2020 review of two market rules intended to incentivise the availability of generators

Final report

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Executive summary

The Economic Regulation Authority has completed a review of two clauses of the market rules of the Wholesale Electricity Market that are intended to strengthen incentives for generators to have capacity available to the market; that is, to minimise planned and forced outages. The ERA conducted its reviews in consultation with the Australian Energy Market Operator (AEMO) and has assessed the operation of both clauses within the context of operation of the wider reserve capacity mechanism.

The two clauses of the market rules are:

- Reserve capacity reduction clause – this clause operates as a penalty mechanism by allowing AEMO to reduce the certified capacity of some generators if their outage rates have been above the threshold levels.[1]
- Refund Exempt Planned Outage (REPO) clause – this limits the number of planned outages that generators can take before they pay refunds for capacity that is unavailable.[2]

The reserve capacity reduction clause has been in place since market start in 2006. However, despite this clause it was observed in 2010 that four generators had planned outage rates above 40 per cent and were receiving full capacity payments despite being unavailable for large parts of the year.[3] To improve incentives for generators to make their capacity available a rule change was made in 2016 to strengthen the reserve capacity reduction clause and its outage thresholds, and introduce the REPO clause.[4]

The evidence is inconclusive on the effectiveness of the two clauses in improving generator availability.

- Although generator availability has increased in the WEM since 2010, there was no material change in generator availability after the clauses commenced in their current form.
- The increase in generator availability may alternatively be due to two generators with high planned outage rates exiting the market before the 2016 amendment of the reserve capacity reduction clause and the introduction of the REPO clause.
- Generation businesses have submitted that the incentives created by the two clauses are overshadowed by the normal commercial incentives to have capacity available to the market, and the clauses do not create any material additional incentive to make their generation facilities available.
- There have been no financial consequences for the few generators that breached the outage thresholds in the reserve capacity reduction clause.

1 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1(h)

2 Ibid. Rule 4.26.1C

3 The generators with large outage rates were: Kwinana G5 (53.6 per cent), Kwinana G6 (49.6 per cent), Pinjar GT11 (49.3 per cent) and Muja G7 (42.7 per cent) - Economic Regulation Authority, 2012, *2011 Annual Wholesale Electricity Market Report for the Minister for Energy*, p. 22, (online).

4 The REPO clause was part of the changes approved by the Minister in 2016 but did not commence operation until the 2017 capacity year.

The reserve capacity reduction clause

The value of the reserve capacity reduction clause is in the discretion of AEMO to assign capacity consistent with a generator's contribution to system reliability. The ERA has identified a broader concern with the operation of the clause within the reserve capacity mechanism. The capacity contribution of all generators after considering past levels of outages is important for assessing and maintaining system reliability. However, the clause allows AEMO to consider only the outages of generators above the outage thresholds when assigning capacity credits. This could result in over-estimation of the contribution to system reliability of the unassessed generators. Customers would then be paying for capacity and reliability that may not be delivered.

In each of the past five years, between two and five generators have had historical outage rates high enough to trigger application of the reserve capacity reduction clause. Despite this, AEMO has chosen not to reduce capacity credits for these generators. Instead, all generators have been assigned capacity credits based on AEMO's reasonable expectation of their output without accounting for the outage history.[5]

By limiting which generators can have their outages taken into account in assigning capacity credits, the clause may be resulting in AEMO over-estimating the expected capacity contribution of most generators to system reliability. As a result, AEMO may be procuring less capacity than necessary to meet the system reliability requirement. Although this has not been a problem to date while there has been a substantial excess of capacity in the market, over the next decade AEMO has forecast relatively small excess capacity quantities in the SWIS.[6] AEMO's decisions on how much capacity to assign for each generator to ensure system reliability have greater implications for system reliability as excess capacity reduces.[7]

The ERA considers that there may be market benefits from improving the operation of the clause by extending AEMO's discretion so that it can consider the historical outages of any or all generators when assigning reserve capacity, not just the few generators with outages above the threshold. This could be achieved by reducing the outage thresholds in the market rules to zero. While the clause will still operate as a penalty mechanism for those generators with excessive outages, implementation of the change will improve the tools that AEMO uses to determine a generator's capacity credits.

This change will mitigate the risk of AEMO under-procuring capacity and risking system reliability, or over-procuring capacity and increasing costs to consumers. This change will better support the market objectives of ensuring a reliable electricity supply and minimising long-term costs to consumers.[8]

The ERA will commence development of a rule change proposal to implement this change to the reserve capacity reduction clause. The ERA and AEMO have discussed implementation and AEMO is assessing the resourcing implications. At the request of AEMO, the ERA has commenced developing guidelines that would apply to the amended reserve capacity reduction clause.

5 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1(a)

6 AEMO, 2020, *2020 Electricity Statement of Opportunities,* pp. 4-5, (online).

7 Government of Western Australia, Public Utilities Office, 7 February 2019, *Improving Reserve Capacity pricing signals – a recommended capacity pricing model, Final recommendations report,* p. 51, (online). This report calculated the Value of Customer Reliability at $47,040 MWh.

8 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 1.2.1(d)

The Refund Exempt Planned Outage clause

The REPO clause makes generators liable for capacity refunds where the planned outage rate exceeds the specified limit.[9] AEMO assesses each generator's REPO count after every planned outage to determine if the generator breaches this limit. Over the past three years, four generators have had planned outages above the REPO count limit and incurred refunds.[10] The total refund payable from 2017 to date has been $1.3 million, or 0.07 per cent of capacity revenue for the generation fleet.[11]

The ERA considers that there are two significant deficiencies of the REPO clause.

- The REPO clause counts the total planned outage intervals incurred by generators. This count does not have regard to when the outage was taken and whether the outage may have affected a generator's contribution to the reliability of the system.
- The REPO clause includes only a single planned outage threshold, which does not recognise the different maintenance (and planned outage) needs of different generation technologies. The IMO initially set the REPO count limit based on the maintenance needs of coal plant.

Despite these deficiencies, the market rules limit the ERA's review of the REPO clause. The ERA can consider only changes to the REPO count limit and the duration of the calculation period.

The ERA considered either lowering or raising the REPO count limit. Lowering the limit to better account for the availability of other technologies, such as gas generation, may discourage coal generators from undertaking the maintenance needed to maintain their plant. This is inconsistent with the market objective for system reliability.[12] Alternatively, raising the limit would enable generators to take more planned outages before incurring refunds. This could allow generators with market power to physically withhold capacity from the market to increase electricity prices, which would be inconsistent with the market objective of encouraging competition.[13]

The ERA considers that no change to the REPO clause is warranted at this time.

9 The REPO count limit is a measurement of equivalent trading intervals that a generator is on planned outages, calculated over 1,000 trading days prior to the next planned outage of a generator. This includes partial planned outages. The REPO count limit is 8,400 trading intervals which equates to a 17.5% planned outage rate.

10 The four generators are Cockburn CCG1, Muja G5, Muja G6 and Pinjar GT9.

11 Refer to section 2.2. The refund is compared to total capacity revenue of scheduled generators only.

12 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 1.2.1(a)

13 Ibid, Rule 1.2.1(b)

1. Introduction

The ERA has reviewed two market rules (4.11.1(h) and 4.26.1C) that form part of the reserve capacity mechanism (RCM).This final report sets out the findings from the ERA's review of both clauses, and the ERA's conclusions on how one of the clauses should change to better achieve the WEM objectives.

For simplicity, the ERA refers to:

- market rule 4.11.1(h) as the reserve capacity reduction clause.
- market rule 4.26.1C as the Refund Exempt Planned Outage (REPO) clause.

The two clauses affect scheduled generators only, mostly coal and gas plants, that can increase or decrease the quantity of electricity generated in response to instructions from the system operator.[14] These facilities are referred to as generators in this report, unless stated otherwise.

1.1 Background and requirements of the two reviews

In capacity year 2010/11, four generators in the WEM had planned outage rates above 40 per cent.[15] These generators received full capacity payments even though they planned to be unavailable for extended periods, which meant that consumers were paying for a significant amount of unavailable capacity. In 2013, the IMO published a concept paper followed by a rule change proposal intended to increase the availability of generators.[16,17] In 2016, the Minister for Energy adopted these changes by amending the reserve capacity reduction clause and introducing the REPO clause into the market rules. These changes also included a requirement for the IMO to review the two clauses. This review responsibility was transferred to the ERA from the IMO in 2016 following changes to the institutional arrangements in the WEM.

The market rules require the ERA, in consultation with AEMO, to complete the reviews of the two clauses by 31 December 2020.[18] The ERA's role in conducting the reviews is to determine the effectiveness of each clause and consider changes that would better contribute to meeting the market objectives. Through the reviews, AEMO has focused on the functionality of the clauses and its obligation to ensure system security and reliability.

The ERA conducted both reviews together to reduce the cost of the reviews to the market and to facilitate stakeholder engagement. The ERA has also explored other matters it considered relevant to the reviews. These clauses have not been reviewed before and there is no obligation for the ERA to review the clauses again.

14 Wholesale Electricity Market Rules (WA), 7 August 2020, Chapter 11, Glossary.

15 Kwinana G5 (53.6 per cent), Kwinana G6 (49.6 per cent), Pinjar GT11 (49.3 per cent) and Muja G7 (42.7 per cent) - Economic Regulation Authority, 2012, *2011 Annual Wholesale Electricity Market Report for the Minister for Energy*, p. 22, (online).

16 Independent Market Operator, 2013, *CP_2013_01: Incentives to Improve Availability of Scheduled Generators*, (online).

17 Independent Market Operator, 24 March 2014, *RC_2013_09: Incentives to Improve Availability of Scheduled Generators* (online).

18 Wholesale Electricity Market Rules (WA), 7 August 2020, Rules 4.11.1E and 4.26.1D

1.1.1 Reserve capacity reduction clause

If a generator's historical forced outage rate (or combined planned and forced outage rate) is greater than the outage rate thresholds in clause 4.11.1D of the market rules, AEMO may reduce the reserve capacity assigned to that generator, subject to specific considerations. Therefore, AEMO can assign fewer capacity credits to a generator that is frequently unavailable due to its outages.

If AEMO assigns fewer capacity credits to a generator due to its outages, this will better reflect that generator's contribution to system reliability. Considering a generator's outage history when assigning capacity credits means that AEMO is less likely to overestimate capacity for that generator and risk under-procuring capacity in the SWIS to meet the reliability target. This enables the WEM to better meet the objective of promoting a reliable supply of electricity.[19] If AEMO accounts for outages when procuring capacity, customers pay only for capacity that is expected to be available, which helps the WEM meet the objective to minimise the long-term cost of electricity to consumers.[20]

The clause also supports the market objective of encouraging competition among generators and retailers in the SWIS by reducing incentives for market participants to retain inefficient and high-maintenance generators with poor availability and encourages generators to be available and participate in the balancing market.[21]

The ERA must review the operation of the reserve capacity reduction clause and the outage rate thresholds in the market rules.[22] The review must compare the availability of generators in the WEM with the availability of equivalent generators in other jurisdictions, calculate the number of generators that have breached the threshold rates, and consider the effect on the WEM of any decisions AEMO has made to reduce a generator's certified reserve capacity.

The review of the reserve capacity reduction clause is required under clause 4.11.1E of the market rules, and states that:

> The Economic Regulation Authority, in consultation with AEMO, must undertake a review, to be completed by 31 December 2020, of the operation of clause 4.11.1(h) in which it must consider the appropriate thresholds under clause 4.11.1D for Capacity Years from and including the 2022 Capacity Year. The review must include, at a minimum, an assessment of—
>
> (a) the availability performance of the generation sector in the Wholesale Electricity Market compared with analogous generating plants in other markets;
>
> (b) the number of Facilities in the SWIS to which the criteria in clause 4.11.1(h) have applied in each of the previous five Capacity Years; and
>
> (c) the impact on the Wholesale Electricity Market of decisions made by AEMO under clause 4.11.1(h) in the previous five Capacity Years.

The subject of the review, clause 4.11.1(h) in the market rules, states that:

> Subject to clauses 4.11.1B and 4.11.1C, AEMO may decide not to assign any Certified Reserve Capacity to a Facility, or to assign a lesser quantity of Certified Reserve Capacity to a Facility than it would otherwise assign in accordance with this clause 4.11.1, if—
>
> (i) the Facility has been in Commercial Operation for at least 36 months and has had a Forced Outage rate or a combined Planned Outage rate and Forced Outage rate greater

[19] Ibid, Rule 1.2.1(a)

[20] Ibid, Rule 1.2.1(d)

[21] Ibid, Rule 1.2.1(b)

[22] Ibid, Rule 4.11.1E

than the applicable percentage specified in the table in clause 4.11.1D, over the preceding 36 months; or

(ii) the Facility has been in Commercial Operation for less than 36 months, or is yet to commence Commercial Operation, and AEMO has cause to believe that over the first 36 months of Commercial Operation the Facility is likely to have a Forced Outage rate or a combined Planned Outage rate and Forced Outage rate greater than the applicable percentage specified in the table in clause 4.11.1D,

where the Planned Outage rate and the Forced Outage rate for a Facility for a period are calculated in accordance with the Power System Operation Procedure specified in clause 3.21.12.

Where AEMO makes a decision to reduce a generator's reserve capacity under clause 4.11.1(h), the market rules require AEMO to:

> Publish the reasons for a decision made under clause 4.11.1(h) on the Market Web Site to the extent those reasons do not contain any confidential information.[23]

When making a decision under clause 4.11.1(h), clauses 4.11.1B and 4.11.1C of the market rules stipulate that:

> In making a decision under clause 4.11.1(h) or 4.11.1(j), and without limiting the ways in which AEMO may inform itself in either case, AEMO may—
>
> (a) seek such additional information from the Market Participant that AEMO considers is relevant to the exercise of its discretion;
>
> (b) use information provided in reports related to the Facility submitted by—
>
> i. the Market Participant specified under clause 4.27.3; and
>
> ii. any other person under clause 4.27.6; and
>
> (c) consult with—
>
> i. System Management; and
>
> ii. any person AEMO considers suitably qualified to provide an opinion or information on issues relevant to the exercise of AEMO's discretion.[24]
>
> In making a decision under clause 4.11.1(h), AEMO—
>
> (a) must be satisfied that its decision under clause 4.11.1(h) would not, on balance, be contrary to the Wholesale Market Objectives;
>
> (b) may—
>
> i. consider the extent to which the Reserve Capacity that can be provided by the Facility is necessary to meet the Reserve Capacity Target;
>
> ii. consider whether the Reserve Capacity provided by the Facility is of material importance to the SWIS, having regard to—
>
> 1. the size of the Facility;
>
> 2. the operational characteristics of the Facility;
>
> 3. the extent to which the Facility contributes to the Power System Security or Power System Reliability through fuel diversity or location; and
>
> 4. the demonstrated reliability of the Facility;
>
> iii. assess the effectiveness of strategies undertaken by the applicant in the previous three years to reduce outages, and consider the likelihood that strategies

[23] Ibid, Rule 4.11.1A

[24] Ibid, Rule 4.11.1B

proposed by the applicant to maximise the availability of the Facility in the relevant Capacity Cycle will be effective;

iv. consider whether a decision to not assign Certified Reserve Capacity to the Facility is likely to result in a material decrease in competition in at least one market;

v. consider any positive or negative impacts on the long term price of electricity supplied to consumers that might arise if Certified Reserve Capacity was not assigned to the Facility; and

vi. consider any other matter AEMO determines to be relevant.[25]

1.1.2 REPO clause

The REPO clause places a limit on the number of planned outages that a generator can take before incurring reserve capacity refunds for subsequent planned outages. Introducing a limit on planned outages reduces incentives for market participants to retain inefficient and high maintenance generators with poor availability. This supports the WEM objective of promoting a reliable supply of electricity in the SWIS.[26] Retiring inefficient plant provides opportunities to invest in more efficient and reliable generators that can participate in the market. Incentivising existing generators to make their capacity available by limiting their planned outages supports the WEM objective of encouraging competition between generators and retailers in the SWIS.[27]

The REPO clause is one element of the capacity refund mechanism that determines when generators are subject to penalties or repayments as a result of their planned or forced outages. The REPO clause also supports the objectives of minimising the long-term costs of electricity to consumers and promoting competition in the WEM by requiring generators with excessive outage rates to repay capacity credits when their plant is unavailable.[28]

The ERA must consider whether there has been any change in forced and planned outage rates, generator participation in the RCM and the generation mix since the introduction of the REPO clause. The ERA must also calculate the number of planned maintenance hours that generators have incurred above the REPO count limit, and the value of the refund payable for these planned outage hours.[29]

The ERA can consider a change to the REPO count limit and to the time period over which the REPO count accumulates.

