meet one in 10 year peak demand forecast.

[35] Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 59, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

If the formula used in the current relevant level method does not align with the defining assumptions of the original formula, then it is unlikely to produce reliable results for estimating capacity values.

Similarly, if any of the parameters used in the current level method have been incorrectly calculated then this can lead to over or under estimations of capacity values for intermittent generators.

As noted in the assessment framework, the more inaccurate or biased the estimated capacity value, the less likely the relevant level is to be meeting the market objectives.

The review identified that the current relevant level method is inconsistent with the main assumptions in the development of the original formula and contains numerous shortcomings. The current method estimates the capacity value of intermittent generators individually:

1. The method should therefore identify the periods with the lowest level of capacity surplus over demand before the addition of the intermittent generator for which the capacity value is being calculated. The method for the identification of such periods, being the highest peak LSG periods, does not exclude the output of the intermittent generator for which the capacity value is being calculated. If conducted correctly, peak LSG periods should be identified without the output of the intermittent generator for which capacity value is being calculated. This would result in multiple sets of peak LSG periods, as many as there are intermittent generators in the system. The method should also estimate the value of parameter K for the capacity valuation of each intermittent generator, separately. The value of parameter K depends on the surplus of the capacity of existing resources over demand, before the addition of the generator for which the capacity value is being calculated. Applied correctly, this would result in different values of K for the calculation of the capacity value of each intermittent generator. The current method, however, uses a single value for parameter K for the capacity valuation of all intermittent generators.

2. The calculation of the value of parameter K also contained implausible assumptions:

    a. It ignored the correlation between the output of intermittent generators and demand.

    b. It ignored variation in the output of scheduled generators.

    c. It contained an ad-hoc adjustment in the value of parameter K to address the problem explained in paragraph 1 above. This calculation, however, contained theoretical shortcomings. A detailed discussion of this problem is presented in section A4.4, Appendix 4.

3. The current relevant level method contains another ad-hoc adjustment, the parameter U, to address a lack of data:

    a. In the SWIS, periods of extremely high demand similar to one in 10 year peak demand, as forecasted by the Australian Energy Market Operator (AEMO), have seldom occurred. The performance of intermittent generators during such periods is uncertain. The calculation of capacity value uses observed demand and output of intermittent generators to estimate their capacity value. This observed data may not suitably reflect the contribution of intermittent resources during extremely high demand periods that are most likely to happen during hot summer days. Previous reviews of the relevant level method showed that many intermittent generators have reduced output during periods with high air temperature.

b. The addition of parameter U to address this problem is inconsistent with the original formula and the concept of effective load carrying capability. The assessment of the value of parameter U was based on the effect of intermittent generation fleet output on load for scheduled generation estimates during peak LSG days. The effective load carrying capability is not equal to change in the amount of load for scheduled generation.

c. The assessment of the value of parameter U was based on the contribution of the intermittent generation fleet on the single day with the highest air temperature during 2014. An assessment based on a single data point only contributes to significant uncertainty in the calculation of capacity values.

d. The method also applies a single value of parameter U to the capacity valuation of all intermittent generators. Intermittent generators have varying degrees of change in output with increase in air temperature, as also shown by Sapere's analysis.[36] The application of a single value of parameter U to all intermittent resources is not plausible.

e. The ERA's analysis shows that the sample of periods with high air temperature in the past five years is not small.[37] The periods with the highest level of demand are most likely to happen when air temperature is high. The output of intermittent generation during such periods can provide a reasonable indication of their output during extremely high system demand periods. In the SWIS, the highest demand periods in the past seven years occurred when air temperature was between 36.0 and 41.1 degrees Celsius, but not during the periods of maximum daily air temperature, which were typically higher. The increased penetration of rooftop solar photovoltaic has shifted periods of highest demand to later in the afternoon when air temperature tends to be lower. The addition of a parameter to adjust for the lack of data may not be required.

4. The treatment of new intermittent generators in the current relevant level method can reduce the accuracy of the capacity value calculation for existing intermittent generators. The calculation of capacity value for new facilities also contains shortcomings:

   a. The current method separates the calculation of peak LSG periods for existing and new facilities. This approach ignores the effect of the output of new generators on the capacity value of existing generators and can lead to overestimation of the capacity value of existing generators.

   b. When calculating the capacity value of a new facility, the method also ignores the effect of the output of other new facilities on the capacity value of the new facility for which the capacity value is being calculated.

The current relevant level method also estimates the capacity value of intermittent generation facilities individually. This can substantially underestimate the capacity contribution of the fleet of intermittent resources, as explained in the box below.

[36] Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 51, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

[37] Between 1 April 2012 and 1 April 2017, the number of days with daily maximum air temperature above 36 and 38 degrees Celsius was 130 and 64, respectively.

Explanation

The calculation of capacity value for each intermittent generator individually has computational and technical disadvantages. The calculation of effective load carrying capability for the fleet of intermittent resources is a common practice for both technical and practical reasons.

For instance, the California Public Utilities Commission, the Midcontinent Independent System Operator, the Institute of Electrical and Electronic Engineers, and the International Energy Agency Expert Group on Wind Resource Assessment use similar capacity valuation methods to estimate the effective load carrying capability of a fleet of intermittent resources. Zachary and Dent (2012) also used their approximation formula (equation 2), to estimate the capacity value of the fleet of wind resources in the United Kingdom.[38]

While it is desirable to calculate individual effective load carrying capabilities for each facility, facility-specific calculations would be highly sensitive to the output profile assumed for facilities. It is not practical to develop the output profile (distribution) of individual facilities that is as accurate as would be required to yield improved results using the sum of the output of individual generators. It would be difficult to come to a consensus on the choice of output profiles and their correlation with demand for individual facilities.[39]

For instance, for the capacity valuation of individual generators as in the current method, the calculation of value of K would be challenging. The calculation should estimate the output profile (probability distribution) of the output of other intermittent generators in the system and their correlation with each other and demand.

The calculation of fleet capacity value has technical advantages. When considered individually, resources contribute to the reliability of the power system with diminishing returns. For instance, the first solar farm that contributes to the adequacy of the system produces the highest benefit in terms of contribution to the reliability of the system. Subsequent solar farms with the same performance as the first solar farm produce lower benefits for the reliability of the system. The need for capacity in the middle of the day has already been met by the first solar farm.

In practice, facilities contribute to the reliability of the system simultaneously and there is no order in their contribution. If the capacity value of each facility is measured individually, it would be treated as the last facility added to the system, and thus would receive the lowest capacity value as it would have the lowest reliability contribution. If resources contribution is measured individually, their total contribution would be substantially underestimated.[40]

The practical and more accurate solution is to calculate the effective load carrying capability of the group of intermittent resources. For instance, the calculation of the value of parameter K for this case is straightforward. The surplus of capacity before the addition of the fleet of intermittent generators is only determined by the surplus of scheduled generators over demand. This can be modelled with a reasonable level of accuracy. The periods with the lowest level of surplus of capacity over demand, before the addition of the fleet of intermittent generators, happen during the highest demand periods.

These problems cause inaccuracy in the calculation of capacity values for intermittent generators. The ERA has concluded that the current relevant level method is not effective to meet the market objectives.

