Community Electricity

Response to ERA Public Consultation

Relevant level method review 2018

Capacity valuation for intermittent generators

Standing

Community Electricity is:

a a licensed Electricity Retailer** and provider of Electricity Retail Services & Market Consultancy;
b a member of the Market Advisory Committee for the previous 12 years; currently representing Market Customers, originally representing Market Generators;
c formerly a member of the Access Code Development Committee (2004)
d formerly a member of the Economic Regulation Authority's Technical Rules Committees from time to time;
e formerly the Chair of the Balancing & Ancillary Services Expert Team of the Market Rules Development Group (2004);

**** We announce that we are closing our retail licence and ceasing our pro bono publico contribution to the public consultations of the regulatory development of the electricity market.****

This is our penultimate contribution to the public consultation process. If you want to be informed of our free stuff from time to time, please email us.

Context

1. Community Electricity recognises the complexity and importance of the capacity certification of intermittent generators as outlined in the draft report.

2. We welcome the report's finding that the existing method is not fit-for-purpose and needs to be changed.

3. Insofar as it is appropriate to adhere to the current probabilistic paradigm, we support the ERA's proposal to adapt for the circumstances of the SWIS the recommendations of the Institute of Electrical and Electronics Engineers (IEEE) and the International Energy Agency Expert Group on Wind Integration Studies.

4. However, we observe that the review is coincident with a broad Electricity Market Reform and we suggest that the probabilistic paradigm should itself also be reviewed, whether or not this transcends the review's mandate.

Probabilistic paradigm

5. We consider that the current paradigm is epitomised by the report's references to the oxymoron of an "accurate estimate", which is alternatively mitigated in places to a "reasonable estimate".

6. According to the probabilistic paradigm, there is no merit in comparing the efficacy of candidate approaches by back-testing against actual historical outcomes.

7. Further, it seems that the ideal outcome hasn't even been defined. Rather, the paradigm assesses the efficacy of candidate alternatives by comparing their outcomes with each other, one of which is the actual certification but which has no claim to legitimacy beyond that.

8. Another feature of the probabilistic paradigm is the unstated assumption that there actually isn't a performance standard that the generator can target in order to maximise it's certified quantity and investment returns. And therefore, no means of valuing and monetising plant investments such as on-site batteries.

9. Instead, intermittent generators are subject to the fortune of however the system performs without it and the outcome of black box effective load carrying capacity calculations.

Define a Performance Standard

10. We would emphasise System Management's ethos that a power system can't be managed on the basis of averages or other long term statistical assessments.

11. We suggest that at as a point of beginning the review should ask, for example, on the mystical 1-in-10 year peak day:

    a What performance standard from the intermittent fleet does System Management actually desire?

    b On a 1-in-10 year peak day, would System Management be consoled by the fact that some of the fleet had performed well during winter evenings of the previous five years?

    c Would System Management be consoled by the fact that the fleet had performed well on the previous day, or even the hottest day of the previous year?

12. We further suggest that, insofar as the probabilistic paradigm is to be retained, each of the candidate approaches should be back-tested against the "System Management" standard.

13. We would also envisage that the "System Management Standard" would not be a straightforward specification. On the face of it, one might expect that the desire

would be for maximum output at the times of the load peak. However, we anticipate that there would be a caveat to the effect that the output of the intermittent fleet shouldn't impair the operation of the baseload fleet. Noting that the nameplate rating of the futuristic wind fleet is around 750MW relative to summer overnight load of, perhaps 2,000MW, a baseload fleet of 1,500MW and a peak of 4,000MW, there is scope for intermittent generators to crowd-out the baseload during its vulnerable operation at Min-Gen.

14. We would also ask a further question:

    Which parties should bear the risk of the intemittency of the capacity value of the intermittent fleet? Should it be the market or the intermittent generators themselves?

Suggested alternative paradigm

15. We suggest that as matters stand, intermittency risk is born by market customers paying for certified capacity that might not exist, and by intermittent generators that might be under-paid for the value they contribute. Or, more to the point, by both from time to time according to varying and unpredictable circumstances.

16. As matters stand, the Reserve Capacity Mechanism links supply and demand via the illustrative simplification:

Supply Side

Capacity Revenue = Certified Reserve Capacity x Capacity Price

Demand Side

Capacity Revenue = Capacity Price x TDL Ratio x Total Ratio x Excess Capacity Factor

17. We suggest that by equating supply and demand, this illustrative linkage can be reframed as:

    "Certainty" = Uncertainty" x Fudge Factor

    Where the supply side is well defined, or "certain" if everything performs to contract net of remedies for non performance, and the demand side is "uncertain" due to dependence on probabilistic factors such as weather, economic growth, customer behaviour and cultural artefacts (such as public holidays). The Fudge Factor is principally the Temperature Dependent Load Ratio, which corrects for forecast error.