The review of the REPO clause is required under clause 4.26.1D of the market rules, which states that:

> The Economic Regulation Authority, in consultation with AEMO, must undertake a review, to be completed by 31 December 2020 of whether the limit for the Refund Exempt Planned Outage Count referred to in clause 4.26.1C should be modified to better address the Wholesale Market Objectives. The review must include, at a minimum, an assessment of—
>
> (a) variations in Planned Outage rates and Forced Outage rates of Scheduled Generators since the introduction of the limit on Refund Exempt Planned Outages;
>
> (b) for each Scheduled Generator and each year since the introduction of the limit on Refund Exempt Planned Outages

25 Ibid, Rule 4.11.1C

26 Ibid, Rule 1.2.1(a)

27 Ibid, Rule 1.2.1(b)

28 Ibid, Rule 1.2.1(d)

29 Ibid. Rule 4.26.1D

i. the number of Equivalent Planned Outage Hours for which Facility Reserve Capacity Deficit Refunds were payable; and

ii. the total amount of Facility Reserve Capacity Deficit Refunds associated with Refund Payable Planned Outages; and

(c) the level of participation by Scheduled Generators in the Reserve Capacity Mechanism in each year since the introduction of the limit on Refund Exempt Planned Outages; and

(d) changes in the mix of Scheduled Generators that have participated in the Reserve Capacity Mechanism in each year since the introduction of the limit on Refund Exempt Planned Outages.

If the Economic Regulation Authority recommends changes in the review in clause 4.26.1D, the Economic Regulation Authority must submit a Rule Change Proposal to implement those changes.[30]

1.2 Consultation

The ERA is required to undertake these reviews in consultation with AEMO. The ERA Secretariat has liaised with AEMO throughout the research, analysis and drafting process.

The ERA published an issues paper on 24 April 2020, seeking feedback on:[31]

- The operation of the two clauses and effects on market participants and the WEM.
- Whether the design and operation of these clauses achieves the intent of increasing the availability of generator capacity in the WEM.
- Other issues relevant to the market rules under review and future implications for the WEM.

The ERA received three submissions from Synergy, Perth Energy and Alinta Energy on the issues paper.[32] These submissions are addressed where relevant in this report and are summarised in Appendix 3.

The ERA published a draft report on 2 October 2020 and received submissions from Synergy and Alinta, both of which recommended retaining the current outage thresholds in the market rules. These submissions are summarised in Appendix 4. The ERA has addressed Synergy's and Alinta's feedback in section 3.3.

The State Government is undertaking a major reform program in the WEM. Before starting the review of these clauses, the ERA and Energy Policy WA discussed the scope of the ERA's reviews and the reform program and agreed that the reforms did not include the clauses under review by the ERA.

30 Ibid. Rule 4.26.1E

31 Economic Regulation Authority, '2020 Review of Incentives to Improve Availability of Generators – Issues Paper', (online).

32 Available on the ERA's website – Economic Regulation Authority, '2020 Review of Incentives to Improve Availability of Generators – Issues Paper', (online).

Since then, more reform initiatives have been finalised and shared with market participants, most notably the Network Access Quantities (NAQ) framework. This framework governs the allocation of capacity credits to generators after accounting for constraints on the network. Generators that continue to participate in the RCM and meet their performance obligations will maintain their NAQ. If a generator's performance falls, this puts its NAQ at risk. The NAQ that is lost due to poor performance could be assigned to a new generator entering the market.

The ERA supports the principle in the NAQ framework that generators that perform poorly surrender part or all of their NAQ. The ERA's conclusions are consistent with this NAQ principle and is discussed in section 4.1.1.

2. Review findings

The ERA has conducted the analysis required by the market rules (detailed in Appendix 5 and Appendix 6) to assess the operation of the reserve capacity reduction clause and the REPO clause. The figures in the final report include updates for the 2019 capacity year and finalised data that was unavailable at the time of the draft report.

2.1 Effectiveness of the reserve capacity reduction clause

AEMO can penalise generators by applying the reserve capacity reduction clause to generators with a forced outage rate greater than 10 per cent or a combined forced and planned outage rate greater than 20 per cent.[33]

Few generators breach the outage thresholds.[34] Over the past five capacity years, there have been between two and five generators in any year that have historical outage rates above the thresholds. The number of generators breaching the thresholds has not increased despite the thresholds gradually decreasing over time.[35]

When assigning capacity credits for generators with outage levels above the thresholds, AEMO assesses the likelihood of reoccurrence of the level of outages for the future capacity year.[36] If AEMO assesses an outage as explainable and unlikely to recur, it does not adjust a generator's capacity credits. Since the start of the market, neither AEMO nor its predecessor the IMO has reduced the capacity credits assigned to a generator using the reserve capacity reduction clause.

To assess any effect of the clause on the WEM, the ERA has considered how generator availability in the WEM has changed over time and how it compares with availability in other jurisdictions.

Annual average availability in the WEM has increased, from a low in 2010 when availability was 83 per cent, to 2019 when availability reached 91 per cent.[37] Two generators with high levels of planned outages left the market in 2014, which increased the average availability of the overall generator fleet.[38] There has been no obvious increase in the fleet's average availability after the reserve capacity reduction clause was amended in 2016.

Measured over the last 10 years, the WEM's generator fleet's average availability is 89 per cent. This is higher than the average availability of comparable generator units in the United Kingdom (83 per cent) and North America (80 per cent) but is below the availability of

33 Wholesale Electricity Market Rules (WA), 7 August 2020, Rules 4.11.1(h) and 4.11.1D

34 Appendix 5, Table 5.

35 The forced outage rate threshold has decreased by 1 per cent per capacity cycle from 15 per cent prior to the 2015 capacity cycle to 10 per cent from the 2019 capacity cycle onwards. Similarly, the combined planned outage rate and forced outage rate threshold has decreased by 2 per cent per capacity cycle from 30 per cent prior to the 2015 capacity cycle to 20 per cent from the 2019 capacity cycle onwards - Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1D

36 Although the assignment of capacity credits is a separate step in the RCM, the amount of reserve capacity certified to a generator ultimately determines a generator's capacity credit assignment.

37 Economic Regulation Authority, 2020, *Generator Availability Analysis*, Report prepared by GHD Advisory, p. 19. (online).

38 Generators Kwinana G5 and G6 with planned outage levels of 53.6 per cent and 49.6 per cent in the 2011 capacity year, stopped participating in the Reserve Capacity Mechanism after the 2014 capacity year.

the National Electricity Market's fossil fuel plants (94 per cent).[39] The mix of generator fuel source, age and type of generators varies between markets, which influences a fleet's availability. For example, the coal fleet in the United Kingdom is generally older and has largely been converted to use biomass as a fuel source.

Submissions from generators stated that normal commercial incentives to have capacity available to the market is a stronger incentive than the reserve capacity reduction clause. Alinta Energy acknowledged the "natural, and very strong, incentives to be available in a predominantly bilateral contract market."[40] Perth Energy agreed that, "while the incentives for generator availability in the WEM are important, they are not the primary driver, or even a major incentive for achieving high availability" compared to commercial incentives.[41] In addition, Alinta noted that not all generators received sufficient compensation from the capacity market alone to meet their fixed costs and so needed to provide energy to cover these costs.

2.1.1 Conclusion

The evidence is inconclusive as to whether the reserve capacity reduction clause effectively maintains or increases availability in the WEM. This is because:

- Few generators ever breach the outage thresholds and the system operator has never used the clause to reduce a generator's certified reserve capacity value.
- Availability in the WEM has increased over time and compares favourably with the availability of equivalent generators in other jurisdictions.
- There was no material change in generator availability following the amendment of the reserve capacity reduction clause.
- The submissions from market participants stated that the reserve capacity reduction clause is not a major incentive for greater generator availability.[42,43]
- The reserve capacity reduction clause is one of several mechanisms intended to incentivise generator availability in the WEM.

39 In its report for these reviews, GHD calculated fleet-wide availability factors based on the proportion of an operating period when the generator was available. These calculations take into account partial outages and are weighted by, in the WEM, a generator's capacity credit assignment for that capacity year, and by maximum installed capacity for other jurisdictions - Economic Regulation Authority, 2020, *Generator Availability Analysis*, Report prepared by GHD Advisory, p. 4. (online).

The comparable generator units in other markets are based on a generator's fuel type and installed capacity size.

40 Alinta Energy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 1, (online).

41 Perth Energy, 2020, Submission to, *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 1 (online).

42 Ibid.

43 Alinta Energy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 1, (online).

2.2 Effectiveness of the REPO clause

The current REPO count limit is 8,400 intervals of planned outages over 1,000 trading days and equates to a 17.5 per cent planned outage rate.[44] AEMO monitors each generator's REPO count as a rolling total of intervals of planned outages based on the 1,000 trading days prior to that generator's next planned outage.

Since the introduction of the REPO clause in 2017, four generators have had REPO counts above the limit in the market rules: Cockburn CCGT1, Muja G5, Muja G6 and Pinjar GT9. The total outages in excess of the REPO count was 723 hours in 2017, 43 hours in 2018 and 719.5 hours in 2019.[45]

In 2017, Cockburn incurred planned outage hours above the REPO limit and paid capacity refunds totalling $0.5 million, approximately 2.1 per cent of its capacity credit revenue.[46] In 2019, Muja G6 incurred the most planned outage hours across the SWIS (641 out of the 719.5 hours) and paid a refund of $0.7 million, approximately 2.8 per cent of its capacity credit revenue.

The total planned outage hours above the REPO count limit are equivalent to a total capacity refund of $1.3 million over the three years 2017 to 2019. The total refund is 0.07 per cent of the total capacity revenue for the generator fleet over the same three years.[47]

The ERA assessed whether there were material changes to forced outage rates and planned outage rates following the introduction of the REPO count limit at the start of the 2017 capacity year. For the period 2015 to 2019, the generator fleet's forced outage rates ranged from 0.8 per cent to 2.8 per cent, with planned outage rates ranging between 5.4 per cent and 7.4 per cent.[48] These observations show that neither the fleet's forced outage rates nor planned outage rates have materially changed or exhibited an apparent trend since the REPO clause was introduced. As only three full years have passed since the introduction of the REPO clause, the data is limited, and any longer-term effects cannot be determined at this time.

Some generators with high planned outage rates, identified in section 1.1, exited the market before the REPO clause was introduced. Overall, the planned outage rate has been trending downward since 2015 and continued to decrease after the REPO count limit was introduced but increased in 2019 due to more planned outages.

The introduction of the REPO clause was intended to place a limit on planned outages to reduce any incentive for market participants to retain inefficient plant with low availability. As part of this review, the ERA must analyse if and how the introduction of the clause has affected participation in the WEM.

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44 Assessed over 1,000 trading days prior to the next planned outage of a generator. The limit is a measurement of equivalent trading intervals as the calculation includes partial outages.

45 The planned outage hours referred to in this paragraph include partial planned outages in the calculation. The 2019 year is for a part year up to 31 August 2020. Full details are included in Appendix 6.

46 The $0.5 million was calculated based on the amount of reserve capacity refunds paid for all the planned outages that were above the REPO count limit.

47 This calculation only analysed scheduled generators and their associated capacity credits within the WEM. These figures differ from the draft report as updated and finalised figures have been included. See Appendix 6 for details and explanations.

48 These are the equal weighted fleet figures, with more details in appendix 6. The outage rates were calculated following AEMO's market procedure: AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

The total number of generators participating in the RCM has declined from 52 in capacity year 2013 to 38 in capacity year 2021. There has been no acceleration in the decline of generator participation in the WEM following the introduction of the REPO clause. The change in the number of generators between the 2017 and 2018 capacity years, from 48 to 39 generators, is mostly attributable to the retirement of 330 MW of generation by Synergy at the direction of the Minister for Energy. Since then, the number of generators participating in the WEM and the proportion of different generation by fuel type has remained fairly constant.[49]

2.2.1 Conclusion

The REPO clause has not been operating for very long and so there is limited data available to assess the effect, if any, that the clause has had on the WEM. In April 2020, only two facilities, Muja G5 and G6, had REPO counts above the limit. The next highest REPO count was Cockburn at 7,148 (refer to Figure 7 in Appendix 6). All other generators in the fleet were well below the limit. When a generator's planned outage is subject to refunds, it represents a small proportion of its total capacity credit revenue.

The ERA concludes that it is unlikely that the introduction of the REPO clause has affected generator availability in the WEM, but that data is limited and insufficient to draw any firm conclusions.

[49] Refer to Appendix 6, Tables 14 and 15.

3. ERA observations and conclusions

Before assessing options for each of the clauses under review, the ERA also considered the role they play within the RCM.[50] This is necessary to determine whether the clauses are still required and, if they are, to avoid proposing changes for either clause that have unintended consequences in other parts of the mechanism.

3.1 Role of clauses in the RCM

The reserve capacity reduction clause provides AEMO with a framework to consider how outages may reduce a generator's estimated capacity contribution. Without the clause, AEMO would be unable to assess whether a generator's estimated reserve capacity is consistent with its contribution to reliability in the SWIS. As a result, AEMO may assign too little or too much capacity to the generator.

Without the REPO clause, AEMO would lack the means to require generators to repay capacity funded but not provided due to planned outages over a given limit.

Both clauses are necessary but imperfect tools that assist AEMO to determine how much generators are paid for the capacity they make available.

3.2 Observations and conclusions for the reserve capacity reduction clause

The value of the reserve capacity reduction clause is in the discretion it provides AEMO to assign capacity consistent with a generator's contribution to system reliability. The ERA has identified a broader concern with the operation of the clause within the RCM. The ERA has made three observations on the reserve capacity reduction clause:

- The clause is not fully consistent with the planning criterion set out in the market rules.
- The clause risks double-counting the effect of outages on reserve capacity.
- When assigning capacity, AEMO lacks discretion both in how it can calculate outage rates and in how it takes outages into account when assigning capacity credits.

The ERA has reached the following conclusions for addressing the above observations:

1. No change is required to the operation of the reserve capacity reduction clause (clause 4.11.1(h)).[51]

2. A change is required to reduce the outage thresholds in the market rules to zero to allow AEMO the flexibility to assess any generator and its historical outages when determining that generator's certified reserve capacity.[52]

3. The development of guidance is necessary, as requested by AEMO, on how to apply the reserve capacity reduction clause.[53]

50 Appendix 7 outlines the assessment criteria applied to the clauses under review.

51 Discussed in section 2.1.

52 Discussed in section 3.2.1.

53 Detailed in Appendix 8.

3.2.1 The planning criterion

The planning criterion comprises a forecast of peak demand in the SWIS plus a reserve margin and allowances for intermittent loads, transmission losses and frequency control.[54] AEMO uses the planning criterion in the market rules to determine the quantity of capacity required to meet system adequacy, known as the reserve capacity target.

The reserve capacity reduction clause is partially consistent with the planning criterion as the clause enables AEMO, when assigning capacity credits, to consider the three elements that can affect a generator's availability: air temperature, forced outages and planned outages. The clause is inconsistent with the planning criterion because the market rules do not allow AEMO to consider outages for all generators, only those that breach the thresholds.

Unless AEMO is able to consider the historical outages of all generators, it is limited in its ability to certify capacity based on a generator's expected contribution to the reliability of the SWIS. By assessing only some generators, AEMO risks over-forecasting the capacity contribution of the generators that are not assessed. In this case, and as is the problem with the current approach, consumers pay for capacity that is expected to be delivered but is not because of forced outages.

The ERA has concluded that setting the outage thresholds to zero will remove this inconsistency.

This does not change how AEMO currently considers the effect of air temperature when determining the capacity of a generator based on its "reasonable expectation" of its output at 41 degrees Celsius.[55] With the outage thresholds in the market rules reduced to zero, AEMO could then consider the outage history of all generators when certifying reserve capacity.