The ERA investigated whether the shortcomings discussed above could be remedied. This could be done by using the approximation formula to estimate the capacity value of the fleet of intermittent resources, as opposed to individual facilities. This could have provided technical and computational advantages as discussed in the explanation box above.

The ERA, however, found that such enhancements to the current method cannot result in a reasonable estimate of the capacity value of the fleet of intermittent generation because:

- The calculation of the capacity value of the fleet of intermittent generators using the approximation formula can result in inaccuracies. This is because of the high penetration of intermittent resources in the SWIS. As discussed in section 3.1.1, the approximation formula can only provide a reasonable estimate of the capacity value of a resource if the magnitude and variability of the output of the additional resource is small when compared to the variability of the output of existing generators over demand. In the SWIS the variability of the output of the fleet of intermittent resources is high when compared the variability of the surplus of the capacity of scheduled generators over demand.
- The value of parameter K for the calculation of the capacity value of the fleet of intermittent generators would be very sensitive to its calculation assumptions. This is because of the relatively small number of scheduled generators installed in the SWIS.[41]

As discussed in section 3.1.1, the original approximation formula does not provide any computational or theoretical advantage when compared to numerical models.

Based on this assessment, alternative options for the relevant level method are explored in section 5.

4.1 Main issues raised by stakeholders

The review also considered practical aspects of the current relevant level method. This included previous reviews of the method, what issues were identified at the time as important to stakeholders and how the method has changed over time. The ERA also reviewed the open rule change proposal by Collgar Wind Farm.[42]

To assist in its review, the ERA created a stakeholder working group and provided updates on progress to the Market Advisory Committee.

Two questions about the relevant level method have persisted since market commencement. These are:

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38 S Zachary & CJ Dent, 'Probability theory of capacity value of additional generation', in *Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability*, vol. 226, 2011, 33–43 (pp. 15–22), http://dro.dur.ac.uk/11699/.

39 California Public Utilites Commission, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources*, 2014, http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

40 California Public Utilites Commission, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources*, 2014, pp. 4–5, http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

41 The probability density function of the available capacity of scheduled generators in the SWIS is not smooth. The calculation of the slope of the function is very sensitive to the assumed curve fitted to estimate the slope.

42 Collgar Wind Farm, *Rule Change Proposal: Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03)*, Perth, Western Australia, 2018, https://www.erawa.com.au/cproot/18754/2/RC_2018_03—Rule Change Notice and proposal.pdf.

- When is capacity most valuable, during peak demand periods or lowest capacity surplus periods?
- Should capacity certification consider economic factors such as payments for capacity credits, capacity refund mechanism and obligations, the reserve capacity price, and financial implications of the allocation of capacity credits?

The next two sections expand on these issues and outline if or how the ERA has taken them into account in its review and recommendations.

4.1.1 When is capacity most valuable?

The SWIS is a summer peaking system. The highest system demand periods are likely to occur during hot summer days. When demand rises, the excess capacity in the system reduces and the loss of load expectation increases. The calculation of capacity value for scheduled generators reflects this. They receive capacity credits equal to their sent-out capacity at an air temperature of 41 degrees Celsius. It is highly likely that demand in the SWIS on hot days is high, whereas the available capacity of scheduled generators decreases with increases in air temperature.

The capacity value for intermittent generators is calculated when system load, net of all intermittent generators' output, is highest. AEMO determines the top 12 net load intervals in each of the past five years. Each intermittent generator's output average and variance over these intervals is used in the relevant level method calculation to determine its capacity credits. The highest net load intervals selected are referred to as peak load for scheduled generation (LSG) periods, or peak LSG periods.

Periods with the highest LSG are periods with the lowest level of the surplus of available capacity, comprising scheduled and intermittent generation capacity, over demand. By assuming that the variation of available scheduled generation capacity is negligible when compared to the variation of demand net of the output of intermittent generators, the periods with the lowest surplus of the capacity of all supply resources over demand occur when the load for scheduled generation is maximised.

Explanation

Over a trading interval the surplus of the capacity of existing scheduled generators, X, and existing intermittent resources, I', over demand, D, before the addition of an individual resource with capacity, I, is determined by three factors:

$$M = X + I' - D$$

where M denotes the surplus of existing capacity, being $X + I'$, over demand. By assuming that the available capacity of conventional generators is constant or has small variation,[43] the surplus of capacity over demand, M, is the lowest when the term $I' - D$ is the lowest, or alternatively when $D - I'$ is the greatest. With a slight variation, the term $D - I'$ is the load for scheduled generators in the current relevant level method.

The current method estimates load for scheduled generation (LSG) by deducting the output of all intermittent generators, including the one for which the effective load carrying capability is being calculated, from demand:

$$LSG = D - (I' + I)$$

This formula shows that the current definition of load for scheduled generation is not accurate in calculating the lowest level of the surplus of existing capacity over demand, when estimating the capacity value of individual intermittent generators. The load for scheduled generation calculation should exclude the output of the generator for which the effective load carrying capability is being calculated.

There is an open rule change proposal, from Collgar Wind Farm, challenging the use of load for scheduled generation for calculating capacity credits for intermittent generators.[44] Collgar Wind Farm argues that the use of peak LSG in the current relevant level method does not reflect the requirement for intermittent generators to make their capacity available during system peak periods.

Collgar proposes that the current relevant level method should be changed to calculate the capacity contribution of intermittent generators based on their contribution during the highest demand periods in the system. Collgar also argues that the current relevant level method is inconsistent with the calculation of individual reserve capacity requirements, which determines how retailers pay for capacity credits.[45] Collgar's proposal states that scheduled generators receive capacity credits based on their available capacity "during peak [demand] conditions…, and this provides a good approximation to their ability to provide capacity during IRCR [individual reserve capacity requirement] intervals".

The approximation formula used in the current relevant level method specifies that the average and variance of the output of the resource should be estimated during the periods the surplus of capacity of existing resources over demand is zero. The current relevant level method identifies the periods with the lowest level of surplus through the calculation of load for

43 The variation of the capacity of scheduled generators in practice is substantially smaller than that for demand net of the output of intermittent generators.

44 Collgar Wind Farm, *Rule Change Proposal: Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03)*, Perth, Western Australia, 2018, https://www.erawa.com.au/cproot/18754/2/RC_2018_03—Rule Change Notice and proposal.pdf.

45 AEMO calculates the individual reserve capacity requirements based on market customer's load during the three peak intervals on each of the four peak load days in the hot season.

scheduled generation. A selection of intervals based on peak LSG and peak demand would provide the same results if the variation in output from the intermittent generators is small when compared to the variation of the surplus of the capacity of scheduled generators over demand. This is more likely to happen at low penetrations of intermittent generation in the system. The periods with the lowest level of surplus of capacity over demand will be determined by the highest demand periods, rather than those with reduced output of intermittent generators.

Explanation

As shown in the previous explanation box, the periods with the highest load for scheduled generation, $D - I'$, would have the lowest level of capacity surplus. The load for scheduled generation increases by two factors:

- Increase in demand, D: at a constant level of the output of intermittent generators, I', the periods with the highest level of demand have the lowest level of capacity surplus.
- Decrease in the output of intermittent generators, I': at a constant level of demand, the periods with the lowest level of the output of intermittent generators have the lowest level of capacity surplus.