18. As matters stand, the intermittent fleet is located on the "certainty" side of the balance. However, in contrast to scheduled generators, intermittent generators are required to meet lesser standards of performance and are largely exempt from

equivalent non-performance remedies. Intermittent generators are sanctified as "certain" through the certification process and insofar as they subsequently don't perform "optimally" from a market perspective, Market Customers bear the risk and the cost.

19. We suggest instead that the intermittent fleet should be relocated to the "uncertainty" side of the balance along the same lines as the TDL Ratio. We illustrate this through reference to Demand Side Management (DSM).

DSM and IRCR- turndown

20. DSM is located on the "certainty" side of the balance after having been sanctified according to its particular certification rituals, where it is paid the Capacity Price subject to its particular set of non-performance remedies. However, DSM has a sibling on the "uncertainty" side of the balance, called IRCR-turndown.

21. The 2018 ESOO summarises IRCR turndown over the previous 7 years, shown below, and demonstrates its variability.

4.1.4 Individual Reserve Capacity Requirement response

The RCM is funded through the IRCR mechanism, which requires AEMO to assign an IRCR to each Market Customer, based on the peak demand usage from its customer base in the previous Hot Season[79].

Specifically, the IRCR is a quantity (in MW) determined based on the median consumption of each metered load in a Market Customer's portfolio, during the 12 system peak intervals from the previous Hot Season. The IRCR is used to allocate the cost of Capacity Credits acquired through the RCM to Market Customers. As a result, the IRCR financially incentivises Market Customers to reduce their consumption during peak demand periods, and consequently to reduce their exposure to capacity payments.

The estimated reduction in peak demand associated with IRCR response since 2012 is shown in Table 10. There is no clear trend in the IRCR responses over the past seven years, with demand reductions varying from 41 MW to 77 MW and the number of customers responding between 20 and 59. The IRCR response on 13 March 2018 is the lowest to date at 41 MW, roughly the same as the IRCR response observed on 5 January 2015 (which was during a holiday period). The relatively low result for 2018 was largely due to the cooler than usual summer, which made predicting the timing of peak demand difficult for Market Customers.

Table 10 IRCR response on summer peak demand days, 2012 to 2018

Date	Daily peak demand (MW)	Time of peak demand	Estimated IRCR reduction (MW)	Number of customers responding
13 March 2018	3,616	17:30	41	36
21 December 2016 A	3,543	17:00	50	52
8 February 2016	4,004	17:30	77	57
5 January 2015	3,744	15:30	42	20
20 January 2014	3,702	17:30	50	44
12 February 2013	3,732	16:30	65	59
25 January 2012	3,857	16:30	50	59

A. The estimated IRCR response for the 2016-17 peak demand has been recalculated to reflect updated demand data (see Section 4.1.2 for further information).

The average IRCR response on peak demand days over the past seven years is 54 MW, with the highest response to date being 77 MW on 8 February 2016. This relatively high response corresponded to a predictable peak demand, which occurred following a succession of hot days that were accurately forecast ahead of time by BOM. Other IRCR Trading Intervals have been harder for Market Customers to predict, as they occurred at various times including December and March, resulting in lower IRCR response rates.

Over the past three years, 100 unique customers have responded, indicating that the IRCR mechanism encourages electricity users to reduce demand at peak times. Out of those unique customers, only seven responded on all three peak demand days, demonstrating that it is difficult to predict the IRCR intervals, or that there are other factors which affect a customer's ability to reduce demand.

22. IRCR-turndown is reported on annually in the ESOO and until last year was one of the "blocks" comprising the 10 year demand forecast. However, unlike DSM, it receives no formal capacity payment and is not required to perform under contract; it is governed only by the price signal and participant judgement as to how best to respond to circumstances; participants are free to turn down, load shift, switch on behind the meter generation, discharge a battery or whatever.

23. Whereas IRCR turndown's contribution has varied between 41 to 77MW and is assessed precisely retrospectively, DSM is certified at 66MW in advance.

24. Whereas DSM receives the capacity Price for performing to contract (basically turning down on demand, and usually not at all), IRCR turndown self-dispatches and if it times it correctly, avoids the cost of the Capacity Price uplifted by the TDL Ratio, or 1.5X as much as DSM. Correct timing requires the turndown to correspond to the definition of the system peak for the purposes of charging for certified capacity. However, if IRCR turndown misjudges the timing, a score of misjudged turndowns in a year count for nothing.

Utility-scale PV and Rooftop PV

25. We suggest that PV also represents a natural sibling relationship straddling the certainty-uncertainty balance. On the one hand, utility-scale PV is certified under the intermittent rules and after sanctification belongs on the "certainty" side, while rooftop PV manifests as a wildcard on the "uncertain" side in similar fashion to IRCR-turndown.

26. Whereas utility PV is certified and receives payments, the rooftop PV contribution is not expressly rewarded and is assessed in the ESOO as a component offsetting the target peak load.