Given the proposed change, AEMO would have flexibility to consider not only the total number of outages incurred by a generator, but also when the outages took place and how this affected the generator's contribution to the reliability of the SWIS. If AEMO considers that a generator's pattern of outages will continue in future capacity years, then it can acknowledge that the generator is likely to have a lower contribution to system reliability by assigning less reserve capacity.

The ERA did consider leaving the reserve capacity reduction clause and outage thresholds unchanged or reducing the thresholds to an amount above zero. The ERA does not support these options because of the restriction this would continue to place on AEMO when certifying reserve capacity. The excess capacity in the SWIS at present mitigates any risk of AEMO under-procuring capacity and so to date the WEM has met the market objective of providing a reliable supply of electricity. However, paying for large amounts of excess capacity does not support the objective of minimising the long-term cost of electricity to consumers.

[54] The description refers to the dominant planning criterion in the market rules and identifies the one-in-10 year forecast peak demand. The second part of the planning criterion is to limit expected energy shortfalls to 0.002 per cent of annual energy consumption - Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.5.9

[55] Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1(a)

AEMO may incur additional administration costs as a result of the proposed zero-threshold change. However, these additional costs must be compared to the possible benefits to consumers of AEMO assessing all generators' expected outages.[56] The ERA's preliminary analysis of the benefits to consumers is in Appendix 9. The detailed consideration of costs and benefits will be part of the rule change proposal development process.

3.2.1.1 Implications for generators - transparency

In its submission to the issues paper, Alinta supported a review of the factors AEMO uses to assess a generator under the reserve capacity reduction clause to empower AEMO to make objective decisions.[57] Alinta's submission to the draft report raised the risk that the proposed change to the thresholds could make the reserve capacity reduction clause more subjective and difficult to apply equitably over time.

The ERA's proposal to provide guidance to AEMO on how to apply the clause will make any decision to reduce reserve capacity more objective and transparent. The application of consistent, public principles to each decision and the ability for AEMO to assess all generators, not just those above the threshold, will improve decision making and market outcomes. The guidance described in Appendix 8 will complement the factors already in the market rules to provide greater transparency in how AEMO exercises its discretion.[58]

The ERA will continue to work with AEMO on how, in practice, it could apply the reserve capacity reduction clause as the ERA prepares a rule change proposal to implement its conclusions in this final report. Building flexibility into the guidance will be important to allow AEMO to use its discretion to disregard one-off and improbable events which are unlikely to affect a generator's future delivery of capacity.

3.2.1.2 Implications for generators – financial risk

The stakeholder submissions identified that the zero-outage rate threshold increased the likelihood of generators receiving fewer capacity credits during the reserve capacity certification process. However, generators with a low level of forced outages that contribute greatly to system adequacy, or plan to decrease the likelihood of future outages, would not be adversely affected by this change.

Synergy's submission to the draft report noted that the ERA's recommendation to reduce the outage rate threshold to zero may increase financial risk for generators from a loss of future capacity revenue resulting from a reduction to a generator's NAQ and its associated capacity credits. [59,60] This is discussed in section 4.1.1.

3.2.2 Double-counting outages

The reserve margin in the planning criterion assumes some level of outages at the generation fleet level. In the last review of the planning criterion, the IMO set the reserve margin at 7.6 per cent. This incorporated outage allowances of 11.6 per cent for coal generators,

56 Detailed in Appendix 9

57 Alinta Energy, 2020, Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 2, (online).

58 A list of considerations is stated in Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1C

59 Synergy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators – Draft Report*, pp. 2-3, (online).

60 Since the release of the draft report, the NAQ framework was finalised by the State Government - Energy Transformation Taskforce, 2020, *Assigning Capacity Credits in a Constrained Network – Network Access Quantity – Key Design Parameters Information Paper*.

10.9 per cent for gas and 16.2 per cent for dual fuel facilities.[61] The reserve margin is set as part of the review of the planning criterion, and between reviews AEMO has no discretion over the size of the margin or its application.[62]

The IMO set the outage thresholds in the market rules to gradually reduce each year from 2014 to settle, in 2019, at thresholds that are consistent with the maintenance needs of coal plant: 10 per cent forced outages, and 20 per cent combined planned and forced outages.

The IMO appears to have not considered the inter-relationship between the two outage allowances in either the review of the planning criterion or the market rule change process that proposed amending the reserve capacity reduction clause. The outage thresholds in the reserve capacity reduction clause are different to the outage allowances included in the reserve margin.

If AEMO were to use the reserve capacity reduction clause to reduce a generator's reserve capacity without considering the outage allowance already in the reserve margin, AEMO may be double-counting outages when procuring capacity credits. To date, this has not materialised as AEMO has not assigned a lesser value to a generator's certified reserve capacity through the reserve capacity reduction clause.

To avoid the risk of double-counting outages, a generator's certified reserve capacity needs to be adjusted only in proportion to its contribution to any gap between the outage level assumed in the reserve margin and the expected outages of the generation fleet.

AEMO has acknowledged the problem of double-counting outages identified by the ERA and is supportive of working with the ERA to resolve it.

3.2.3 Calculating outage rates

The facility outages market procedure determines how AEMO calculates historical forced and planned outage rates to determine which generators breach the outage thresholds in the market rules.[63]

In the market rules, outage rates are calculated over a fixed period of 36 months and are not based on a generator's actual operating hours. For example, a generator called to operate for five days within the prescribed 36-month calculation period that is on outage for four of those five days would have an outage rate of less than 0.5 per cent. However, if the calculation was based on actual operating hours, that generator would have an outage rate of 80 per cent.

The guidance that the ERA is developing on how AEMO applies the reserve capacity reduction clause includes options for how AEMO can calculate outage rates when determining a generator's reserve capacity. An outage rate calculated based on actual operating hours provides AEMO with a better indicator of the availability, or expected capacity contribution, of the generator when the system is under stress.[64] The benefits from using this outage rate calculation is provided in Appendix 9.

61 Market Reform, 2012, *Review of the Planning Criterion used within the South West Interconnected System* (online).

62 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.5.9

63 AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

64 Appendix 5 explains the difference between outage rate and outage factor.

3.2.4 Guidance to AEMO

During the review of the reserve capacity reduction clause, AEMO requested guidance on how to apply its discretion under this clause. Stakeholder submissions highlighted the need for an objective decision-making process to be published as guidance for AEMO to improve certainty for generators. This review found that guidance on the reserve capacity reduction clause would provide AEMO with tools to mitigate the risk of double-counting outages and to change how historical outage rates will be calculated and used.

The ERA agrees that there is a need for guidance to be developed and published. Appendix 8 sets out a method that AEMO can use when applying the reserve capacity reduction clause. The submissions by Synergy and Alinta Energy to the draft report raised concerns that the process to develop guidance for AEMO would not allow for stakeholder feedback and that the finalised guidance would not be made public.

Following publication of this report, the ERA will engage with the Market Advisory Committee in preparing a rule change proposal to implement the conclusions of this report. The rule change proposal will include guidance to AEMO on applying the reserve capacity reduction clause. This will allow stakeholders to comment on the contents of the rule change proposal before it is submitted to the Rule Change Panel.

3.3 Observations and conclusion for the REPO clause

The ERA has made three observations on the REPO clause:

- A single REPO count limit applies to all generators – a one-size-fits-all approach.
- The REPO clause does not consider when planned outages occur nor how the planned outage affects system reliability.
- There is a possible adverse effect from the REPO clause interacting with the reserve capacity reduction clause.

The market rules do not contain any method or information to guide the ERA on how to change the REPO count limit or the calculation period. The ERA could develop a method to guide a change in the REPO count if there was evidence to support such a change. However, as noted above and in section 2.2.1, there is insufficient data to draw a firm conclusion on whether the REPO clause incentivises availability. Despite these observations, the ERA considers that no change to the REPO clause is warranted at this time.

3.3.1 Single threshold

The REPO clause has a single outage threshold, equivalent to a planned outage rate of 17.5 per cent, that applies to every generator. Generators with planned outages above this limit pay refunds. The REPO count limit that underpins the outage threshold is based on the level of planned outages required for maintenance-intensive base load generators like coal plants.[65]

This approach does not recognise that different generation technologies require planned outages of different frequency and duration for maintenance. Setting the limit based on the maintenance needs of coal plants will have the likely result that other generation technologies

[65] Independent Market Operator, 24 March 2014, *RC_2013_09: Incentives to Improve Availability of Scheduled Generators – Final Rule Change Report*, pp. 20-21, (online).

are unlikely to ever breach the limit even if those generators were to have planned outage rates in excess of rates consistent with good operating practice for that technology type.

A series of REPO count limits to reflect the different maintenance needs of generation technologies may be appropriate. In its feedback to the issues paper, Synergy requested an exploration of separate REPO count limits by technology.[66] However, the market rules restrict the ERA's review of the REPO clause to reviewing only the REPO count limit and the duration over which REPO counts are calculated. Given these restrictions, Synergy's suggestion is outside the scope of the review.

Synergy also recommended an increase to the REPO count limit to allow generators to take planned outages during times of low system stress, reducing the likelihood of future forced outages.[67] The ERA considered increasing the REPO count limit so generators could incur more planned outages before breaching the threshold and having to pay refunds.[68] This would encourage generators to take the planned outages required to maintain their plants, reducing the likelihood of forced outages. Although unlikely, raising the REPO count limit could also mean that generators are available less often, which could put system reliability at risk. With the opportunity to take more planned outages, generators with market power may be able to physically withhold capacity and manipulate prices in the balancing market.[69]

Synergy stated that the physical withholding risk was mitigated by two clauses in the market rules that allow a market participant to apply for a planned outage in good faith only. When a market participant no longer intends to conduct a planned outage, it must withdraw that outage plan as soon as practicable. [70] Although these market rules assist in preventing generators physically withholding capacity, the REPO clause adds further financial disincentive to discourage the withholding of capacity. Also, since AEMO has no discretion on the application of the REPO clause, all generators are subject to the same limit and have similar disincentives to withhold capacity.

The ERA considers that increasing the REPO count limit would not assist in meeting the market objectives because so few generators breach the limit and there is a cost to consumers of paying for unavailable capacity. Although the REPO clause and the REPO count limit are arbitrary, there has been no observed significant adverse effects on the WEM from the introduction of the REPO clause.

Similarly, decreasing the thresholds would reduce the number of planned outages exempt from capacity credit refunds. More generators would breach the limit and more capacity refunds would be payable. However, given the current thresholds were based on the maintenance needs of coal plant, reducing the limit below the planned outage rate required by this technology would disproportionately affect coal generators by penalising them for taking necessary maintenance.

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66 Synergy, 2020 Submission to, *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, (online).

67 Synergy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators – Draft Report*, pp. 2-3, (online).

68 Raising the threshold to a very high level (such as 50,000 trading intervals) would effectively render the clause redundant and would be equivalent to removing the clause. No generators would breach the REPO count limit and no planned outages would be subject to capacity credit refunds. This option is unlikely to affect generator availability given the analysis in section 2.2. However, there is no directly observable link between the REPO clause and availability because there is only limited data available on the operation of the clause since it commenced. Removing the clause is not recommended on this basis and is out of scope.

69 This point was noted in the Economic Regulation Authority, 2011, *Annual Wholesale Electricity Market Report for the Minister for Energy*, pp. 21-24, (online).

70 Wholesale Electricity Market Rules (WA), 7 August 2020, Rules 3.18.7 and 3.18.8

3.3.2 Simple count of planned outage intervals

The REPO clause counts the number of intervals a generator was unavailable because of planned outages over a 1,000 day period. The simple count of intervals does not consider when the planned outage took place. Generators are required to pay refunds on the number of planned outage intervals above the REPO count limit and are not penalised for how those outages affect reliability in the SWIS. As with forced outages, planned outages that occur when there is ample excess capacity in the market have little effect upon the reliability of the system.[71]

The IMO set the REPO count limit after considering submissions received in response to the rule change proposal.[72] The 1,000 trading day calculation period was set based on limitations of the IMO's IT systems at the time.[73, 74]

In submissions to the issues paper, Synergy, Alinta and Perth Energy supported taking unlimited planned outages if those outages could be scheduled to not materially affect system reliability and stated that the existence of the REPO clause may lead to more forced outages.[75]

Allowing generators unlimited planned outages during periods of low system stress would mean that generators would avoid repaying capacity credits when the outage has no effect on the reliability of the SWIS. However, without specific REPO count limits for different generation technologies, generators could take more planned outage hours than necessary for maintenance. Customers would still be paying for capacity that was not available, even if the capacity was not needed at the time to support system reliability. This is inconsistent with the original intent of the REPO clause and does not support the market objective of minimising the long-term cost of electricity for consumers.[76]

Although the challenges with the REPO clause remain, planned outages will still need to be approved by AEMO. This process for approving planned outages limits the amount of generating capacity that can be on outage at the same time to prevent excess capacity in the system falling too low.

Synergy, Alinta and Perth Energy all suggested that generators may consider reducing or delaying their planned maintenance levels to avoid breaching the REPO count limit. However, Alinta submitted that, at the moment, the REPO count limit was "set at an appropriate level."[77]

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71 The outage planning process permits AEMO to not approve planned outages during times when it would threaten system security. This means that most planned outages are approved during times of ample excess capacity in the system.

72 Independent Market Operator, 24 March 2014, *RC_2013_09: Incentives to Improve Availability of Scheduled Generators – Final Rule Change Report*, (online), p 22.

73 Ibid, p. 20.

74 Perth Energy's submission noted that the 1,000 trading days period is arbitrary and is a round number of days but would equate to 2.74 year or 32.88 months, which is unlikely to reflect any better operating or maintenance pattern than the exiting 36-month timeframe used for the calculation of the outage rates for the purpose of clause 4.11.1D of the WEM Rules. Perth Energy, 2020, Submission to, *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 7 (online).

75 The three submissions are summarised in Appendix 3 and available on the ERA's website – Economic Regulation Authority, '2020 Review of Incentives to Improve Availability of Generators – Issues Paper', (online).

76 The original intent of the REPO clause was to put a limit on the number of planned outages that could be taken by generators as refunds were not paid on planned outages. By limiting the number of planned outages exempt from refunds, the REPO clause is an attempt to bring some equity between generators with high planned outage needs and generators that were available more often.

77 Alinta Energy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators*, p. 2, (online).

It is unlikely that generators would risk the failure of their plant by delaying their planned maintenance because of the REPO clause. As noted in section 3.3.1, most generators are well below the limit at any point in time.

3.3.3 Interaction with the reserve capacity reduction clause

If a generator has received fewer capacity credits because AEMO has applied the reserve capacity refund clause, then a refund triggered through the REPO clause may double count outages. However, this is true of a refund payable for a forced outage too and is a problem with the wider reserve capacity refund mechanism as outlined in chapter 4.

3.4 Conclusion

When making its determination on the changes required to address the challenges identified through the reviews, the ERA has sought to avoid adverse effects on the RCM, complement the Energy Transformation Strategy and consider the costs of change compared to the benefits.

Currently, the reserve capacity reduction clause risks AEMO over-estimating the expected capacity contribution of most generators to system reliability, when capacity credits are assigned. This is because the clause allows AEMO to consider only the outages of generators above the outage thresholds when assigning capacity credits. The ERA considers that there may be benefits to the market from improving the operation of the clause by extending AEMO's discretion so that it can consider the historical outages of any or all generators when assigning reserve capacity, not just the few generators with outages above the threshold. The ERA has concluded that this can be achieved by reducing the outage thresholds in the market rules to zero while providing guidance to AEMO on applying the amended reserve capacity reduction clause. This change will provide transparency to the market on how AEMO makes decisions under the clause.

4. Observations on the RCM

The market rules list several approaches for estimating capacity contributions for different types of capacity providers:

- 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 with the provision for a reduction to account for expected outages.[78]
- Intermittent generators, such as wind or solar farms, receive capacity credits based on the estimation method prescribed in the market rules – known as the relevant level method.[79]
- 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.[80]

The ERA has identified several challenges with the approach to estimating capacity contribution for scheduled generators. The conclusion in section 3.2, to reduce the outage thresholds to zero, will address some of these challenges. Separately, the ERA has reviewed the approach to certifying capacity for intermittent generators such as wind and solar farms and recommended an alternative approach.[81] Currently, the price of demand-side capacity is transitioning up to the same unit level as other forms of capacity and there is an open rule change proposal that may change how a demand-side capacity provider's contribution is calculated.[82]

In 2021, the State Government's Energy Transformation Strategy will change the market rules to allow capacity to be certified for storage technologies so that they can participate in the RCM, balancing market, short-term energy market and essential system services market. These changes will be tailored to the particular characteristics of storage facilities and how they could operate in the SWIS. The ERA has reviewed these proposed changes to the market rules but considers that they do not alter the analysis or conclusions in the report as both clauses under review primarily affect scheduled generators.