If the variation of the output of intermittent generators is small, the periods with the highest level of demand would have the highest level of load for scheduled generation and therefore the lowest level of capacity surplus. This is the case at low penetrations of intermittent generators.

With increased penetration of intermittent generators in the system, the periods with the lowest level of capacity surplus may happen when demand is high, but not necessarily the highest, and the output of intermittent generation is low.

The ERA tested this by using historical data from the beginning of the trading day on 1 April 2016 to the end of trading day on 31 March 2017 to compare which intervals would be selected using the two methods.[46] Table 1 presents the results of the analysis. Common intervals across the two methods are shaded.

[46] The selection of intervals from March to April is consistent with the current relevant level method.

Table 1. Comparison of methods for identification of capacity valuation intervals, 2016/17

Intervals	Peak LSG (existing facilities)	Peak demand
1	08/06/2016 18:00	21/12/2016 17:00
2	12/07/2016 18:30	1/03/2017 17:00
3	21/12/2016 17:00	4/01/2017 16:30
4	03/01/2017 17:30	7/06/2016 18:00
5	04/01/2017 16:30	3/03/2017 16:30
6	26/01/2017 16:30*	12/07/2016 18:30
7	28/01/2017 17:00*	3/01/2017 17:30
8	13/02/2017 17:30*	4/07/2016 18:00
9	19/02/2017 17:30	8/08/2016 18:00
10	25/02/2017 17:30	19/02/2017 17:30
11	01/03/2017 17:00	13/07/2016 18:30
12	03/03/2017 16:30	8/06/2016 18:00
Average of the sum of the output of all intermittent generators fully operational during the entire 2016/17 (MW)	96.1	154.5
Variance of the sum of the output of all intermittent generators fully operational during the entire 2016/17 (MW^2)	3122.3	2605.8

* The three peak LSG periods on 26/01/2017, 28/01/2017, and 13/02/2017 were the 14th, 15th, and 19th largest demand periods from separate days in 2016/17.

Source: the ERA's analysis based on AEMO's data

The shaded cells in the table show there is a large degree of overlap between the different sampling methods. This suggests that periods with the highest level of demand still determine many of the periods with the lowest level of surplus of capacity over demand. However, there are enough differences between each method to yield substantially different average capacity outputs for the fleet of intermittent generators.

Intervals identified based on the peak LSG and peak demand methods also identified intervals from winter and spring, suggesting that intervals with a high loss of load probability also occur outside the hot season when demand may be lower than during the summer peak.

In practice, at any point in time both demand and capacity are variable and therefore unpredictable. Over time, the volatility and correlation of demand and available capacity can change with technological innovation and customer behaviour. Therefore, the method used to identify periods with the greatest loss of load probability should consider the characteristics of demand and the output from scheduled and intermittent generators and their correlation. This can be illustrated by use of an example.

Assume a summer peaking electricity system where demand is served by scheduled generators, with relatively stable capacity and minimal rooftop photovoltaics. Although peaky, demand is fairly predictable and linked to air temperature. The output from each scheduled generator is independent of other generators and demand. The output from scheduled generators can be estimated at different air temperatures using de-rating curves. In this electricity system, the greatest risk of losing load would occur in peak operational[47] demand periods.

Now assume the same summer peaking electricity system but with considerable rooftop photovoltaic and a significant penetration of other intermittent generators, such as large scale wind and solar farms. Demand becomes more variable as rooftop photovoltaic reduces system load, mostly during the middle of the day. Intermittent generators, by their nature, have variable, weather-dependent output. A higher penetration of intermittent generation in the

[47] Operational demand refers to consumers demand net of behind-the-meter supply sources, such as rooftop solar that is served by large scale generators on the grid.

system results in greater variation in total capacity output. In addition, the output from intermittent generators is likely to be negatively correlated with demand as both are weather-dependent. During hot summer days, demand for electricity increases but the output of wind farms tends to decrease, as very hot sunny days are generally not very windy. In this electricity system, with greater volatility in demand and capacity, it is feasible that the greatest risk of losing customer load could occur outside of peak operational demand periods.

4.1.2 Should capacity certification consider economic factors?

During the ERA's review, some stakeholders[48] have questioned whether the capacity valuation method for intermittent resources should factor in some economic aspects of the provision of capacity through the reserve capacity mechanism or investment in generation assets generally. These include investment costs, cash flows for selling capacity credits and funding of capacity credits.

The reserve capacity mechanism applies different requirements to intermittent generators when compared to scheduled generators, as follows:

- Capacity credits are allocated to intermittent generators, scheduled generators and demand-side programs using different methods.[49] Scheduled generators receive capacity credits based on their sent-out capacity at air temperature of 41 degrees Celsius. Demand-side programs receive credits based on the amount by which the demand from load or aggregated loads can be curtailed.
- The reserve capacity testing requirements for intermittent generators are less onerous than for scheduled generators.[50]
- Intermittent generators are also not subject to capacity credit refunds, as is the case for scheduled generators when they fail to meet their capacity availability obligations.[51]

Stakeholders also observed that some intermittent resources may no longer need cash flows from the sale of capacity credits to make their investment economically feasible. The capital expenditure for these resources has decreased due to economy of learning. Some stakeholders also argued that the method for funding capacity credits procurement is based on peak demand consumption, whereas the current relevant level method is not based on contribution during peak demand periods, and therefore is not aligned with the funding mechanism.

The relevant level method estimates the physical contribution, in megawatts of capacity, provided by intermittent generators to the adequacy of the system. The guiding principle for the calculation of capacity values is the planning criterion in the market rules. The reliability planning criterion stipulates that AEMO should procure sufficient supply capacity to ensure that it can meet demand reliably. The reliability planning criterion does not specify any economic value or measure that AEMO must consider when procuring capacity.[52] The method

[48] For example, refer to Rule Change Panel, *Market Advisory Meeting Minutes, 13 June 2018*, , 2018, p. 8, https://www.erawa.com.au/cproot/19374/2/MAC Meeting 2018_06_13 - Minutes.pdf.

[49] Clause 4.11 of the Market Rules.

[50] Clause 4.25 of the Market Rules.

[51] Clause 4.26.1 (a) and (b) of the Market Rules.

[52] The ERA is aware that some other jurisdictions procure different capacity products as part of their capacity market design. For instance, the Pennsylvania, New Jersey, Maryland Interconnection (PJM) market procures two capacity product types based on operation flexibility through its capacity market auctions (refer to section A2.3, Appendix 2). The calculation of contribution of resources to different capacity product types would require differing capacity valuation measures and methods. However, the reserve capacity mechanism in the SWIS does not procure different generation capacity types.

for the calculation of capacity values does not reflect any explicit cost-benefit analysis or value of lost load calculation, nor does it consider least cost operation of the power system.

The ERA is aware of the economic implications of changes to the relevant level method to intermittent generators and also to scheduled generators.

If a change to the relevant level method certifies a greater number of capacity credits to intermittent generators, then capacity revenue increases, and vice versa. When the Independent Market Operator introduced the current relevant level method in 2011, the amount of capacity credits allocated to intermittent generators reduced by approximately 30 per cent. The new method was phased in over three years to smooth the financial implications for intermittent generators. A change to the current relevant level method may carry implications for capacity revenue and for future investment incentives. The implementation arrangements for any new method should manage such implications.