27. We suggest that the review should enquire into harmonising the two. What are their differences? Which is preferred?

28. To demonstrate the standing of both styles, we again quote from the ESOO:

Figure 10 Methodology for the low, expected, and high scenario peak demand reduction from rooftop PV

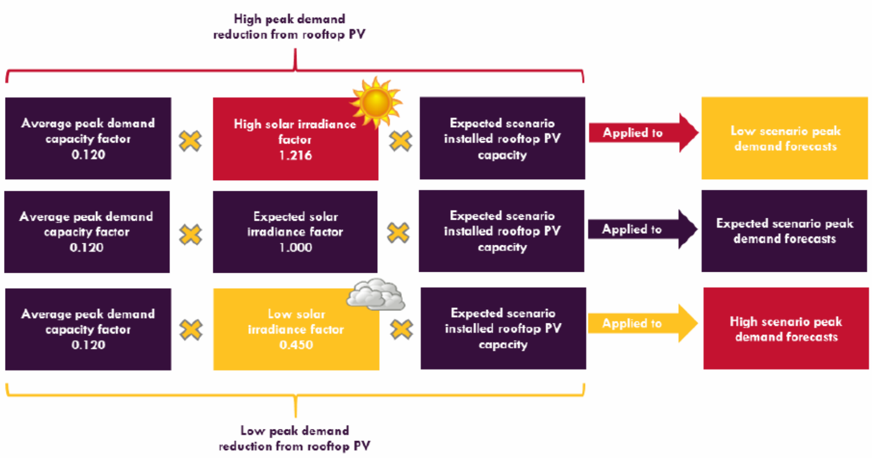
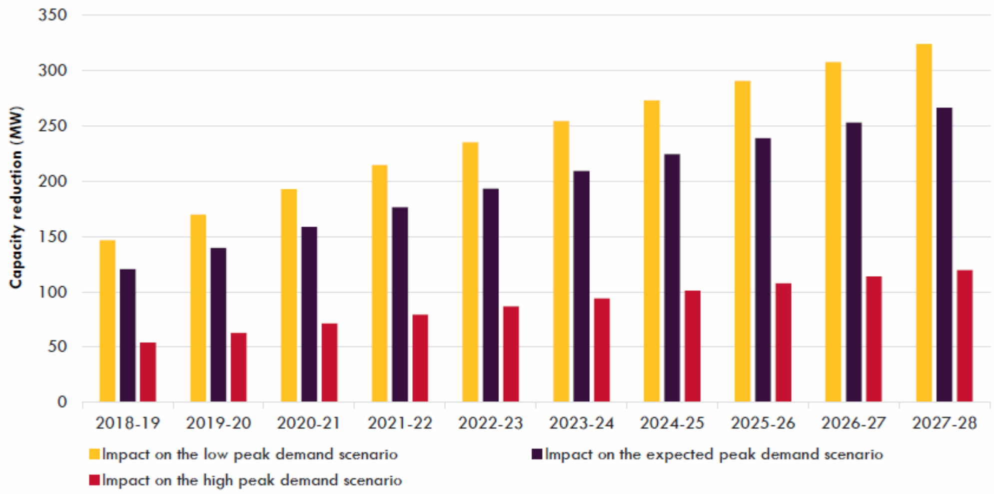


Figure 11 Peak demand reduction from rooftop PV systems, 2018-19 to 2027-28 A



A. The impact was calculated based on rooftop PV uptake forecasts in February under the expected growth scenario.
Source: AEMO and ACIL Allen.

Suggested alternative approach

29. On this basis, we suggest an alternative means of certifying intermittent generators might be as follows:

- Intermittent generator certified-capacity assessed retrospectively on the basis of the correspondence of its output with a specified performance standard that is visible and can be acted upon. For example, it might be output during the time of the system peaks, in similar principle to the valuation of IRCR turndown;

- Generators to be encouraged to incorporate storage into their developments to assist in meeting defined performance standards but at the generator's risk;

- Modify the "uncertainty" side of the balance to include an Intermittent Generator Fleet (IGF) Ratio;

- Integrate the IGF capacity contribution with the Reliability Criterion by means of a new forecast-block in determining the Reserve Capacity Target;

30. We suggest that this approach would continue to value the contribution of the intermittent fleet on an individual basis and generators would bear the consequences of "not performing".

31. Equally, intermittent generators would be rewarded according to their ingenuity in achieving the performance standard.

32. While we recognise that one of the benefits of locating intermittent generators on the "certain" side of the balance is the certainty of cash flows for underwriting financing, we suggest that it is a relatively small component of the whole, with the principal source being state subsidies. Equally, we suggest that intermittent-battery combined stations could radically change the demand (and price) profile of the power system because they would be used at all times of the year and not just at the peaks.

Contact

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