To be consistent with the planning criterion, generators, storage and demand-side management providers in the SWIS should be assigned capacity credits based on their contribution to the reliability of the system. This means that each megawatt of capacity is equivalent, regardless of it being delivered by different generation technologies, storage or demand side programs. Different approaches can lead to inconsistency in how capacity is valued for different technologies. This may not meet the market objective of avoiding discrimination in that market against particular energy options and technologies.[83]

The ERA has also identified a problem with the interaction between the reserve capacity reduction clause and the capacity refund mechanism. The problem arises because the

78 Wholesale Electricity Market Rules (WA), 7 August 2020, Rules 4.11.1(a) and 4.11.1(h)

79 Ibid. Rule 4.11.2(b)

80 Ibid. Rule 4.11.1(j)

81 Economic Regulation Authority, 2018, *Review of method used to assign capacity to intermittent generators 2018* (online).

82 Rule Change Panel, 2019, RC_2019_01 The Relevant Demand calculation, (online). As at December 2020, this rule change was still being developed.

83 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 1.2.1(c)

approach taken to measuring capacity at the time capacity is procured is different to how it is measured when refunds are calculated.

The provision of capacity is uncertain and varies with air temperature, forced outages and planned outages. The system operator needs to account for this variability when estimating a generator's future contribution to system adequacy and certifying reserve capacity. An example of this calculation for a theoretical generator is provided in the box below.

At the time of peak demand, a hypothetical generator has three possible available capacities (sent-out), c, with the probabilities, p, shown in Equation 1 below. For simplicity, this example assumes the available capacities are rated at 41 degree Celsius.

$$c = \begin{cases} 100\ MW, & p = 20\% \\ 50\ MW, & p = 40\% \\ 30\ MW, & p = 40\% \end{cases} \quad \text{Eq. 1}$$

The maximum rated available capacity of the generator at 41 degrees Celsius is 100 MW. The system operator understands that the generator cannot always produce 100 MW. The generator can provide 100 MW at the time of peak demand only 20 per cent of the time. Eighty per cent of the time, the available capacity of the generator is either 50 MW or 30 MW.

Given the uncertainty in the available capacity of the generator, the system operator will use a measure to estimate to what extent it can rely on the generator to meet the peak demand target of the system. The average available capacity of a thermal generator during periods of peak demand provides an approximate proxy for estimating its contribution to meet peak demand.[84,85]

The hypothetical generator's expected contribution to meeting peak demand, v, can be calculated as:

$$v = (100 \times 20\%) + (50 \times 40\%) + (30 \times 40\%) = 52\ MW$$

The market rules enable AEMO to account for the effects of air temperature and outages when assigning reserve capacity.

- First, the certified reserve capacity assigned to the generator must not exceed AEMO's reasonable expectation of the amount of capacity likely to be available from the generator at an ambient temperature of 41 degrees Celsius.[86]
- Second, the reserve capacity reduction clause allows AEMO to account for the effect of expected outages on the capacity contribution of the generator if the generator's historical outage factor exceeds the thresholds in the market rules.[87]

84 Stoft S., 2008, 'The Surprising Value of Wind Farms as Generating Capacity', *SSRN*, (online) [accessed 13 August 2020].

85 Thermal generators have available capacity distributions that are largely independent of each other and the distribution of demand in the system. In principle, when the number of thermal generators in the system is large, their expected capacity contribution is approximately their expected available capacity during periods of high reliability stress in the system, i.e. typically when demand is high.

86 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1(a)

87 For a new generator, the Market Rules require AEMO to base its decision on the expected outage factor of the facility over the first three years of operation. Otherwise for existing generators, the thresholds are in Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1D.

Assuming the hypothetical generator has an outage factor exceeding the thresholds specified in the market rules, AEMO could use its discretion in this clause to discount the certified reserve capacity of the generator to 52 MW, or some other value, to account for the effect of possible outages during periods of peak demand.[88]

After accounting for air temperature and outages, the capacity credits AEMO assigns will represent the expected contribution of the generators to meeting the reserve capacity target.[89]

To be consistent with the approach taken when capacity is procured, the calculation of refunds needs to be based on a generator's actual capacity contribution over the same period. In the WEM, this would be over a capacity year. An example of this calculation is provided in the box below.

For simplicity, this example assumes the capacity delivery period comprises four periods, t, only. During all periods t the amount of demand in the system is extremely high and air temperature is 41 degrees Celsius. The hypothetical generator's actual available capacity during the four periods is as below:

$$available\ capacity = \{t_1 = 100\ MW, t_2 = 100\ MW, t_3 = 50\ MW, t_4 = 30\ MW\}$$

The actual capacity contribution of the generator during the delivery period can be estimated as the average of the available capacity of the generator during the period:

$$v_{actual} = \frac{100 + 100 + 50 + 30}{4} = 70\ MW$$

In principle the generator would be liable for paying a refund of capacity credits based on the difference between its actual and expected capacity contribution. In this stylised example the generator over-performs its expected contribution (70 MW actual contribution, which is greater than 52 MW estimated expected contribution) and will not be liable for paying a refund. Other jurisdictions, such as the PJM Interconnection electricity system in the United States, pay a reward to over-performing generators, subject to conditions.[90]

In the WEM, the market rules require a generator to pay a refund when its available capacity falls below its assigned capacity credits in any trading interval when there is a forced outage or a planned outage above the REPO count limit. Therefore, the hypothetical generator would be liable for paying a refund during the periods t_3 and t_4, even though an allowance for outages had been applied when reserve capacity was assigned.

88 Assuming the generator is a new entrant to the market, AEMO would face a problem in estimating the expected outage rate of the facility as per the calculation specified in AEMO's market procedure for calculating facility outages. Currently the calculation of outage rates requires an estimate of assigned certified reserve capacity to the generator. But without exercising the effect of the clause 4.11.1(h), AEMO cannot form a view of what the amount of expected certified reserve capacity would be in the future. Currently it is not clear under the Market Rules if the hypothetical generator would have received 52 or 100 MW of capacity credits (either historically or as an expected value).

89 AEMO also accounts for other factor such as fuel supply and any other restrictions on the facility. AEMO assigns certified reserve capacity based on a generator's capacity at 41 degrees Celsius (assuming there are no limiting factors like fuel, etc). Capacity credits are then assigned up to the level of certified reserve capacity based on trade declarations. The NAQ process will factor in network constraints as well.

The reserve capacity target is determined by the planning criterion which is published by AEMO in its annual Electricity Statement of Opportunities document.

90 For example, refer to PJM, 2020, *PJM Manual 18, PJM Capacity Market, Revision: 45*, pp. 174–178, (online).

Generators will always have some level of outages. The current method for calculating refunds disproportionally penalises generators when expected outages have already been considered in the estimation of capacity credits. To be consistent with the planning criterion, refunds need to be calculated in proportion to the difference between a generator's expected and actual capacity contribution.

Through the review process, AEMO has requested guidance on how generators should be awarded capacity credits based on their contribution to system adequacy. AEMO has committed to working with the ERA to clarify how to exercise its discretion when assigning capacity credits. AEMO's primary concern is to meet the requirement of the planning criterion to ensure a secure and reliable supply of electricity in the SWIS, consistent with the market objective.

In the market rules, the refund mechanism determines the timing and quantity of payments from generators to AEMO as a result of planned and forced outages taken by the generator. This mechanism allows AEMO to obtain reserve capacity refunds when reserve capacity is not provided. The dynamic refund component penalises generators for outages during periods of system stress by requiring a repayment of up to six times the generator's capacity credits for those intervals.[91] The calculation of repayments required through the REPO clause may also inadvertently include double-counting for outages. The double-counting risk arises when a generator is required to make a repayment of capacity credits under the REPO clause but has already had its reserve capacity reduced by AEMO. This double-counting risk has not eventuated as AEMO has not used the reserve capacity reduction clause to reduce a generator's certified reserve capacity.

4.1.1 The NAQ framework

The NAQ framework is being implemented as part of the State Government's move to a constrained access market. As the NAQ framework uses inputs from the reserve capacity reduction clause, a reduction in certified reserve capacity from this clause would lead to a generator losing a corresponding amount of NAQ.[92] Once a generator loses NAQ, it is expected to be difficult to regain it, which consequently reduces the capacity credits that the generator will receive.[93]

Synergy's submission to the draft report notes the financial risk to a generator if its NAQ is reduced as a result of a decision under the reserve capacity reduction clause.[94] The financial risk to generators is a loss of future capacity revenue resulting from any reductions to a generator's NAQ and its associated capacity credits. While losing NAQ may increase the financial risk to individual generators, the overall system reliability risk in the market reduces. This is because reducing outage rate thresholds to zero will enhance AEMO's ability to ensure that there is sufficient electricity generation to meet demand and future energy needs. To inform an analysis of the costs and benefits of a reduction in the outage thresholds, the ERA has considered the value customers place on reliability, which is explored in Appendix 9.

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91 The dynamic refund mechanism is detailed in the Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1(c) and (d)

92 Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules – Explanatory Memorandum*, (online) [accessed 15 November 2020] and Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules*, (online) [accessed 15 November 2020].

93 Based on the latest version of the NAQ framework to date - Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules – Explanatory Memorandum*, (online) [accessed 15 November 2020] and Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules*, (online) [accessed 15 November 2020].

94 Synergy, 2020 Submission to *Economic Regulation Authority, 2020 Review of Incentives to Improve Availability of Generators – Draft Report*, pp. 2-3, (online).

The ERA's review has identified that the assignment of capacity credits to a generator needs to be determined consistently with that generator's contribution to system adequacy. This translates into lower capacity credits assigned to generators that provide a lower contribution because of a higher likelihood of forced outages. The NAQ framework similarly removes NAQ from underperforming generators. [95] Both the conclusions from this review and the NAQ framework are consistent in their treatment of generators with poor performance.

[95] Stated in section 1.2 of this report and in: Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules – Explanatory Memorandum*, (online) [accessed 15 November 2020] and Energy Transformation Implementation Unit, 2020, *Tranche 3 Amending Rules*, (online) [accessed 15 November 2020].

5. Next steps

In 2021, the ERA intends to introduce a rule change proposal to implement the changes to the reserve capacity reduction clause referred to in chapter 3. As required by the market rules, the ERA will consult with the Market Advisory Committee prior to making a formal submission into the rule change process.

Appendix 1 List of Tables

Appendix 2 List of Figures

Appendix 3 Stakeholder submissions to the Issues Paper

Three submissions were received from Alinta Energy (Alinta), Perth Energy and Synergy in response to the issues paper.[96] A summary of each submission is presented against the questions raised in the issues paper.

Table 1: Submission responses to questions in issues paper

Question	Submission Response		
	Perth Energy	**Alinta**	**Synergy**
AEMO (and the IMO previously) has not reduced the certified reserve capacity of a facility that had outage rates in excess of the outage thresholds specified in the Market Rules. 1. Considering the above, how do stakeholders view the efficacy and usefulness of this mechanism?	Generators have a commercial incentive to keep their plant in operation to generate energy and earn revenue. There is a requirement for an audit of generator's asset management system as part of the generator licensing regime. The ERA has pushed this assessment to the maximum period between audits of five years which indicates that the generation fleet is being well managed. When combined with there not being any significant loss of customer supply events due to outages, Perth Energy does not consider the mechanism necessary.	Alinta notes the following incentives of availability: • The mechanism in the Market Rules that allows AEMO to assign certified reserve capacity between zero and full allocation. • A 17.5 per cent equivalent planned outage rate as refund exempt planned outages. • Granting AEMO discretion to require a performance report and improvement reports with planned outages exceeding 1750 hours in the preceding 12 calendar months regardless of total system capacity availability. • Recycling refunds to generators based on dispatch.	AEMO's decision to not reduce certified reserve capacity of facilities that have exceeded outage thresholds does not deter from the efficacy and usefulness of the mechanism. AEMO's past decisions have effectively balanced the need to incentivise generator availability with maintaining system security. Analysis of historical data suggests that outage incidents for facilities which have breached thresholds are typically linked to large, one-off events that result in the facility not losing certified reserve capacity for future capacity years. AEMO's ability to discretely manage penalties is a necessary measure to balance qualitative aspects and consider the lifecycle of the plant.

[96] Available on the ERA's website – Economic Regulation Authority, '2020 Review of Incentives to Improve Availability of Generators – Issues Paper', (online).

				The rise in renewable generation has resulted in the current oversupply of capacity, which raises questions on the benefit of continuing this regime which was established to facilitate the avoidance of supply shortages. Given the environment of excess capacity, limits on planned outages are now less critical in the current state of the market and focus should instead be placed on minimising forced outage rates. Synergy considers that the existing forced and combined outage thresholds retains its usefulness in providing a target for Market Participants when conducting operational planning for outages.
2.	Do stakeholders consider that determining the availability of the generator fleet in the WEM in line with IEEE Standard 762 is appropriate for the ERA's review? What other approaches could be taken?	The IEEE Standard 762 is appropriate and the ERA should accurately apply the standard to all decisions on outages. The ERA has not accurately applied the IEEE Standard where: • A delayed response to Dispatch Instructions is treated as a full plant failure. • Ramping at less than the Dispatch Instruction ramping requirement as a partial plant failure. Accurately applying the IEE Standard gives a better indication of actual performance and is in line with international standards.	The IEEE Standard 762 is a standard measure in the northern hemisphere, the networks and systems are different from the SWIS in terms of scale, size, capacity and configuration and caution should be used when making comparisons.	No Comment.
3.	What level of outage rates and what factors do stakeholders consider should be	Generators should be encouraged to use the optimum level of scheduled maintenance time to minimise forced outages.	When reviewing availability incentives: • Consider the natural and strong incentives for generators to be available in a predominantly bilateral contract market.	Availability of a generation facility varies depending on the type of fuel, design of the facility, how the facility is operated/dispatched and the stage of its

used to assess the outage thresholds in 4.11.1D?	There should not be any outage threshold for scheduled maintenance. If outage thresholds continue, account should be given to the increased duty of other synchronous plant as Synergy's plants are retired and these plants take up their roles.	• The availability of a generator varies greatly depending on the type of fuel, design of the facility, how the facility is operated/dispatch and the stage in the lifecycle that the facility is at. • Ensure the regime does not have the perverse effect of generators not taking non-mandatory preventative and/or corrective maintenance which may lead to higher forced outages in the future. • Ensure that the incentives do not place undue regulatory risk and burden on participants which will lead to higher costs for generators that are passed on to end users.	lifecycle that the facility is at. These factors are: • Age of Facility – As the facility ages, an increase in planned outages would be anticipated. An excessively stringent outage threshold may result in the premature retirement of a facility. • Provision of ancillary services – Facilities which are subject to high levels of cycling due to the provision of ancillary services will incur higher levels of wear and tear, expediting the rate of deterioration. • Frequency of run vs facility type. • Market trends – The current generation mix is a significant departure from when the initial thresholds were set. Increased renewable penetration and the issue of the duck curve has led to heightened levels of cycling for generators which were originally designed to provide baseload generation. Increased maintenance and therefore increased planned outages are now typical occurrences for facilities that experience more breakdowns due to rapid load changes. This suggests that current outage thresholds are no longer appropriate. Synergy recommends that the level of outage rates be a uniform outage rate for all technologies and be amended to the following.