A change to the relevant level method that results in a greater supply of capacity credits from intermittent resources can cause a lower price for reserve capacity. This would affect capacity revenues for other generators in the market.

The economic aspects of capacity procurement are mostly policy-driven. The Minister for Energy has recently consulted on the pricing of capacity and the investments signals this provides. Proposed changes to capacity pricing are being included as part of a broader reform program in the WEM.

These wider economic considerations are outside of the scope of this review into a capacity allocation method. The only exception is smoothing any financial effect of changing the method over a transition period.

Other changes to the reserve capacity mechanism are proposed as part of the WEM reform programme, these are considered in section 5.5.

5. Alternative relevant level methods

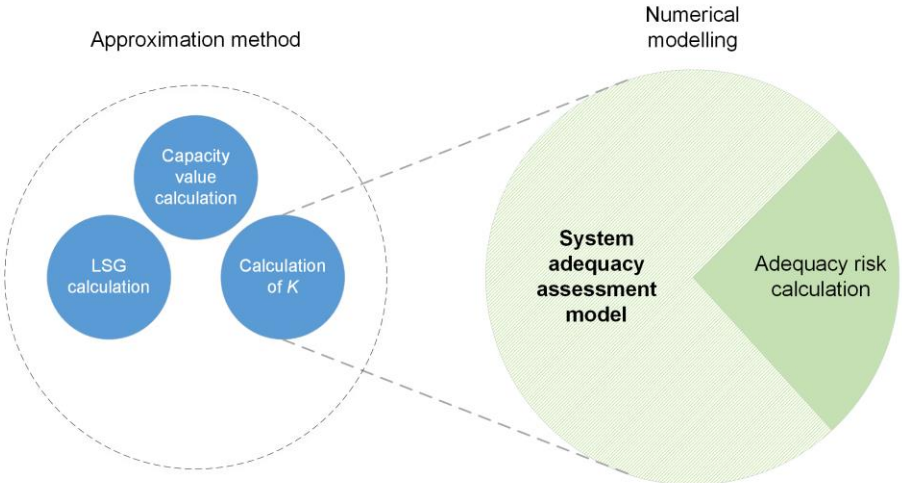
This review has found the current relevant level, described in section 4, is not fully meeting the market objectives. Consequently, the ERA has explored alternative options, to determine whether they could deliver more accurate estimates of the capacity value of intermittent generators. Four options are explored:

- Leave the current method unchanged for this review (option 1)
- Improve the current method (option 2)
- Develop a numerical model to determine capacity value (option 3)
- Move to a simple rule of thumb, time-based method (option 4)

The ERA concluded that only a method based on numerical modelling (option 3) is likely to provide reasonably accurate estimates. The adoption of a time-based method or an approximation similar to that currently used in the relevant level method will not be suitable. The inaccuracy of such alternatives is expected to increase as the penetration of intermittent resources in the SWIS increases.

Neither the current relevant level method, nor its enhanced version (option 2) provide significant transparency or computational advantage, when compared to numerical modelling. The calculation of parameter K would require a similar model to that developed for a numerical model, as illustrated in Figure 3. The development of a system adequacy assessment model is the most computationally intensive part of a numerical model. The same adequacy assessment model will also be required to calculate parameter K for use in the approximation method. Therefore, the incremental computation cost of a numerical model is negligible, when compared to the current approximation method.

Figure 3. Use of system adequacy models in the calculation of parameter K



The ERA recommends use of a numerical model. It will provide more accurate capacity values for intermittent generators and balances this with:

- reasonable implementation costs
- stable outcomes
- flexibility to withstand future changes in the Wholesale Electricity Market (WEM), such as the introduction of storage
- transparency.

The ERA's relevant level review is taking place at the beginning of a major program of reform in the WEM, which includes other changes to the capacity market. These changes have not influenced the ERA's recommendation to change the relevant level method. However, the ERA did consider these related activities as part of its recommendations for implementing the revised relevant level method, as explained in section 5.5.

5.1 Leave the current method unchanged for this review (option 1)

The current relevant level method could be retained without any changes until:

- the ERA next reviews the method in three years' time
- after the current market reform program has been completed.

This option represents the least administrative cost because AEMO has already automated the current relevant level method.

This option is not preferred as:

- The current relevant level method is inaccurate and contains theoretical shortcomings.
- When compared to the results of the sample numerical model discussed in section 6.1, the current relevant level method assigns relatively low capacity credits to intermittent generators.

5.2 Improve the current method (option 2)

The current relevant level method can be improved to ensure consistency with the underlying capacity valuation formula. It is impractical to calculate the capacity value of intermittent resources individually. However, it is possible and easier to estimate the capacity value of the fleet of intermittent resources:

- The calculation of the capacity value of the fleet, as a group, would require a single set of trading intervals with the lowest level of capacity surplus over demand.
- Periods with the greatest demand would have the lowest level of surplus of capacity.[53]
  - Before the addition of the fleet of intermittent generators, the surplus of the capacity of scheduled generators over demand is the lowest when demand is the greatest.
  - To calculate capacity value, the average and variance of the output of the fleet of intermittent generators should be estimated during peak demand periods during the hot season. The available capacity of scheduled generators has some variation over a year, where they have a smaller capacity available during the hot season when the air temperature is higher.
- The calculation of the parameter K for the fleet of intermittent generators is feasible. The value of K can be determined by the statistical characteristics of the surplus capacity of scheduled generators over demand.

Improving the current relevant level method would require:

53 This is similar to using zero for the output of intermittent generators in the calculation of LSG. Before the addition of the fleet of intermittent resources their output in the system is zero.

- Recalculating the values of parameter K – to do this a capacity outage probability table, similar to that required for the numerical model discussed in option 3, would need to be developed.
- Developing an allocation method to assign the capacity value of the fleet to individual resources. In other jurisdictions, this is based on some approximation; for example, individual intermittent generators would receive a proportion of the fleet capacity value based on their individual output during peak demand periods.

This option is not preferred as:

- It does not appear to have any substantial computational advantage when compared to numerical modelling, given a capacity output probability table is required for both.
- The size and variation of the output of the intermittent fleet is relatively large when compared to the size and variation in the surplus capacity of scheduled generators over demand. As discussed in Appendix 4, this can lead to inaccuracy of results.
- The value of parameter K is highly sensitive to assumptions made in the calculation. Applying different assumptions can result in materially different capacity values for the intermittent generation fleet.[54]

5.3 Develop a numerical model to determine capacity value (option 3)

A probability-based numerical model similar to that recommended by the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers could be used to estimate the capacity value of the fleet of intermittent resources.[55,56]

The Californian Independent System Operator and the Midcontinent Independent System Operator use a similar method for the capacity valuation of intermittent resources. Appendix 5 provides a detailed discussion of a numerical model.

An allocation method, similar to that used for option 2, would be required to assign the capacity value of the fleet to individual resources.

The ERA proposes to use this option:

- It can provide the highest level of accuracy among the options. The method does not require using assumptions similar to that used for the approximation methods. Approximation methods have been developed to approximate the output of numerical models. Their level of accuracy cannot surpass the accuracy of numerical models in forecasting capacity values.

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54 The value of K is determined by the slope of the loss of load expectation function. This function for a small system such as SWIS is not smooth and can have discontinuities. The value of K would be highly variable if it is directly derived from the function. Alternatively a curve can be fit over the loss of load expectation function. Depending on the form of the fitted curve, the value of K would vary significantly.