			• Combined planned outage and forced outage rate of 25 per cent. • Forced outage rate of 8 per cent. Generators need to take a certain level of planned outages to provide a reliable service when required. The current combined threshold only allows for a maximum of 10 per cent planned outages after accounting for a maximum forced outage rate of 10 per cent. This is insufficient to accommodate for major outages and an appropriate level of maintenance outages. If the combined planned and forced outage limit is increased to 25 per cent, the level of forced outages is expected to decrease thus the recommend reduction to 8 per cent (in line with NERC data). Synergy strongly recommends AEMO to continue exercising discretion in its application of penalties.
4. Is the possibility of breaching the outage thresholds a strong incentive to raise availability / retire the asset?	This is immaterial as an incentive and not a signal to retire an asset as the primary driver is the commercial incentive to generate and earn revenue. The only plant retirements and closures were at the direction of government than from economic signals.	See answers to questions 1 and 3.	Synergy considers that the incentive is strong for base load generators which have comparatively higher fixed costs but not necessarily for other technologies. A gas turbine that provides electricity for limited periods during the year will not be incentivised under the current mechanism to retire as they are unlikely to breach the thresholds. This is true for other technologies including Demand Side Management, Tesla batteries and renewable generators. Proportional to their run time, base load generators will require more planned outages for maintenance purposes and

			subject to more forced outages due to the constant cycling of the plant. The combination of high fixed costs, the risk of reduced certified capacity credits and foregone energy payments compound the need for market participants with base load generators to optimise the facility's availability.
5. Do the outage thresholds, and the possibility of AEMO exercising its discretion to reduce a facility's certified reserve capacity, strike an appropriate balance between signalling for generators to exit and motivating other generators to ensure an adequate level of availability?	These are immaterial as an incentive to raise generator reliability and are not a signal for retirement.	Alinta Energy considers that the current incentives (as a whole) seem appropriate to drive participant behaviour. Alinta questions whether the range of factors AEMO must consider when making a partial certification decision under clause 4.11.1(h) means that applying the rule is largely subjective and difficult to apply appropriately and equitably over time. Alinta recommends a review of these factors to ensure that AEMO is empowered to make objective decisions under this regime.	This provides a stronger incentive for market participants with base load generators to raise a generator's availability or retire the asset to maintain financial viability. Adverse behaviour may result if market participants reduce their planned outages to remain within the thresholds that risks incurring forced outages, which are not in line with the market objectives.
6. What are stakeholders' opinions on the one-size-fits-all approach of the outage thresholds in the Market Rules? If the incentives to increase availability are being met, how important should the composition of the	Recommends treating all synchronous plant with the same criteria as the gas fleet takes up the roles of peaking and stop-start cycling operations.	The effect from the refund exempt planned outage count on various facilities will vary greatly on the type of fuel a facility uses, the design of a facility, how a facility is operated/dispatched, and the stage of its lifecycle that a facility is at. The threshold needs to set an appropriate level of cover to all of these circumstances and ensure that no technology type is discriminated against.	The one-size-fits all approach to outage thresholds penalises base load generators that continuously provide electricity to the SWIS. In contrast, underperforming peak generation plants bear limited repercussions. The application of the existing outage limit mechanism has negligible effect on other technologies outside of base load generators which can be interpreted as a form of discrimination.

	WEM's generating fleet be in assessing the outage thresholds?		Alinta Energy supports retaining the "one size fits all" approach and that the current refund exempt planned outage count is set at the appropriate level.	Theoretically, outage thresholds should vary depending on the technology used however careful consideration would be required to determine the categories and associated thresholds.
7.	Should the reference technology for establishing the benchmark reserve capacity price be used to set the availability thresholds in the Market Rules? What are the benefits and problems of this approach?	The maintenance of a liquid fuelled open cycle gas turbine, the reference plant for the benchmark reserve capacity price, is not appropriate to use as it is only expected to run for a minimum period of time during the year and is atypical of most generating plant.	There are off-market incentives for the availability of generators with higher fixed costs than the theoretical 160 MW Open Cycle Gas Turbine used to determine the benchmark reserve capacity price. These facilities need to provide energy to cover their fixed costs. While removal of these facilities from the market due to planned outages may increase the energy market price, it is likely that they will have bilateral contracts which would require the purchase of energy to cover if they are on extended outages. Purchasing energy at possibly a higher cost than the generator could produce the energy at provides a strong commercial incentive to ensure facilities are available and providing energy.	Fundamental issues exist in using the reference technology for establishing the benchmark reserve capacity price to set the availability thresholds in the Market Rules. The outage limits are based on the attributes of a thermal generator. It would be difficult and inequitable to require market participants to meet the unavailability targets of a gas turbine which typically exhibits lower outage rates compared to existing thresholds stated in the Market Rules.
8.	Should the assessment for setting the BRCP also incorporate considerations for capacity availability and outage rates?	The danger of setting specific targets is that certain types of economical plant may be excluded as the range of different technologies, and their associated maintenance needs vary.	See answer to question 7.	See answer to question 7.
9.	Should there be a distinction between forced outage rates and planned outage rates as currently	Generators can only take scheduled maintenance subject to AEMO's approval and the availability incentives are for generators to perform their maintenance at times to avoid high capacity refunds.	No comment.	The distinction between forced outage rates and planned outage rates should be maintained as the effect of forced outages on system reliability is far more severe relative to planned outages.

	stated in the Market Rules? What are the implications of using a combined planned and forced outage rate threshold instead of the two separate outage threshold levels?	Due to the WEM's excess capacity, there is little requirement to limit scheduled maintenance beyond AEMO's operational requirements. The distinction between planned and forced outage rates should remain.		Reliance on a purely combined outage rate may inadvertently result in adverse behaviour as there wouldn't be an incentive to fix plant on scheduled planned outages. Increasing the flexibility around scheduled outages would not only promote economic efficiency through the reduction of forced outages, it would also reduce the long-term cost of supplying electricity.
10.	Do stakeholders consider that a facility's historical outage rates should be a material consideration for AEMO when setting certified reserve capacity for a future capacity year?	If a generator has received a satisfactory review of its asset management system as part of an independent audit required under the ERA's license review process, AEMO should not take into account a generator's historical outage rate as it gives AEMO a responsibility that it is not qualified to fulfil.	No comment.	No comment.
11.	What has been market participants' experiences of using a facility's prior 36-month forced and planned outage rate as a predictor of future generator availability?	Past performance gives a general/weak prediction of future performance however operations in the WEM are changing. For example, the Kwinana Swift generator has moved from super-peaking to a peaking/mid-merit role which has resulted in a different maintenance regime due to the increased number of stop-start cycles.	No comment.	No comment.
	Currently, the Market Rules seek to incentivise capacity availability by allowing AEMO to reduce a facility's certified	Availability is already strongly incentivised and once the RCM determines the amount and cost of reserve capacity, there is no	Alinta Energy broadly supports retaining the current availability incentives regime as it is, subject to a review of the range of factors AEMO must consider when making	Adoption of separate outage thresholds by technology type may assist in incentivising availability of generation capacity. However, the combined effects of existing mechanisms are sufficiently strong to

reserve capacity if that facility has breached the outage rates specified in the Market Rules. 12. What other mechanisms or incentives could be used to increase the availability of generation capacity?	commercial benefit to customers in driving availability to higher levels. The ERA may wish to consider reviewing the definition of availability.	a partial certification decision under clause 4.11.1(h).	promote increased availability for baseload and mid-merit generation facilities. These include: • REPO limits. • Outage thresholds. • Market reports – these present a significant administrative burden on a generator when required. • Other – natural incentives to be available in a predominantly bilateral contract market.
13. What are market participants' opinions on the REPO count limit of 8,400 and the associated calculation period of 1,000 trading days prior to a scheduled generator's planned outage? Is this limit and calculation period appropriate?	The 1,000 Trading Days is an arbitrary number and unlikely to reflect better operating or maintenance patterns than the existing 36-month timeframe used for clause 4.11.1D.	Imposing further limitation on the level of planned outages by reducing the refund exempt planned outage count may be detrimental to reliability standards in the SWIS. Some facilities may reduce current levels of maintenance to make sure they do not breach the planned outage cap which will likely affect the reliability of generators in the SWIS. There will be less opportunity for generators to undertake upgrades that may improve their overall performance.	If the existing outage limit thresholds are increased, the REPO count limit should be elevated accordingly. Synergy recommends that the ERA assesses whether AEMO discretion and separate REPO count limits by technology should be adopted.
14. What are the repercussions of the REPO count limit on scheduled generators in the WEM, particularly for operational and investment decisions?	There is a risk of generators that are close to their REPO limit that will restrict their scheduled maintenance to leave room. Cutting back on scheduled maintenance due to the REPO limit can perversely make generator reliability worse. The move to constrained network access may be relevant here.	See answer to question 13.	Although unlikely that a market participant would risk plant failure by failing to undertake necessary maintenance, the REPO count limit may incumber market participants from prudently scheduling planned outages at the most opportune times. Planned maintenance may be delayed to avoid breaching the REPO count limit or be inclined to compress maintenance within the shortest time rather than taking

			the required time to effectively conduct the outage.
15. What has been the experience of scheduled generators participating in the reserve capacity mechanism since the introduction of the REPO count limit? Has the REPO count limit had positive, detrimental or negligible effects on scheduled generator planned outage planning?	The REPO count limit has had negligible effects on planning of scheduled outages as Kwinana Swift, for example, requires two planned outages per year with a duration of between two to four weeks. The implementation of COVID-19 restrictions has extended the timeframe on some outages because of unforeseeable delays.	No comment.	See answer to question 14.
16. What are market participants' experiences of changes in the mix of scheduled generators within the WEM prior to and since the introduction (1 October 2017) of the REPO count limit?	Generation mix in the WEM has not been affected by the REPO count limit.	No comment.	No comment.

Appendix 4 Stakeholder submissions to the Draft Report

Alinta Energy and Synergy each provided a submission in response to the ERA's recommendations in the draft report.[97] Table 2 provides a summary of the issues raised by each submission against the recommendations from the submissions. Responses to these submissions are in section 3.3 of this report.

Table 2: Submissions to the draft report

Recommendation	Alinta Energy	Synergy
Retain the reserve capacity reduction clause and extend AEMO's discretion by setting outage thresholds to zero	Removing the threshold may • Undermine the objective of the RCM to incentivise investment capacity. • Increase uncertainty for generators as there is no benchmark on how certified reserve capacity will be determined. • Make the mechanism more subjective and difficult for AEMO to apply equitably over time.	This may have a negative effect on new investments in the WEM due to inadvertent interaction with the Network Access Quantity (NAQ) framework. All facilities with historical outages risk having reserve capacity credits reduced or removed when certified reserve capacity and the NAQ are determined. This introduces uncertainty when reserve capacity is certified and a generator's NAQ is calculated. This uncertainty may disincentivise new investment in the WEM. The existing clause should be retained. The issues raised will be better addressed by the ERA conducting a separate review of the entire mechanism to incentivise generator availability.
Provide additional guidance to AEMO on how to apply the reserve capacity reduction clause	AEMO should be supported to make more objective decisions under this clause. Alinta stated, "Given the importance of decisions to reduce certified reserve capacity on the financial viability of generation units, any guidelines on the application of the mechanism should be enshrined in market rules and/or procedures."[98]	AEMO should retain discretion in exercising the reserve capacity reduction clause due to the high level of technical complexity involved with analysing historical outages. The development of guidance notes should be subject to a formal consultation process. The zero threshold may increase the administrative burden for AEMO, reduce AEMO's capacity to assess generators requiring more comprehensive oversight and lead to erroneous decisions.

97 Available on the ERA's website – Economic Regulation Authority, '2020 Review of two market rules intended to incentivise the availability of generators – Draft Report', (online).

98 Alinta Energy, 2020 Submission to Economic Regulation Authority, *2020 Review of two market rules intended to incentivise generator availability – Draft Report*, p. 1, (online).

Retain the REPO clause unchanged	*No comment*	Prevailing measures render obsolete the risk of generators with market power taking more planned outages than necessary if the REPO count limit was raised. [99] The REPO clause may incentivise multiple faults being bundled into one large outage rather than addressed through prudent maintenance. Raising the REPO count limit would allow more planned outages and may improve generator availability when generation is most needed.

[99] The market rules referred to by Synergy are: Wholesale Electricity Market Rules (WA), 7 August 2020, Rules 3.18.7 and 3.18.8

Appendix 5 Minimum requirements for the reserve capacity reduction clause

The market rules set out the minimum requirements for the review of the reserve capacity reduction clause (4.11.1(h)).[100] These minimum requirements are part of the changes made to the reserve capacity reduction clause in 2016 and cover:

- The availability of the WEM generation fleet and how its availability compares to generators in other markets.
- Any decisions made to assign less reserve capacity to generators that had outage rates in excess of the thresholds in the market rules.

Each separate requirement is addressed under separate subsections within this Appendix.

As stated in the main body of the report, the two clauses affect only some generators, such as coal and gas plants, who are scheduled and dispatched by the market operator. These facilities are referred to as generators in the Appendix unless stated otherwise.

The explanation box below outlines the difference between outage rate and outage factor.

[100] Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1E

Generator outage rate, outage factor and capacity contribution

The capacity contribution of a generator is a function of the generator's probability of not being available (due to outages) when AEMO needs the generator to run. The forced outage rate stated in the market rules does not reliably measure the probability of outages when generators are required to generate electricity.

Despite the use of the term 'outage rate', the calculation of forced outage rate in the Market Rules is actually an 'outage factor', which is similar to the equivalent forced outage factor in the Institute of Electrical and Electronics Engineers (IEEE) Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.[101]

The forced outage rate in the market rules has two problems: it provides an unreliable estimate of the probability of outages and the application of this measure is inconsistent with the purpose of clause 4.11.1(h).

First, the calculation of forced outage rate under the market rules calculates outage ratios against the capacity credits of a generator. This does not provide a reliable estimate of the probability of outage, or the availability, of a generator. The calculation of an equivalent forced outage rate should be based on the maximum capacity of a generator.[102] This equivalent forced outage rate then provides a reliable estimate of the probability of outage during a year (but not necessarily during peak demand periods) and considers partial outages compared to the generator's maximum capacity.

Even if this first problem could be addressed to provide a more reliable estimate, another problem remains. Using an 'outage factor' as opposed to an 'outage rate' is inconsistent with the way capacity contribution is to be calculated during the capacity certification process. A generator's capacity contribution is dependent on the probability of outages during peak demand periods, which is better approximated by an equivalent outage rate rather than an equivalent outage factor.[103]

For example, some peaking generators are called to operate for only a few hours during a year and report only a few outages throughout that year. They typically have a very low equivalent forced outage factor (or 'forced outage rate' in the market rules). If these generators frequently fail to operate when AEMO requires them, they would have a high probability of outage when they are needed and thus, would have a low capacity contribution. Thus, the calculation of outage rates as per the current market rules under-represents the probability of outages during peak demand periods for some generators.

101 IEEE, 2007, *IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, New York, USA.

102 Generators have several levels of outage from zero to their maximum capacity. In practice it is not feasible or necessary to accommodate many outage levels and the probabilities for each outage level. In practice, the number of outage levels is reduced to two: up state with maximum capacity and down state with zero capacity. All other outage states are weighted into these two states to calculate an equivalent outage factor or rate. Billinton R. and Allan R., 1996, *Reliability evaluation of power systems, second edition*, Plenum Press, New York, p. 46.

103 Service hours are the number of hours that a generator is required to generate electricity within a given period.

The availability performance of the WEM's generation sector compared to other markets[104]

To address this requirement, the ERA engaged a consultant, GHD Advisory to:

- Assist in gathering generator availability data.
- Align the data with the Institute of Electrical and Electronics Engineers (IEEE) Standard 762 to enhance comparability.

GHD compared the WEM generator fleet to the equivalent fleets in the National Electricity Market (NEM), the United Kingdom (UK) and the North American market, through North American Electric Reliability Corporation (NERC) data.

Definitions and terms for availability and the assessment

Although the market rules use the term facility, only generators in the WEM were assessed because: [105]

- Distribution systems, transmission systems and loads do not receive capacity credits.
- Demand side programs do not log outages.
- Non-scheduled generators, such as wind and solar farms, have no outages for the purposes of the RCM outage calculations.[106]

104 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1E(a)

105 A facility is defined in Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 2.29.1

106 The market rules state that the quantity of reserve capacity that a non-scheduled generator needs to have available for a trading interval is zero. As there is no reserve capacity required to be available, any outages are also recorded as zero for the purposes of the RCM calculations - Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.12.4(aA)

Explanation – Availability factors

GHD Advisory calculated availability factors to compare generator availability. An 'availability factor' is calculated and is defined as a "fraction of a given operating period in which a generating unit is available without any outages".[107] For example, a generator that has three months on outages over a twelve month period would have an availability factor of 75 per cent.

An equivalent availability factor accounts for partial outages. For example, a generator with 100 MW of capacity that has a 50 MW forced outage for a trading interval would be measured as having 50 per cent equivalent availability for that trading interval. This is consistent with AEMO's Power System Operating Procedure method for calculating facility outage rates.[108]

Availability factor can be a satisfactory measure of a generator's probability of outage, or probability of availability, when the generator is frequently called to generate electricity. The frequent operation and its availability status during those operation periods provides a reasonable estimate of the probability of capacity availability during periods the generator is called to operate.

However, when a generator is seldom called to generate electricity, its availability factor cannot provide a reliable estimate of its availability probability during periods the system operator calls on the generator to produce. These generators often do not operate and are less likely to incur forced outages accordingly. Estimating the probability of availability of a generator during in-demand periods, requires the application of availability outage rates similar to that used in PJM (refer to discussion in section 3.2).

For example, the coal/gas fleet started the 2009 capacity year with a low availability factor of 60 per cent and increased to 90 per cent prior to retirement in the 2014 capacity year. Although this was an improvement in availability factor, the reality was that the coal/gas fleet was being called upon for less and less generating hours in the year to generate. Thus, there was less chance for the generator to fail and less hours that the generator may have been on forced outages, which made the availability factor rise accordingly.

Results of international comparison

The GHD Advisory report contains the results of the international comparisons.[109] GHD Advisory compared individual WEM generators to:

- UK fossil fuel thermal units.
- NEM fossil fuel plants.
- NERC fossil fuel thermal plants that were producing less than 300 MW.

[107] The Institute of Electrical and Electronics Engineers [IEEE] 2016, *IEEE Standard 762-2016 IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, (online) [accessed 19 March 2020].

[108] AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

[109] Economic Regulation Authority, 2020, *Generator Availability Analysis*, Report prepared by GHD Advisory, p. 4. (online).

- WEM scheduled generator fleet.[110]

Table 3 compares the availability of the fleets in the different market or region.[111]

Table 3: Availability factors for generators in the WEM and in other comparable markets and regions

Market/Region	Availability factor (per cent)
NEM fossil fuel plants	94
WEM generator fleet	**89**
UK fossil fuel thermal units	83
NERC fossil thermal plant units < 300 MW	80

Source: GHD Advisory 2020

The WEM's generator fleet has a higher level of availability relative to comparable units in the UK and North America but is below the availability of the NEM's fossil fuel plant. The mix of generator fuel source, age and type of generators varies between markets which influences a fleet's availability factor. For example, the UK coal fleet is generally older and has substantively been converted to using biomass as a fuel source. Further details on the individual fleets used for comparison are detailed in GHD Advisory's report.[112]

Number of facilities to which the reserve capacity reduction clause could have been applied[113]

Before AEMO can apply the reserve capacity reduction clause, the generator has to breach the outage thresholds in Market Rule 4.11.1D. AEMO calculates a generator's outage rate based upon the planned and forced outages, including partial outages, over the previous 36-month period.[114]

110 The WEM generator fleet figure is a weighted equivalent availability factor aggregated measure. It is weighted based on a generator's level of capacity credits and 'equivalent' as it includes partial outage events.

111 The WEM's availability factor is based on a 10-year factor; the UK on a 5-year factor and both the NERC and NEM on a 3-year factor due to different data availability between the regions.

112 Economic Regulation Authority, 2020, *Generator Availability Analysis*, Report prepared by GHD Advisory, pp. 19-31. (online).

113 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1E(b)

114 The calculation is contained in: AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

Table 4: Outage rate limit table in the Market Rules (%)

AEMO decisions for the capacity cycle	Forced outage rate percentage greater than	Combined planned outage rate and forced outage rate percentage greater than
Prior to 2015	15	30
2015	14	28
2016	13	26
2017	12	24
2018	11	22
2019 onwards	10	20

Source: Clause 4.11.1D of the Market Rules

In its review, the ERA must report on the number of generators, in the previous five capacity years, which breached the outage thresholds and could have had their reserve capacity adjusted through the reserve capacity reduction clause.

This is to determine if more generators are breaching the thresholds given the outage rate thresholds reduced incrementally for each capacity cycle from 2015. Table 5 shows the number of theses applicable generators over the assessment period.

Table 5: Number of applicable facilities that the reserve capacity reduction clause could have applied to

	2015	2016	2017	2018	2019
Number of applicable facilities	5	2	2	2	3

Source: ERA and AEMO analysis of market data

Generators with an outage rate above the thresholds do not automatically have less reserve capacity assigned as any reduction is at AEMO's discretion. AEMO assesses the likelihood of reoccurrence of the level of outages for the future capacity year. Explainable outage events that occur rarely are unlikely to result in any adjustment to a generator's reserve capacity if AEMO is satisfied that it will not reoccur. Since the start of the market, neither AEMO nor the IMO have reduced the level of reserve capacity assigned to a generator using the reserve capacity reduction clause.

Effect on the WEM of decisions made by AEMO under the reserve capacity reduction clause[115]

By not using the reserve capacity reduction clause, AEMO has certified each generator's reserve capacity consistent with its reasonable expectation of the generator's capacity when operating at 41 degrees Celsius.[116] As there have been no reductions to reserve capacity through AEMO's consideration of this clause, the ERA cannot assess that effect on the WEM.

Instead, the ERA has conducted a comparative analysis to identify whether historical outage rates, used by AEMO to inform its assessment of expected outages when certifying reserve capacity, are representative of a generator's actual outage rates. [117,118]

Comparative analysis

The ERA assessed the most recent five capacity years to see how generators' actual performance compared to an estimated forecast. The estimated forecast is based on 36-months of historical outages. [119,120,121]

Table 6: Comparative analysis of total planned and forced outages rates for the WEM generator fleet

Total Planned and Forced Outages	2015	2016	2017	2018	2019
Expected	11.1%	10.1%	9.9%	10.5%	4.3%
Actual	11.2%	11.6%	4.6%	4.4%	5.9%
Difference	0.1%	1.5%	(5.3%)	(6.1%)	1.5%

Source: ERA analysis of market data

115 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.11.1E(c)

116 Ibid Rule 4.11.1(a)

117 Using the method prescribed in: AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

118 Each scheduled generator was calculated individually with a fleet aggregated figure derived by weighting on the proportion of capacity credits a scheduled generator received for that capacity year relative to the scheduled generator fleet's total capacity credits for that same capacity year.

119 The 2019 capacity year difference figure differs is due to rounding.

120 This method is consistent with AEMO's procedure for calculating outages: AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

121 Since the assessment for a capacity year is completed two years prior to the actual capacity year, the forecast does not incorporate outage information for a generator for those intervening years.

Table 7: Comparative analysis of forced outage rates for the WEM generator fleet

Forced outages	2015	2016	2017	2018	2019
Expected	2.8%	1.7%	1.5%	1.6%	2.2%
Actual	0.9%	3.3%	0.7%	1.2%	1.4%
Difference	(1.9%)	1.6%	(0.8%)	(0.4%)	(0.8%)

Source: ERA analysis of market data

Table 8: Comparative analysis of planned outage rates for the WEM generator fleet

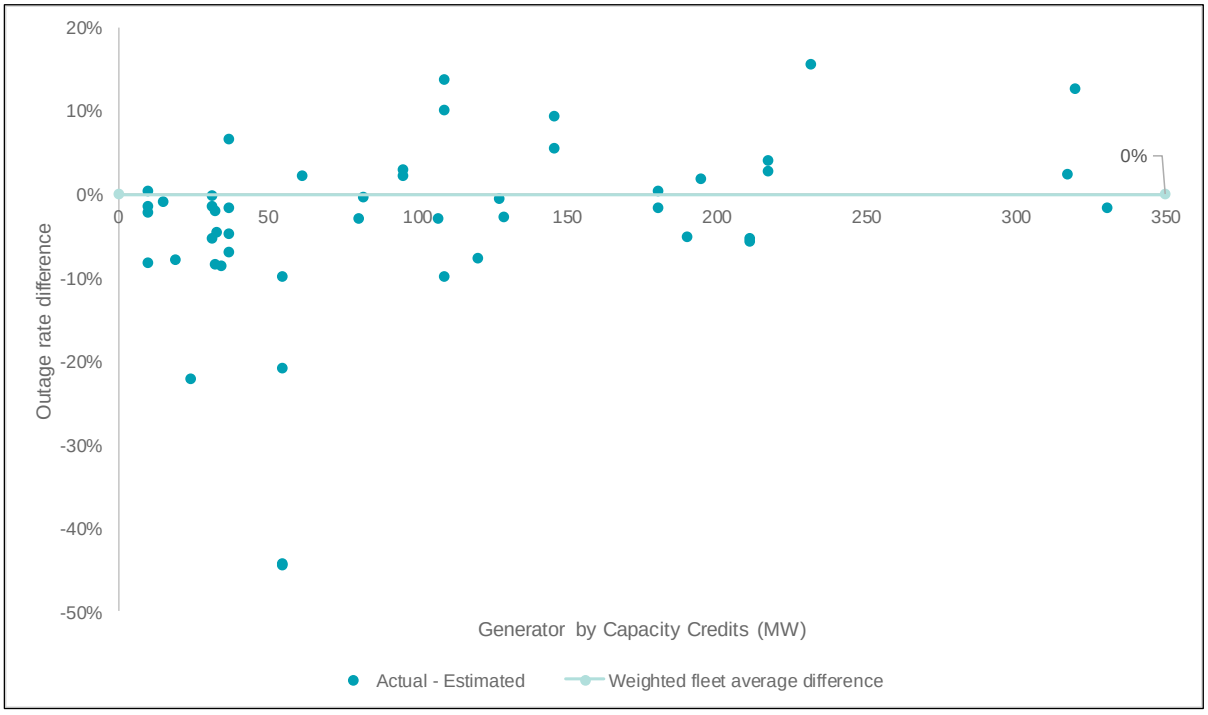
Planned outages	2015	2016	2017	2018	2019
Expected	8.3%	8.4%	8.4%	8.9%	2.2%
Actual	10.3%	8.3%	3.9%	3.2%	4.5%
Difference	2.0%	(0.1%)	(4.5%)	(5.7%)	2.3%

Source: ERA analysis of market data

From the comparative analysis, the variations in forced outages of the fleet do not vary significantly between expected and actual with most years recording forced outages lower than expected. In capacity years 2017 and 2018, the total forecast forced and planned outage rates for the generator fleet (Table 6) were in excess of the actual performance fleet outage rate by a significant margin. This was mostly due to an overestimation of planned outages (Table 8). An explanation for this is that outages that were caught in the historical estimate did not reoccur to the same extent during the actual capacity year as each generator has different maintenance requirements depending on where it is in its lifecycle.

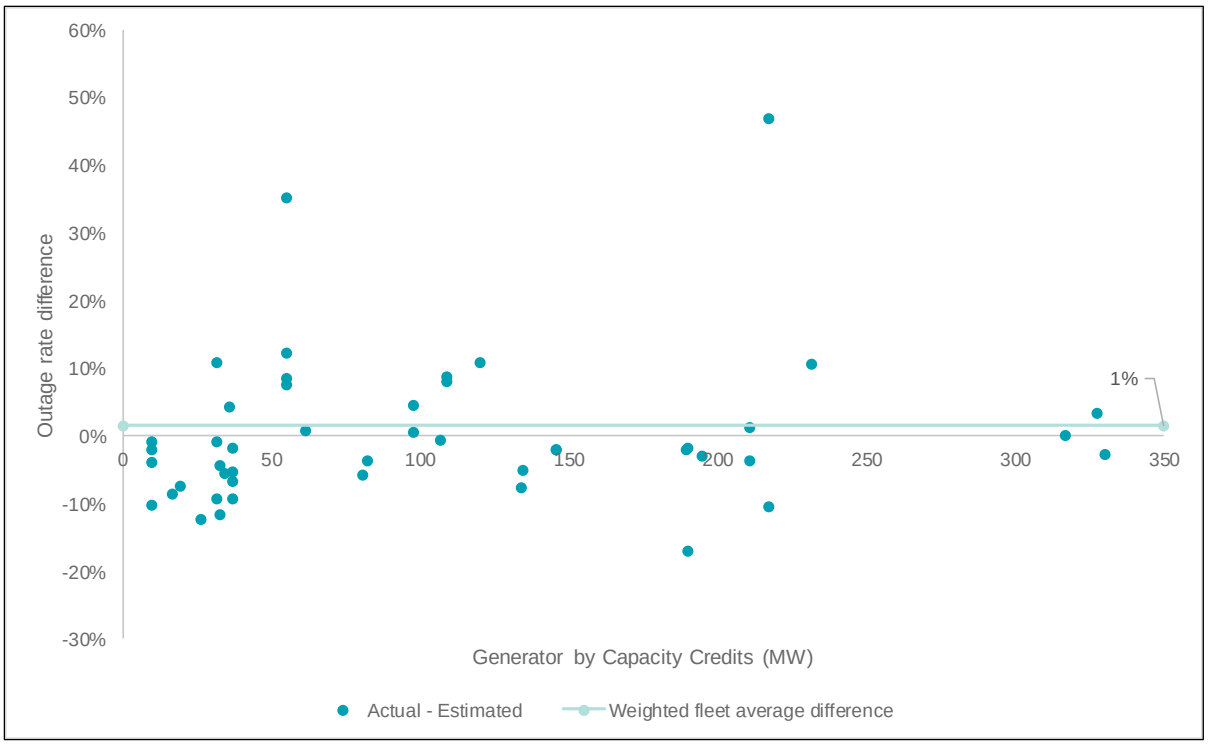
Figures 1 to 5 show the difference between expected and actual outages for each generator in the WEM, which was used to determine a WEM fleet outage difference figure. Analysis was conducted using each individual generator's planned and forced outage data.