55 H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, pp. 35–36, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8.

56 Zachary and Dent also used a probabilistic model similar to the one preferred by IEA and IEEE to assess the accuracy of their proposed approximation formula in the capacity valuation of the fleet of wind resources in the United Kingdom.

- The calculation of capacity values would be based on numerical techniques, rather than a formula. The distinction is that a numerical technique uses a data driven model of the adequacy of the system to estimate the adequacy risk of the system with and without the contribution of the fleet of intermittent generators rather than a formula to make the same estimation.
- Although a numerical method appears more complex than the current relevant level method, developing such a model:
  - may not substantially increase the administration costs of the relevant level method
  - would increase the transparency of the relevant level method. A simple numerical model is based on basic probabilistic and mathematical concepts. In comparison, the development of approximation methods, similar to that developed by Zachary and Dent, is based on complex mathematical and statistical concepts and restricting assumptions.
  - is based on conventional system adequacy assessment models, which are common in many jurisdictions.

5.4 Move to a simple, rule of thumb method (option 4)

Similar to the practice in some North American jurisdictions, the capacity value of individual intermittent generators can be calculated using their average output during some specified periods. The method calculates the capacity value of an individual intermittent generator in two steps:

1. The method identifies the trading intervals with the highest probability of loss of load.
2. The average output of an intermittent generator during the periods identified in step 1 determines the capacity value of the generator.

A time-based method can provide stable results and is simple to implement and transparent. However, it is not expected to provide reasonably accurate results for the capacity value of intermittent resources in the SWIS. Time-based methods estimate the capacity value of intermittent resources by their average output during some certain periods when the loss of load probability is the greatest. With increased penetration of intermittent generation the periods with the highest loss of load probability shift across day hours and seasons. The method should periodically review and set those periods. The method also ignores the effect of the variability of the output of intermittent generators on their capacity value. These problems were discussed in detail in section 3.2.3.

As explained in section 3.2, reviewing the practice in other jurisdictions showed that the adoption of time-based methods has been in conjunction with probability-based numerical models. The specific time periods selected for time-based methods were amended until the capacity value outcomes determined from these periods approximated the results of a probability-based model.

This option is not preferred as:

- It does not appear to have any substantial computational advantage when compared to numerical modelling option, given a probability-based model is required for both.

5.5 Other considerations

The relevant level method needs to take into account changes that are under way in the SWIS. For instance, the relevant level method should be technology-neutral so that emergence of new technologies, such as battery storage, would not require further changes. Some Market Rules and processes have direct or indirect interactions with the relevant level method, changes in which may require changes in the capacity valuation of intermittent resources.

This section discusses how the relevant level method interacts with other Market Rules and arrangements that may change in the coming years. It also discusses the emergence of battery storage technology and its implications.

5.5.1 Reliability planning criterion

The reliability planning criterion in the Market Rules affects the calculation of the capacity value of resources. The Market Rules require the ERA to review the planning criterion at least once every five years. Changes to the planning criterion may require changes to the relevant level method.

To ensure consistency between the relevant level method and the planning criterion, the timing of the reviews of the planning criterion and the relevant level method could be aligned. This would require a change to the Market Rules.

5.5.2 Reserve capacity mechanism and capacity pricing

The market reform program is proposing several changes to the design of the reserve capacity mechanism; changes to capacity pricing and assigning capacity credits under constrained network access.[57]

In its consultation paper for improved pricing of capacity credits[58], the Public Utilities Office stated that:

> "it will remain the role of the ancillary services market to procure energy required for system security…" and therefore "…the capacity market will continue to procure reliability; i.e. the availability of capacity resources to meet peak demand. Capacity resources will be certified and allocated capacity credits based on their contribution to servicing peak load demand."

The purpose of the reserve capacity mechanism would not change as part of the reform program.

Changes to capacity pricing under consideration by the Public Utilities Office may not carry any implications for the relevant level method. Changes to capacity credit pricing may affect

[57] At its meeting on 9 May 2018, the Market Advisory Committee discussed whether network security constraints should be considered in process for assigning reserve capacity credits. Refer to Rule Change Panel, *Market Advisory Committee meeting minutes, 9 May 2018*, pp. 6–12, https://www.erawa.com.au/cproot/19208/2/MAC Meeting 2018_05_09 -Minutes.pdf.

[58] Public Utilities Office, *Improving Reserve Capacity pricing signals – alternative capacity pricing options, Consultation paper*, 2018, p. 4, https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Improving-Reserve-Capacity-pricing-signals.pdf.

cash flows for intermittent and scheduled generators, but such economic considerations are out of scope for the relevant level method review.

5.5.3 Constrained network access

In its consultation paper for allocating capacity credits under a constrained network design, the Public Utilities Office proposed that it would address the effect of network constraints by running a model that estimated the capacity contribution of resources subject to network constraints. The proposed model would assess “the ability of each generator on the system to simultaneously export its power into the network under the expected peak demand load scenario while seeking to “maximise reserve capacity””.[59]

As an input, the model would assume that intermittent resources operated at their relevant level of capacity, as assessed in accordance with the relevant level method. It appears that the proposed method to allocate capacity credits under a constrained network design will address the effect of network constraints on the capacity value of resources separately from the relevant level method.

5.5.4 Batteries

The market rules specify separate processes for the allocation of capacity credits to scheduled generators, intermittent generators, and demand side sources. It is not clear if and how storage facilities can receive capacity credits.[60]

The capacity valuation of storage facilities, such as hydroelectric dams, in other jurisdictions is more developed because the technology has been available for a long period. However, the technology for battery storage facilities is currently under consideration in many jurisdictions. Accommodation of battery storage technology in the capacity markets is a topical issue. For instance, the Pennsylvania-New Jersey-Maryland Interconnection is currently reviewing the potential participation of storage technologies in its capacity market.[61]

Energy storage can serve costly peak hours, quickly respond to system fluctuations, and provide several retail and wholesale services in addition to resilient power for customers. However, energy storage can only provide energy for a limited amount of time before it must stop to recharge, or refuel, or for other operational reasons.

For instance, if the existing reserve capacity obligations applied to storage technologies, they would face the risk of significant penalties. The physical characteristics of these resources, particularly their maximum run time,[62] is different to those for scheduled generators or hydroelectric facilities. To mitigate this risk, energy storage resources must significantly de-rate their capacity. This approach may not reflect the full capacity value of these resources and can prevent their participation in the reserve capacity mechanism.

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59 Public Utilities Office, *Allocation of capacity credits in a constrained network, Consultation paper*, 2018, p. 8, https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Allocation-of-capacity-credits-in-a-constrained-network.pdf.

60 Clause 2.29.2 of the Market Rules does not allow a facility to be registered both as a generation and load. This creates a barrier for the entry of storage technologies as a market participant.

61 B Watson, ‘Comments of Tesla, Inc. to PJM, Markets and Reliability Committee’, 2018, pp. 1–3, https://www.pjm.com/~/media/committees-groups/committees/mrc/20180802-special/20180802-comments-of-tesla.ashx, [accessed 22 November 2018].

62 Maximum run time for a battery is the duration between fully charged and discharged states, when a battery discharges electricity.

An alternative for their participation in the reserve capacity market is to value their capacity through the relevant level method. As explained in section 3.1 and Appendix 3, the relevant level method is based on the estimation of the contribution of generators to the adequacy of the electricity system. The calculation concept is technology neutral, for example it can be applied to calculate the capacity contribution of scheduled generation, storage, and demand side sources.

If battery storage facilities directly participated in the reserve capacity mechanism, the relevant level method would require an estimate of their output to calculate capacity values. Battery storage facilities may also be embedded behind the meter at a wind farm or solar farm and change the output of that intermittent generator. The capacity value calculation in either of cases would be similar to that conducted for new or upgraded intermittent facilities.

6. Proposed numerical model

The model estimates the effective load carrying capability of the fleet of intermittent resources in four steps:

1. Calculate the output distribution of scheduled generators using their maximum capacity and equivalent forced outage rates. The model uses an iterative method to estimate the probability of a certain amount of scheduled capacity being on outage.[63] This provides a reliability model, referred to as a capacity outage probability table of the system. The capacity outage probability is a table of outage states, expressed in megawatts, and their respective probabilities. The table also shows the probability of having a capacity outage greater than a given amount.

2. Use the capacity outage probability table in conjunction with the demand time series to calculate the loss of load expectation of the system. This represents the loss of load expectation of the system without the contribution of the fleet of intermittent resources.

3. Intermittent resources' output cannot be adequately modelled by their capacity and forced outage rates, because their capacity availability is mainly driven by wind speed or solar irradiance. Instead, use the time series for the sum of the output of intermittent resources and deduct it from demand to estimate a net load time series. The loss of load expectation of the system in this step would be lower than that estimated in step 2, because of the contribution of the fleet of intermittent resources to the system.

4. Iteratively increase load across all trading intervals by a fixed amount until the loss of load expectation in step 3 reaches the loss of load expectation calculated in step 2. The increase in load in this step is the effective load carrying capability of the fleet of intermittent resources.

These calculation steps reflect the definition of the effective load carrying capability. By the addition of the fleet of intermittent generators, the system can support the additional load estimated in step 4 without a change in the adequacy risk of the system, as estimated in step 2.

The proposed method is based on the recommendations of the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers, Wind Power Coordinating Committee Task Force.[64,65] The Californian Independent System Operator and the Midcontinent Independent System Operator also use a similar method for the capacity valuation of intermittent resources.[66]

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63 The capacity of any resource other than an intermittent generator should be reflected in the capacity outage probability table. For instance, demand side management resources would influence the reliability of the system and will be captured in the model. For simplicity in explaining the approach, however, we assume scheduled generators and intermittent resources comprise the total available capacity in the system.

64 H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8; and A Keane et al., 'Capacity Value of Wind Power', in *IEEE Transactions on Power Systems*, vol. 26, 2011, 564–572, http://ieeexplore.ieee.org/document/5565546/.

65 Zachary and Dent also used a probabilistic model similar to the one preferred by IEA and IEEE to assess the accuracy of their proposed approximation formula in the capacity valuation of the fleet of wind resources in the United Kingdom.

66 California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533; Midcontinent Independent System

The method is similar to conventional system assessment methods that use a capacity output probability table to assess the adequacy of a system comprising scheduled generators. The calculation of capacity output probability is well-known in reliability assessment modelling and is explained in several sources.[67]

The calculation of the capacity output probability table uses two main input data: maximum capacity of scheduled generators and equivalent forced outage rate of facilities. The Australian Energy Market Operator (AEMO) calculates the equivalent forced outage rate of scheduled generators for the purpose of clause 4.11.1(h) of the Market Rules.[68]

The fleet capacity value calculated is allocated to individual intermittent generators based on their historical capacity factor.[69] The allocation method ensures that the sum of capacity credits assigned to individual resources equals the fleet capacity value estimated through the numerical model. This approach is similar to that conducted by the Midcontinent Independent System Operator.[70]

The method uses the average capacity factor of generators during two sets of trading intervals:

- the top 12 trading intervals with the highest demand from separate days in each year in the past five years
- the top 12 trading intervals with the highest demand net of the output of the intermittent generation fleet, estimated for separate days, in each year in the past five years

Those resources with a greater capacity factor during the peak demand and peak net demand periods selected above would receive a higher proportion of the fleet capacity value.

Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–14, https://cdn.misoenergy.org/2018 Wind Capacity Report97278.pdf.

67 For example refer to R Billinton & RN Allan, *Reliability Evaluation of Power Systems, Second Edition*, New York, Springer US, 1996, https://www.springer.com/gp/book/9780306452598.

68 The calculation of equivalent forced outage rate of facilities is explained in Appendix 1 of AEMO, 'Power System Operation Procedure: Facility Outages', 2014, pp. 1–18, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/facility-outages-psop528697C8E166.pdf.

69 Capacity factor of a generator is the average power generated divided by the maximum capacity of the generator.

70 Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–14 (pp. 10–14), https://cdn.misoenergy.org/2018 Wind Capacity Report97278.pdf.

Why two sets of trading intervals?

The allocation of fleet capacity value to individual generators based on the two sets identified above is important. The capacity factor during the peak demand set reflects the contribution of intermittent resources to shifting the periods with high loss of load probability from the highest demand periods to other periods.

If the allocation method was based on the capacity factor during peak demand only, it could underestimate the contribution of resources that have a high contribution during the periods when demand is high, but not necessarily highest, and the output of other intermittent generators is lower.

For example, with increased penetration of solar farms, the periods with the highest loss of load probability shift from early to late afternoon, when wind farms typically tend to have higher output but solar farms have lower output. The allocation method proposed accounts for this effect.

Details of the development of the proposed numerical model and allocation method are presented in Appendix 5. The ERA developed a sample numerical model to calculate the capacity value of the fleet of intermittent generators in the South West Interconnected System (SWIS) for the 2019/20 capacity year. The calculation results are presented in the following section.

6.1 Sample numerical model

The sample model estimates the capacity value of the fleet of intermittent generators in the SWIS for the 2019/20 capacity year. It includes all intermittent generators that received capacity credits from AEMO for that capacity year. This sample model thus provides the opportunity to make a comparison between the results of the proposed method and the current relevant level method.

The sample model investigates two scenarios:

- Entire year time series scenario uses synchronised time series of demand and output of intermittent resources for each trading interval in the period between trading days 1 April and 31 March for each year from 2012 to 2017.[71] The scenario calculates the capacity value of the fleet of intermittent resources for six sampling periods comprising one for each year in the five-year period and one based on the entire 5-year sample.
- Hot season time series scenario is run similar to the previous scenario, except it uses data from the hot season only. Under the Market Rules, the hot season is the period commencing at the start of the trading day beginning on 1 December and ending at the end of the trading day finishing on the following 1 April.

Figure 4, panels (a) and (b) present intermittent generation fleet capacity value results for the scenarios above. The figure illustrates how the capacity contribution of intermittent generators in the SWIS varies from year to year. Annual results for both scenarios vary between 179 MW and 377 MW. The last bar on the right hand side of the graphs shows the capacity value result based on the entire five-year sample, which is equal to 250 MW in both tested scenarios.