Figure 1: Difference in outages for 2015 by generator



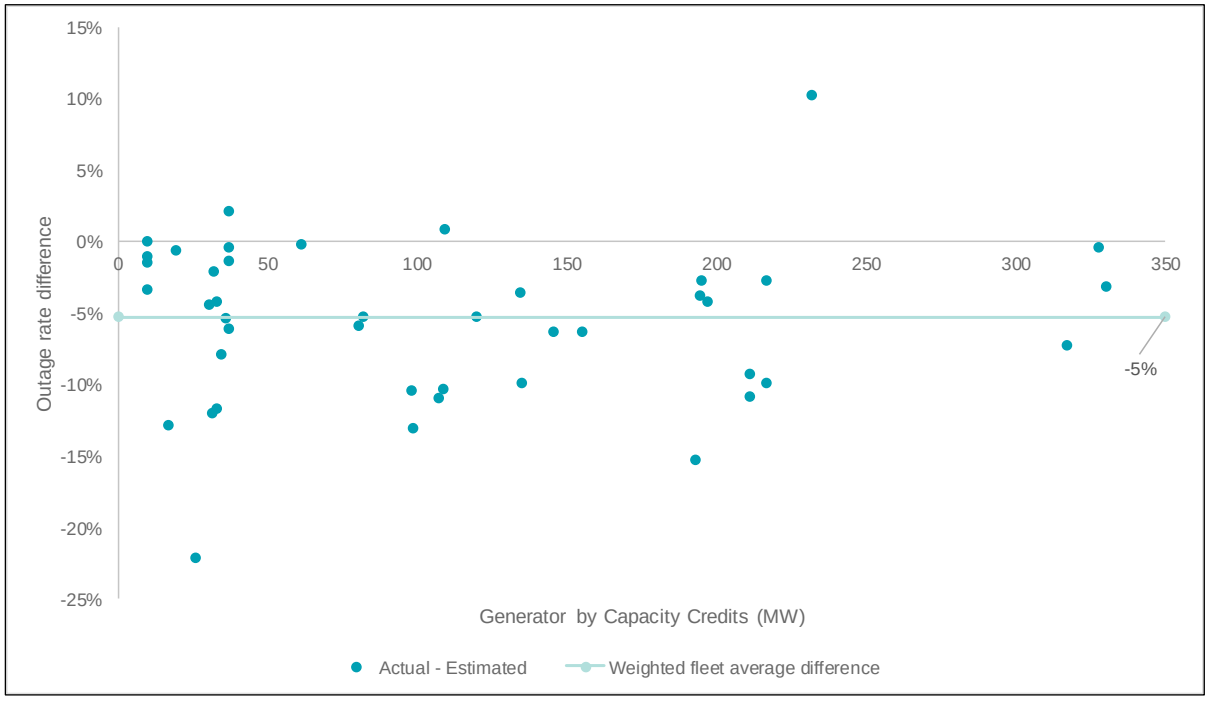
Source: ERA analysis of market data

Figure 2: Difference in outages for 2016 by generator



Source: ERA analysis of market data

Figure 3: Difference in outages for 2017 by generator

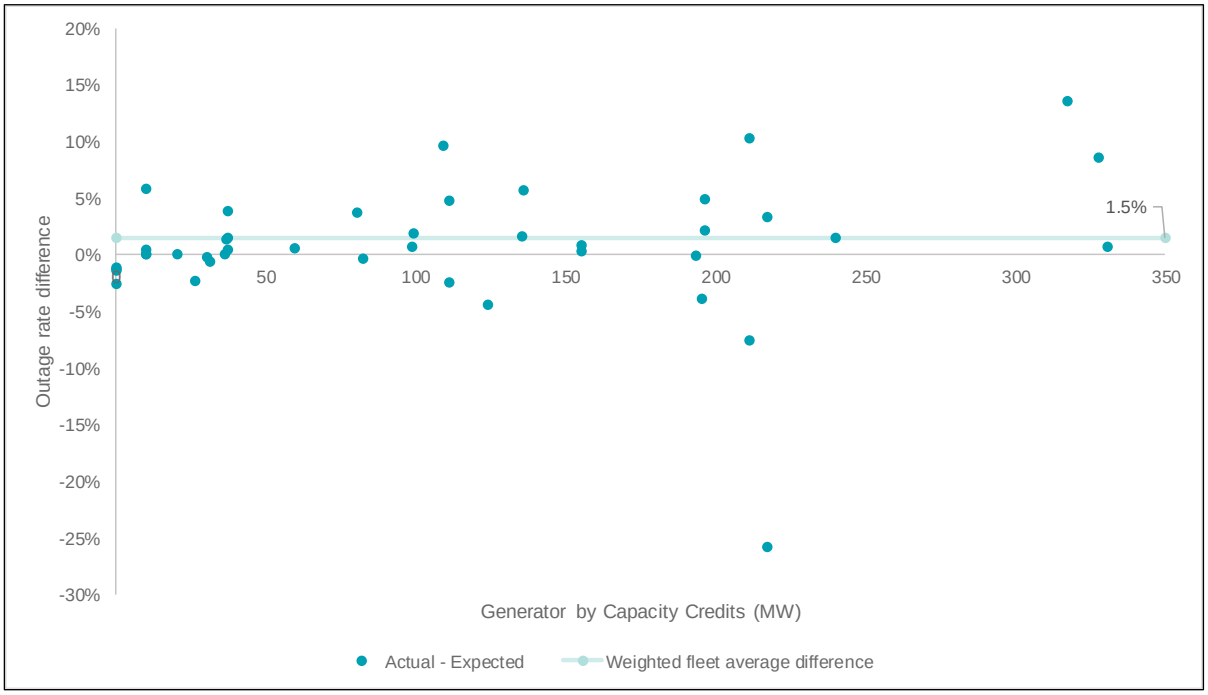


Source: ERA analysis of market data

Figure 4: Difference in outages for 2018 by generator

Source: ERA analysis of market data

Figure 5: Difference in outages for 2019 by generator



Source: ERA analysis of market data

WEM generator availability factor over time

The ERA also analysed the availability factor of the WEM generator fleet over time, in total and by fuel type (Table 9).

Table 9: WEM generator fleet 10-year Weighted Equivalent Availability Factors (WEAF)

WEM generators by fuel type	Average WEAF by capacity year (%)									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Gas	90	86	89	92	92	94	90	91	91	93
Dual (Gas / Distillate)	95	94	97	93	91	93	90	93	95	94
Coal	84	79	83	82	86	85	86	82	88	86
Coal/Gas[122]	60	62	74	81	91	90				
Distillate	99	96	92	89	98	87	95	97	97	93
Total WEAF per Year	**86**	**83**	**88**	**89**	**90**	**90**	**89**	**89**	**91**	**91**

Source: GHD Advisory 2020

The WEM's scheduled generator fleet fell to its lowest availability factor in the 2010 capacity year of 83 per cent and rose steadily over time to 91 per cent by the 2018 capacity year.

This is largely attributable to:

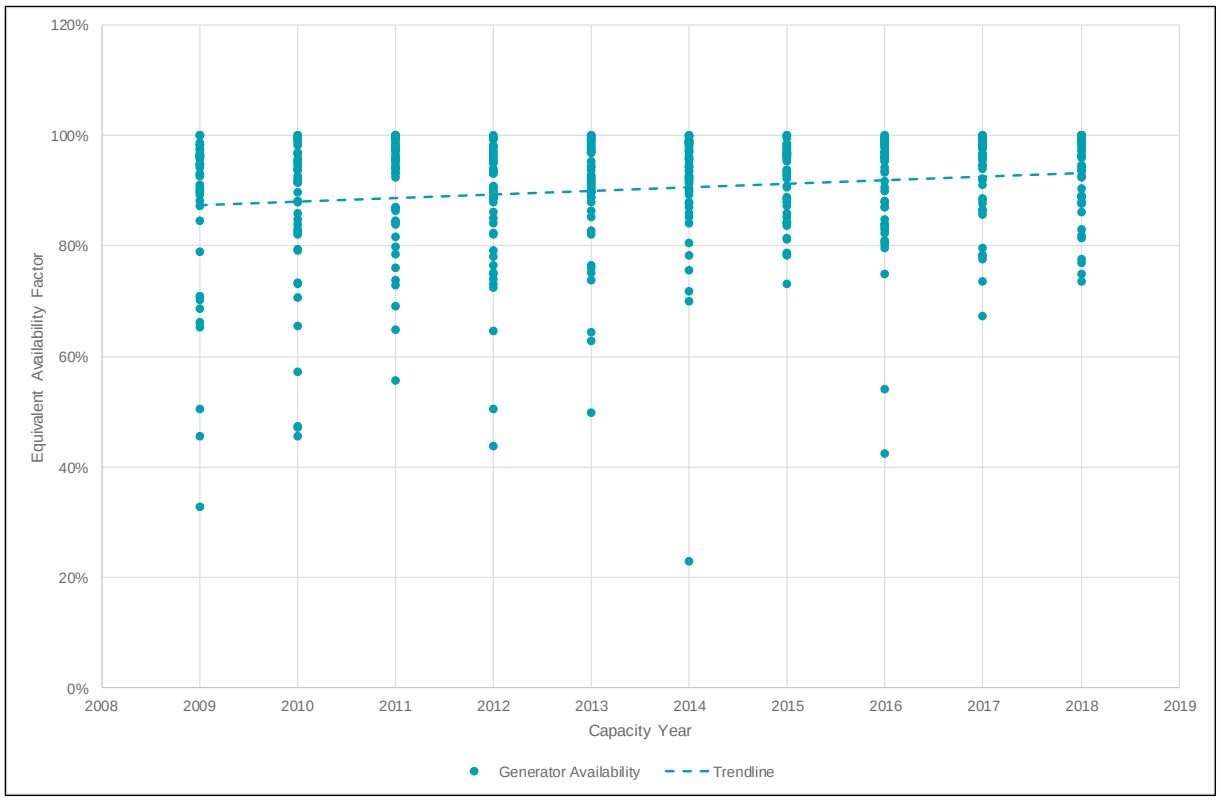
- Improvements in the coal and gas fleets' availability factor.
- Retirement of the coal/gas powered generators with lower availability factors, such as generators Kwinana G5 and G6 that belonged to Synergy.

Further analysis on each of the WEM's generator categories, such as coal, gas, and distillate are included in GHD Advisory's report.[123] The generator fleet's rising availability factor is shown in Figure 6.

[122] The last coal and gas generators (Synergy owned Kwinana units) were retired at the end of the 2014-15 capacity year.

[123] Economic Regulation Authority, 2020, *Generator Availability Analysis*, Report prepared by GHD Advisory, pp 19-31. (online).

Figure 6: Availability Factor of Generators participating in the Reserve Capacity Mechanism by Capacity Year



Source: ERA analysis of market data

Appendix 6 Minimum requirements for the REPO clause

The market rules set out the minimum requirements for the review of the REPO clause.[124] In assessing the minimum requirements, the market rules specify the assessment period as being from the time that the REPO clause was introduced (1 October 2017). The REPO count only applies to generators such as coal and gas plants, that are scheduled and dispatched by the market operator.

The introduction of the REPO clause placed a limit on the quantity of planned outages that a generator could take before triggering capacity refund payments for subsequent planned outages. A generator's REPO count is a rolling total based on the 1,000 trading days prior to the next planned outage. Therefore, a generator's REPO count varies as planned outages move outside of the 1,000-day calculation range. Although a generator may be close to the REPO count limit, future planned outages may not trigger the capacity refund if a past planned outage falls outside of the 1,000-day period.

Outage related information for all requirements were calculated based on AEMO's Power System Operation Procedure for Facility Outages.[125]

The REPO count and REPO count limit

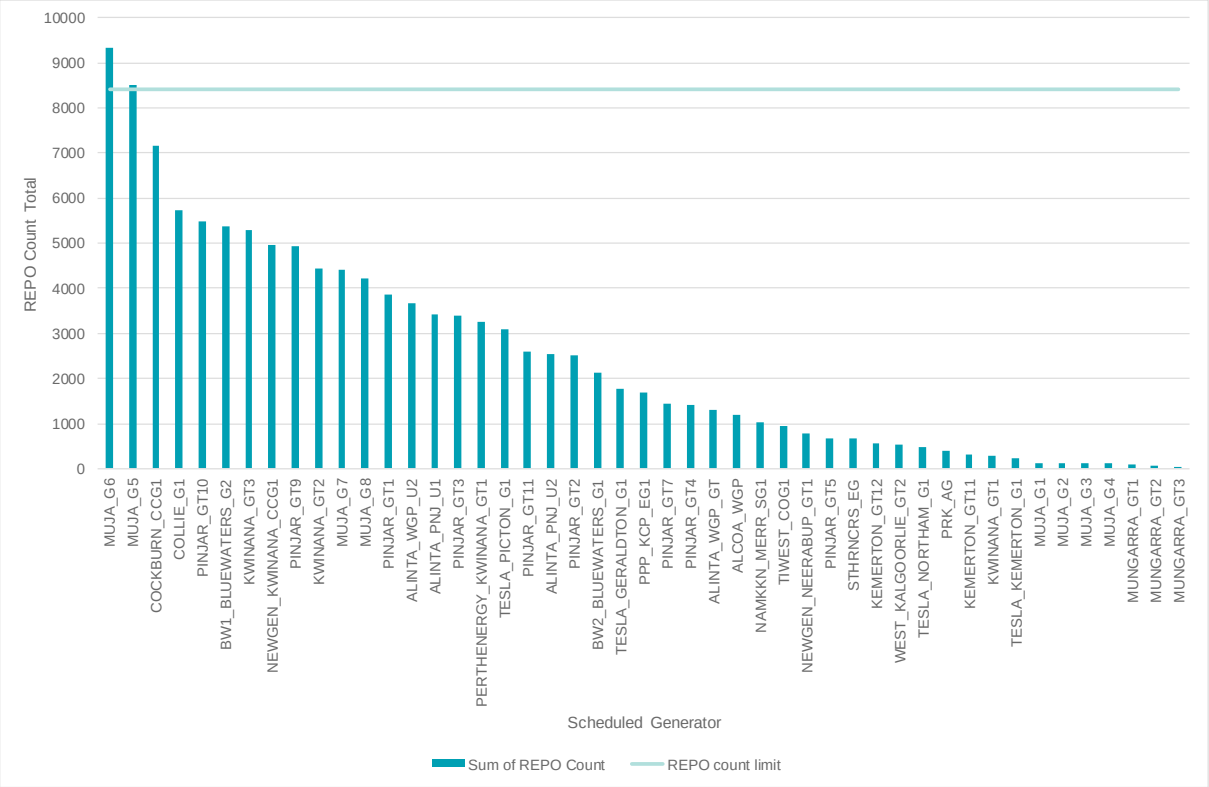
The REPO count measures the number of megawatts unavailable because of a generator's planned outage compared to the capacity credits that the generator held in that trading interval. The REPO count for each trading interval is summed over a 1,000-trading day period and compared to the REPO count limit to determine if the planned outage is subject to reserve capacity refunds.[126] An example of the REPO count of scheduled generators and the REPO count limit is illustrated in Figure 7.

[124] Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1D

[125] AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

[126] The REPO count is summarised in section 2.2 of this report.

Figure 7: Generator REPO count totals as at 28 April 2020



Source: ERA analysis of market data

Figure 7 shows the REPO count totals for generators at 28 April 2020. On this day, only generators Muja 5 and Muja 6 had REPO count totals above the REPO count limit. This means that if either Muja 5 or Muja 6 were to have a planned outage starting the next day, 29 April 2020, that planned outage would be subject to reserve capacity refunds. For all other generators below the REPO count limit, their next planned outage would not be subject to reserve capacity refunds.

The REPO count limit imposed by the Market Rules is 8,400 and equates to a 17.5 per cent planned outage rate.[127]

Variations in the planned outage rates and forced outage rates of generators[128]

The market rules require an assessment of forced and planned outage rates following the introduction of the REPO clause to assess if the clause had substantial effects on generator outages. If generators choose to limit their planned outages to avoid breaching the REPO count limit, this could result in an increase in forced outages.

The REPO count limit was introduced at the start of the 2017 capacity year.[129] The forced outage rates and planned outage rates for the generator fleet has been calculated based on the method outlined in AEMO's market procedure.[130]

127 Assessed over 1,000 trading days prior to the next planned outage of a scheduled generator. The limit is a measurement of equivalent trading intervals as they include partial outages in the calculation.

128 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1D(a)

129 A capacity year begins at 8 AM on 1 October of that year.

130 AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

For comparison and to provide context, the forced and planned outage rates for the two years prior to the commencement of the REPO clause are provided.

The generator fleet's figures are provided in two ways:

- Weighted based on the individual generator's assigned capacity credits relative to the total capacity credits assigned to all generators in that particular capacity year.
- As an equal weighted outage rate where all generators rank equally regardless of size.

The use of weighting is a simplistic method designed to obtain an overall view of the fleet. The weighting is based on the capacity credits assigned in a capacity year and does not differentiate between generators that are run more often and generators that operate only during peak times.

Table 10: Generator fleet forced outage rates

Forced outages	2015	2016	2017	2018	2019
Weighted forced outage rate	0.9%	3.3%	1.3%	2.5%	2.8%
Equal weighted outage rate	0.8%	2.5%	1.0%	2.2%	2.6%

Source: ERA analysis of market data

The overall fleet wide variations in forced outages do not appear to have been affected by the introduction of the REPO clause as the forced outage rate has been within the range of pre-REPO clause levels.

Table 11: Generator fleet planned outage rates

Planned outages	2015	2016	2017	2018	2019
Weighted planned outage rate	10.3%	8.2%	7.7%	6.4%	9.0%
Equal weighted outage rate	7.4%	7.1%	5.4%	5.7%	6.6%

Source: ERA analysis of market data

The planned outage rate decreased after the REPO clause was introduced and increased to pre-REPO clause levels by 2019.[131] Taken together with the observations on the forced outage rate, the results are inconclusive. There is insufficient data to determine if the introduction of the REPO clause has had a large effect on generator availability.

[131] The equal weighted outage rate figures differ slightly from the draft report figures as generators without capacity credits were originally included in the calculation. These have been removed and recalculated for the final report's figures.

The number of equivalent planned outage hours for which facility reserve capacity deficit refunds were payable[132]

The market rules require an analysis of the number of equivalent planned outage hours, above the REPO count limit, that each generator has had since the limit was introduced in 2017.[133]

Table 12: Number of equivalent planned outage hours

Facility	2017	2018	2019[134]
Cockburn CCG1	723	-	-
Muja G5	-	-	78.5
Muja G6	-	-	641
Pinjar GT9	-	43	-

Source: ERA analysis of market data

Note: All other generators, not named in the Table, did not have any equivalent planned outage hours for which refunds were payable.