The outcomes of the current relevant level method are only comparable to the lowest of the annual capacity value results based on the ERA’s proposed method. For the same capacity

[71] The selection of time series is consistent with the current relevant level method.

year as tested in this sample model, and using the current relevant level method, AEMO assigned approximately 183 MW of capacity credits to intermittent resources.

Results for the entire year and hot season scenarios are almost identical, indicating that the capacity contribution of intermittent resources in the SWIS is mainly determined by their performance in the hot season period. Model results show that loss of load expectation of the system in the hot season is only slightly lower than that estimated in the entire year scenario. The adequacy risk of the system is almost entirely determined by the loss of load probability of the trading intervals in the hot season.

This result confirms that for the calculation of capacity value the selection of entire year time series is appropriate as discussed in section A5.3, Appendix 5. The use of hot season time series does not provide any advantage to address a lack of data. Even if time series lack data about the performance of intermittent generators in the extremely high demand periods, the loss of load expectation in the off-peak period is substantially low that does not influence the capacity value results. This is explained further in the box below.

Explanation

The loss of load expectation of the system can be considered as the sum of the loss of load expectation during the hot season and non-hot season, or off-peak, periods. The loss of load expectation of the system based on the entire year time series scenario is almost equal to that for the hot season time series scenario. This indicates that the loss of load expectation during the off-peak period is negligible.

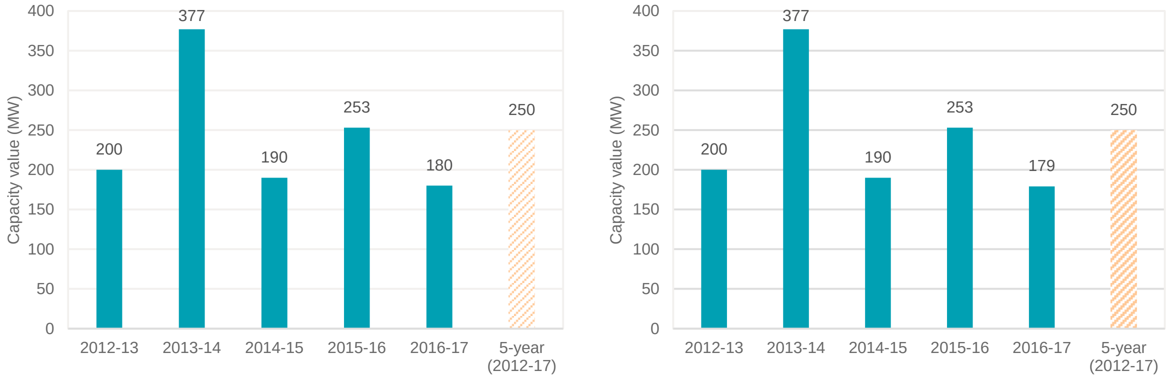
The sum of the loss of load probability of the trading intervals during the hot season almost entirely determines the loss of load expectation of the system in the SWIS.

Observed demand and intermittent generation output data may not contain sufficient information about the performance of intermittent generators during extremely high demand periods. Therefore, it is possible that the capacity value results will be influenced more by the performance of intermittent generators in non-highest demand periods than if the observed data did include periods of extremely high demand.

For instance, the loss of load probability of high demand periods, but not necessarily the highest demand periods, in a winter period may determine a higher portion of the loss of load expectation of the system. If sufficient data was available on the output of intermittent generators in extremely high demand periods, then high demand periods in winter could not make a significant contribution to the loss of load expectation of the system. A lack of data for the performance of intermittent generators during extremely high demand periods can influence the capacity value outcomes.

The difference between the annual capacity values in the sample period is driven by inter-annual variation in the two main inputs to the model: demand for electricity varies by several factors including weather patterns, economic condition and technological changes; the available capacity of many intermittent generators changes by weather conditions.

Figure 4. Estimated capacity value of the fleet of intermittent generators using the proposed method, 2019/20 capacity year, entire year and hot season time series scenarios



panel (a): entire year time series scenario

panel (b): hot season time series scenario

This variation of capacity value creates significant uncertainty for forecasting the capacity value of intermittent resources two years ahead of a capacity year. For instance, if the forecast uses the time series in 2016/17 period only, the estimated capacity value would be 180 MW. However, results show that this value is the minimum of the capacity value estimates in the five year period and may underestimate the capacity contribution of resources in the 2019/20 capacity year. For example, in 2019/20 it is possible that intermittent generators' contribution will be comparable to that in the 2013/14 period, (377 MW).

Alternatively, the forecast capacity value can be estimated by averaging the annual capacity values during the five year period. This gives a forecast capacity value of 240 MW. However, given the small size of the sample, the average of the capacity values is very sensitive to the relatively high capacity value result in the 2013/14 period.

The volatility and therefore uncertainty of results could be remedied by including more sample years of data in the analysis. The inclusion of multiple years of time series of demand and capacity output, however, has trade-offs. First, many intermittent generators in the SWIS were installed relatively recently. Actual output data for many of these resources is limited to the last few years. A larger sample of years would require estimate of the output of new or upgraded resources. These estimates introduce uncertainty in the calculation and increase the administration costs of the calculation process. Second, time series of demand would include the effect of technological change, economic conditions and consumer behaviour change. The capacity value estimated through several years would not be comparable, particularly if longer periods of time are considered. This is discussed in more detail in Appendix 5.

The five-year sample capacity value result shown in Figure 4, panels (a) and (b) may be a more reasonable estimate of the long-term contribution of intermittent resources to the adequacy of the system than individual year results. This five-year sample uses the whole time series of demand and output in the five-year year in a single run of the model. Studies have shown that use of several years of data, similar to the five-year sample run, can provide results that converge to long-term estimates of the capacity value of intermittent generators[72], which is also more consistent with the capacity valuation method performed for conventional generators.

[72] For example refer to B Hasche, A Keane & M O'Malley, 'Capacity Value of Wind Power, Calculation, and Data Requirements: the Irish Power System Case', in *IEEE Transactions on Power Systems*, vol. 26, 2011, 420–430.

For instance, the forced outage rate of conventional generators varies from year to year, however, the capacity value allocated to these resources is generally constant. The method for the allocation of capacity credits to scheduled generators uses long-term forced outage rates.[73] The Market Rules specify that scheduled generators receive capacity credits equal to their estimated sent-out capacity calculated at an air temperature of 41 degrees Celsius, unless their three year equivalent forced outage rate exceeds some thresholds specified in the Market Rules.[74]

For example, the coal-fired BW2_Bluewaters_G1 is a scheduled generation facility that has consistently received between 204 MW and 217 MW capacity credits since the capacity year 2008/09. This facility was on forced outage between 1 January 2017 and 18 July 2017, despite being expected to contribute to the reliability of the system by 217 MW in the capacity year 2016/17. The facility was on forced outage for a substantial portion of the hot season period. This is compared to the variation of the capacity value of intermittent generators. The maximum difference between the five-year capacity value result and annual results for intermittent generators is substantially less, at 71 MW.

The magnitude of the variation of the output of intermittent generators, however, is likely to increase as their penetration in the system increases. Intermittent generators' outputs vary by weather conditions and are correlated. The difference between the long-term five-year capacity value result and annual results can increase with rises in their installed capacity in the system. This can increase the forecasting inaccuracy of the relevant level method, if it only relied on the five-year result.

This forecasting inaccuracy does depend on the geographical dispersion of the installation of intermittent generation facilities in the SWIS. When many intermittent generation are installed in geographically disperse locations their output becomes more predictable and their combined output becomes less volatile when compared to their average output.[75]In contrast, the range of variation of the available capacity of scheduled generators is limited and generally does not grow as the number of these resources in the system increases. The available capacity of these resources is independent of each other.

[73] For instance, clause 4.11.1(h) of the Market Rules specifies thresholds for the outage rate of scheduled generators. AEMO can decide not to assign capacity credits, or assign a lesser quantity of capacity credits than their rated capacity at 41 degrees Celsius, to scheduled generation facilities that have had three year outage rates greater than the specified thresholds.

[74] Clause 4.11.1(h) of the Market Rules.

[75] This is due to the Law of Large Numbers which states that the sum of a large number of independent random processes becomes more predictable as the total number of processes increases.

Key Point

The ERA seeks feedback from stakeholders on how to calculate capacity value for the intermittent generator fleet. The capacity value of intermittent generators is expected to vary significantly from year to year due to changes in weather patterns. With increased penetration of intermittent generation in the system, this variation can become substantial and could create a significant risk in meeting the current reliability planning criterion of the SWIS.

The ERA considered several options for setting the capacity value of the fleet of intermittent generators, given the results of the sample model:

- The method could use the minimum of the annual capacity value results in the five-year period. For instance, based on the sample model results in Figure 4, panel (a), the fleet capacity value would be set at 180 MW. This option can better serve the reliability objective of the WEM, when compared to other options. However, the choice of minimum may underestimate the capacity value of intermittent generators. The system may procure more capacity than needed to meet the reliability planning criterion. This can increase the long-term cost of supply of electricity to consumers or result in economic inefficiency.
- The method could use the median of the annual capacity value results. For instance, the median of annual capacity value results in the sample model developed is 200 MW. When compared to average, median is not influenced by extremely large or small capacity value results.
- The method could use a trimmed average by excluding the largest capacity value result and estimating the average of the remaining four capacity values. For the sample model results, the trimmed average is approximately 206 MW. The use of a trimmed average can eliminate the influence of the largest capacity value result on the average. However, if annual results contain more than one extremely large value, the trimmed average would be biased towards the second largest capacity value result.
- The method could use the five-year sample result.

After receiving feedback from stakeholders, the ERA will make a decision about the choice of a suitable measure for setting fleet capacity value given expected volatility in the capacity contribution of intermittent resources.

6.2 Implementation considerations

The implementation of the numerical model would require a change of responsibilities under the Market Rules. Currently AEMO uses a formula and historical outcomes in the WEM to calculate capacity credits. The ERA develops models to provide AEMO with the constant parameters for the calculation. In effect the responsibility for the calculation of capacity credits is shared between these two parties. For the recommended numerical modelling, however, a single entity will be required to develop the model and conduct the calculation.

Any change from the current relevant level method to the proposed model should therefore specify the development of a numerical model, details of calculation and required input data. It should also specify the party responsible for the development of the model and, if required, a quality assurance mechanism.

In particular the implementation of the proposed method should remedy any deficiencies of the current relevant level method as implemented in the Market Rules. The current method does not fully explain the details of the calculation: it uses two constant parameters, K and U, whereas the Market Rules do not specify how these parameters should be determined.

The Market Rules place the responsibility for the determination of the value of K and U parameters on the ERA. The ERA could only refer to the previous reviews of the method to understand the reasoning for the application of K and U parameters and how their value have been determined in the past.

For the implementation of the proposed numerical model, the ERA used three assessment criteria:

- Transparency: the method should be transparent so that market participants and new entrants can assess their capacity contribution. The purpose and details of the method can be comprehensively explained to ensure transparency in the calculation of capacity values.
- Flexibility: the implementation should allow for some flexibility so that over time the model can be enhanced.
- Stability: the implementation of the method should consider the stability of the method. For instance, an overly prescriptive method may require frequent changes due to changes in the system or in interacting market rules. Frequent changes to the method would create volatility in the outcomes of the method.

The ERA assessed three options for the implementation of the proposed numerical model against the above criteria:

- detailed prescription in the Market Rules
- development of a detailed market procedure
- development of guidelines in the Market Rules

The first two options would provide transparency for the calculation and are likely to increase the stability of results. A detailed prescription of the method either in the Market Rules or a market procedure would entail detailed explanation of the calculation of effective load carrying capability of the fleet of intermittent resources, system adequacy assessment model, input data, and an allocation method. This would eliminate frequent changes to the method and therefore could enhance market participants' and new entrants' confidence in the calculation method.

The disadvantage of a detailed prescription of the method, however, is that it would not allow for flexibility in enhancing the method. This is particularly important when the model is first implemented, when the need for improvements to the model may become evident.. Changes in other market rules interacting with the relevant level method, such as the planning criterion, may also necessitate changes in the calculation.

For instance, in 2017 the California Public Utilities Commission used a numerical model to determine capacity values for intermittent generators. In its manual outlining the calculation of capacity values, the commission only provides guidance on developing the numerical model. For instance, the manual does not specify the type of adequacy model to be used, but it prescribes the use of a system adequacy model to assess the contribution of resources to the desired level of reliability. In its decision paper the commission stated:

> "At this initial implementation stage of ELCC [effective load carrying capability], it is too early to determine the ideal model to use, and we want to allow flexibility going forward to allow the most appropriate model to be used…Going forward, the process used to calculate monthly ELCC values will be subject to changes, improvements and refinements as needed."[76]

The third implementation option would provide the highest flexibility for enhancing the method over time. The Market Rules would only contain the purpose of the method and broad guidelines. For instance, the market rules may only specify that the calculation of the capacity value of intermittent resources is based on the effective load carrying capability. The entity responsible for the calculation of the capacity values would have flexibility to develop a system adequacy assessment model and determine the effective load carrying capability of resources.

The disadvantage of the third implementation options is that the details of the calculation would be opaque. Frequent changes to the calculation can also increase the volatility of results. Market participants and new entrants would have limited information to assess the number of capacity credits they receive and thus form a reasonable expectation of associated cash flows in the future. This can increase the cost of capital for funding investments in supply capacities in the SWIS.

The ERA recommends that guidelines would be included in the Market Rules as to how the model should be developed and what the model should deliver. This should be combined with a detailed specification of the model in a market procedure. This creates transparency and would help existing and potential intermittent generators make informed investment decisions. The implementation of the details of the model in a market procedure will allow enhancements to the model specification to be incorporated more flexibly and less costly than initiating a new rule change proposal.

If, following stakeholder feedback, the ERA recommends using a numerical model to calculate capacity values for intermittent generators, the ERA will propose a new rule change together with a market procedure for the implementation of the new relevant level method. The rule change proposal will follow the standard process established by the independent Rule Change Panel.

AEMO will undertake the calculation of capacity values as outlined in the market procedure to be developed. The ERA will review the method and the relevant market procedure at least once every three years and will consider the timing of the review of the planning criterion as discussed in section 5.5.1.

[76] California Public Utilites Commission, pp. 20–21.

The ERA will consider including transitional arrangements in the proposed rule change to dampen the financial impacts of changing the relevant level method. While the rule change and procedure are in development, the current relevant level method will apply. The ERA will publish unchanged values for the K and U parameters on its website.