Only four generators had planned outage hours that resulted in reserve capacity credit refunds. As planned outages are approved for maintenance events only, any planned outage hours in excess of the REPO count limit indicates facilities that had to take more maintenance in that capacity year than previously.

Differences to the figures in the draft report are:

- In consultation with AEMO, it was concluded that forced outages should be measured against the reserve capacity deficit amount instead of the awarded capacity credits to provide a more accurate measure. This reduced Cockburn's number of equivalent planned outage hours for 2017 down from 728 and removes the six hours from 2018. No other figures were affected due to this change.
- Muja G6 hours for 2019 includes the capacity year up to 31 August 2020.

The total amount of facility reserve capacity deficit refunds for refund payable planned outages[135]

This requirement shows the dollar value of reserve capacity refunds that were payable by generators that had planned outages above the REPO count limit.

132 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1D(b)(i)

133 Equivalent planned outages account for partial planned outages.

134 The 2019 capacity year is incomplete and only has data up to 31 August 2020.

135 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1D(b)(ii)

Table 13: Total value of facility reserve capacity deficit refunds

Facility	2017	2018	2019[136]
Cockburn CCG1	$535,657	-	-
Muja G5	-	-	$74,037
Muja G6	-	-	$683,736
Pinjar GT9	-	$21,174	-

Source: ERA analysis of market data

Note: All other generators, not named in the Table, did not have any equivalent planned outage hours for which refunds were payable.

The amount of refund compared to the number of equivalent planned outage hours will be different for each generator as it depends on when the outage was taken. Outages taken during times when there is low reserve capacity have higher refund rates than outages taken during times of high reserve capacity.

Differences to the figures in the draft report are:

- As explained for equivalent forced outages hours, the accounting for forced outages now uses the generator's reserve capacity deficit interval amount instead of awarded capacity credits to provide increased accuracy. This reduces Cockburn's facility reserve capacity deficit refunds due to planned outages above the REPO count limit down from $561,656 for 2017 and removed the $12,430 amount for 2018. No other amounts were affected due to this change.
- The Muja G6 facility reserve capacity deficit refunds for 2019 was revised down from $697,850 as this was based on preliminary data. The figures have been updated with finalised data available up to 31 August 2020.

Level of participation by generators in the reserve capacity mechanism[137]

This analysis was conducted to determine if there has been a material change in participation by generators in the Reserve Capacity Mechanism (RCM) since the REPO clause began. These results have not changed from the figures stated in the issues paper and draft report.

Table 14 shows the number of generators within the SWIS that were assigned capacity credits in the associated capacity year. The 2017 capacity year column is shaded grey to denote the start of the REPO clause.

136 The 2019 capacity year is incomplete and only has data up to 31 August 2020.

137 Wholesale Electricity Market Rules (WA), 7 August 2020, Rule 4.26.1D(c)

Table 14: Number and proportion of generators with capacity credits by fuel type by capacity year

Capacity year	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total number of generators	52	52	50	48	48	39	39	39	38
Fuel type:									
Coal Proportion	11 21%	11 21%	11 22%	11 23%	11 23%	7 18%	7 18%	7 18%	7 18%
Diesel/Oil Proportion	7 13%	7 13%	7 14%	7 15%	7 15%	7 18%	7 18%	7 18%	7 18%
Dual fuel Proportion	19 37%	19 37%	19 38%	19 40%	19 40%	17 44%	17 44%	17 44%	17 45%
Gas Proportion	13 25%	13 25%	13 26%	11 23%	11 23%	8 21%	8 21%	8 21%	7 18%
Tri-fuel (coal, gas and oil) Proportion	2 4%	2 4%	0	0	0	0	0	0	0

Source: ERA analysis of market data

Changes in the mix of generators that have participated in the RCM[138]

This analysis is to demonstrate if generators with particular fuel sources were affected materially by the introduction of the REPO clause. These results have not changed from the figures stated in the issues paper and draft report.

Table 15 shows the contribution of each generator fuel type to the fleet by capacity credits, not the number of generating units (Table 14). This is to assess if the REPO clause may have

[138] Ibid. Rule 4.26.1D(d)

changed the composition of the generator fleet for example, by substitution of lower maintenance gas generators in place of higher maintenance coal generators.

Table 15: Number and proportion of capacity credits per scheduled generator fuel type by capacity year

Capacity year	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total scheduled generator capacity credits	5,382	5,387	5,025	4,952	4,978	4,639	4,639	4,642	4,606
Fuel type:									
Coal Proportion	1,771 33%	1,777 33%	1,778 35%	1,778 36%	1,781 36%	1,561 34%	1,561 34%	1,561 34%	1,561 34%
Diesel/Oil Proportion	147 3%	147 3%	147 3%	149 3%	149 3%	149 3%	149 3%	149 3%	149 3%
Dual fuel Proportion	1,603 30%	1,608 30%	1,615 32%	1,637 33%	1,658 33%	1,623 35%	1,623 35%	1,623 35%	1,623 35%
Gas Proportion	1,499 28%	1,494 28%	1,485 30%	1,389 28%	1,390 28%	1,305 28%	1,305 28%	1,309 28%	1,273 28%
Tri-fuel (coal, gas and oil) Proportion	362 7%	362 7%	0	0	0	0	0	0	0

Source: ERA analysis of market data

From Table 14 and Table 15, there has been no substantial change in generators participating in the RCM or the composition of those generators since the introduction of the REPO clause. The changes between the 2017 and 2018 capacity years is mostly attributable to the retirement of 330 MW of generation by Synergy at the direction of the Minister for Energy.

Appendix 7 Assessment framework

The market rules require the ERA to assess whether the clauses under review require changes to better meet the WEM objectives. To do this the ERA devised two assessment criteria; consistency with the planning criterion and a reliable measure of capacity contribution.

The Reserve Capacity Mechanism (RCM) supports the objectives of the WEM when the measurement of capacity contribution is both consistent with the planning criterion and a reliable measurement of a generator's capacity contribution. Although outside the scope of the two reviews, the same two criteria could be applied to the RCM to identify where the RCM is restricted in achieving WEM objectives.

Applying the assessment showed that the clauses under review are inconsistent with the planning criterion and contribute to an unreliable measure of both the expected and actual capacity contribution of generators. This adversely affects the WEM objectives, particularly the objectives of avoiding discrimination against particular energy technologies and of minimising the long-term cost of electricity supplied to customers.

Table 16: Comparison of the clauses against the assessment criteria

Assessment criteria	Reserve capacity reduction clause	REPO clause
1. Consistent with the planning criterion	Partially consistent: clause allows for some accounting for outages.	Clause does not account for outages during periods of high demand.
2. A reliable measure of the capacity contribution	Clause provides an unreliable measurement as AEMO cannot apply the provisions in the clause to all generators.	Clause measures outages, not a generator's capacity contribution.

The assessment criteria are explained in more detail below.

Consistent with the planning criterion

To be consistent with the planning criterion, the measurement of a generator's capacity contribution should consider availability during periods of extremely high demand. As availability varies with outages, the measurement of expected capacity contribution must account for this uncertainty. Inconsistency with the planning criterion can undermine the reliability of the system and can increase the long-term supply cost of electricity to consumers.

If the RCM does not reliably account for outages occurring during periods of high demand, as specified in the planning criterion:

- AEMO may under-procure capacity. When reserve capacity falls short of the reserve capacity target or there is limited excess capacity, there is a risk to the reliability of the system and possibly supply may be lost, causing blackouts. Therefore, the cost to consumers of under-procuring capacity is large.[139]
- AEMO may not correctly calculate a generator's actual contribution to system adequacy. For example, if AEMO under-estimates the actual capacity contribution of a generator, the

[139] Under conditions of limited excess capacity, each additional unit of capacity procured avoids a large amount of unserved energy to consumers.

generator would refund payments of capacity credits more than required. Generators would incur costs by paying excessive refunds or investing in ways to avoid outages. Ultimately consumers pay for those costs.

A reliable measure of the capacity contribution

The reliable measurement and pricing of capacity is essential to ensuring that there is enough capacity available when needed and that the cost of this capacity aligns with the objective to minimise the long-term cost of electricity to consumers.

A reliable measure of capacity contribution includes all factors which materially affect a generator's contribution. This applies when measuring a generator's expected future contribution during the certification of capacity, and the actual contribution during the capacity credit refund stage. Both the over and under estimation of capacity contribution hinders the achievement of WEM objectives.

Some generators' capacity contribution varies by air temperature and outages: these factors are integral to a reliable measure of the generator's expected contribution. Outages on very hot days, when there is high demand for electricity, will have a larger effect on the generator's contribution to system adequacy than outages during periods of low demand. In addition, reliability challenges can arise on low demand days if many generators are on outage simultaneously. When penalising generators for outages the dynamic refund mechanism considers how the availability of other generators affects reliability.

To support the WEM objectives, the measure of capacity contribution needs to be both reliable and used consistently for both expected and actual capacity contribution.

Meeting the criteria

- Reserve capacity reduction clause:
  - If the clause is consistent with the planning criterion then it will enable AEMO to procure enough capacity to ensure system adequacy.
  - If the clause is a reliable measure of capacity contribution, then generators will only be certified reserve capacity based on their estimated contribution to system adequacy.
  - In both cases the clause lowers the risk of passing on costs to customers because AEMO has under-procured or over-procured capacity.
- REPO clause:
  - If the clause is consistent with the planning criterion, then it will only apply to planned outages that occur when the system is under stress.
  - If the clause is a reliable measure of capacity contribution, then it will only penalise generators for the gap between their estimated and actual capacity contribution.
  - If the clause meets both assessment criteria, customers will not be paying for capacity that was expected but not delivered when required. Generators who take planned outages when there is excess capacity in the system will not be penalised and so will not pass these costs onto consumers.

Appendix 8 Reserve Capacity Reduction Clause: Proposed Method

The reserve capacity reduction clause (4.11.1(h)) gives AEMO the discretion to reduce a generator's certified reserve capacity but no direction on how to apply this discretion. During the review of this clause, AEMO requested guidance on applying the clause to ensure that any decisions are consistent and transparent. The ERA and AEMO are developing this guidance to explain to the market how AEMO will apply the reserve capacity reduction clause.

The ERA has developed the proposed method outlined in this appendix to support its proposal to extend AEMO's discretion under the reserve capacity reduction clause by reducing the outage thresholds to zero. The proposed method will be included in the rule change proposal and will be subject to more detailed development by AEMO, the ERA and feedback from market participants.

Assumptions of the proposed method

- A generator's certified reserve capacity will be assigned based on its forecast expected contribution to meeting the reliability requirement of the planning criterion. This is similar to the approach used in the Pennsylvania-New Jersey-Maryland Interconnector (PJM) capacity market for determining a generator's contribution to meeting its system reliability requirements.[140] Assigning capacity credits in this way reduces the risk of over-forecasting expected capacity, reducing the long-term costs of supplying electricity to consumers.
- Outages that are expected during periods of system stress reduce a generator's contribution to system adequacy.
- The number of capacity credits a generator is assigned depends on the probability of that generator having outages during system stress periods.
- The outage rate will be calculated using an Equivalent demand Forced Outage Rate (EFORd) formula for each generator, which provides an estimate of the probability of having forced outages during periods of system stress.
- When AEMO is determining a generator's certified reserve capacity, AEMO can take into account factors that will affect the outage rate of that generator during system stress periods.

Proposed method for applying the reserve capacity reduction clause

The ERA proposes the following method for AEMO to use when determining a generator's capacity contribution under the reserve capacity reduction clause. This is to provide market participants with an insight into the steps that will be required for assessing generators. These steps will be subject to change as the rule change proposal is developed.

1. AEMO forecasts a generator's future forced outage rate during periods of system stress using the outage history of generators as a proxy.[141]

[140] PJM, 2020, *PJM Manual 18, PJM Capacity Market, Revision: 45*, (online) and PJM, 2020, *PJM Manual 20, PJM Capacity Market, Revision: 10*, (online).

[141] The current calculation of forced outage rate under the market procedure does not provide a reasonable forecast of the probability of a generator's outages occurring during system stress periods. This is because

i. To forecast a generator's future forced outage rate, AEMO will use an EFORd formula as it is a measure of the probability that a generator will not be available due to forced outages when required to run.[142] This EFORd calculation will be based on the IEEE standard for defining generator reliability, availability and productivity and use a generator's historical outage data.[143,144]

2. Generators provide AEMO with their own EFORd number based on evidence showing why their estimate would be different to that calculated by AEMO using historical data. A generator's reasons for the difference could include:

   i. Providing details on actions taken to reduce that generator's risk of outages during system stress periods.

   ii. Demonstrating how the actions taken would have changed that generator's historical outages and thus the resulting EFORd.

   iii. How the generator will account for any residual risk of outages despite the actions taken to mitigate them.

   This allows AEMO to consider action taken by the generator, such as additional maintenance to minimise the risk of outages occurring in the future. If generators do not provide an EFORd number, then AEMO will use historical data for the next step.

3. If a generator has proposed an alternative EFORd with supporting documentation, AEMO chooses whether to use:

   i. The generator's proposed EFORd.

   ii. The EFORd calculated using historical outage data.

   iii. Another value AEMO considers reasonable.

   If no alternative EFORd was provided, AEMO will calculate the generator's EFORd based on historical outage data.

   Publishing AEMO's reasons on how it arrived at a generator's EFORd will provide transparency on the assessment.

4. AEMO then uses the generator's EFORd to determine the certified reserve capacity of a generator, consistent with their forecast expected contribution to system reliability. The formula for calculating this is:[145]

the outage rate calculation in the market procedure calculates a generator's outage rate over a period regardless of whether a generator was running or not.

The current calculation for facility outages is contained in the following market procedure. AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

142 The Institute of Electrical and Electronics Engineers [IEEE] 2016, *IEEE Standard 762-2016 IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, (online) [accessed 19 March 2020].

143 Ibid.

144 The calculation is likely to assess three to five years of historical outage data with the exact period to be determined as part of the rule change development process.

145 Garrido P. Pennsylvania-New Jersey-Maryland Interconnection (PJM), 2020, 'Effective Load Carrying Capability (ELCC)', *Resource Adequacy Planning,* (online) p. 8.

$$Certified\ Reserve\ Capacity = rated\ capacity\ at\ 41\ C \times (1 - EFORd)$$

This formula reflects:

i. The expected available capacity of a generator during high system stress periods.

ii. The effective load carrying capability, or equivalent firm capacity, of a generator.[146,147]

5. After assessing these generators, the capacity certification process continues as per the market rules.

Challenges with the Reserve Margin in the Planning Criterion

The planning criterion contains a reserve margin, which includes an outage allowance that acknowledges generators will incur some level of forced outages. AEMO must consider the outage allowance in the reserve margin before discounting the capacity value of generators. If not, outages may be double counted, first in the assignment of capacity credits step and again in the procurement of overall reserve capacity to meet the reserve capacity target. The ERA will work with AEMO on how to address this challenge as part of the rule change development process.

A possible solution to mitigate the risk of double-counting outages is to:

- Determine the gap between the number of expected outages assumed in the reserve margin and the EFORd capacity amount for the total generator fleet.
- Allocate the gap between all generators in proportion to each generator's contribution to system adequacy.

This means that generators with greater contributions to system adequacy will not be discounted by as many capacity credits compared to generators with lesser contributions.

The reserve margin is part of the review of the planning criterion, which Energy Policy WA is now responsible for under the latest energy market reforms. The double-counting risk could be considered as part of a planning criterion review.

Exclusion: Planned outages

Planned outages are not included in the proposed method for determining a generator's contribution to system reliability as planned outages are expected to run only during times of low reliability stress in the system. This means that the effect of planned outages on the capacity contribution of a generator is minor.

Outside the high reliability stress periods in the system, AEMO has no current concerns that there is not enough spare available capacity to allow generators to take planned outages.[148] In the future, if AEMO determines that there is not enough room for generators to schedule

146 Zachary S and Dent C J, 2011, 'Probability theory of capacity value of additional generation', *Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability*, vol. 226, issue. 1, (online) pp. 5-8. [accessed 24 November 2020].

147 For scheduled generators, with independent available capacity from system demand and other generators, effective load-carrying capacity is equal to expected available capacity during system stress periods.

148 AEMO, 2020, *Final Report: 2020 Assessment of System Reliability, Development of Availability Curve and DSM Dispatch Quantity Forecasts for the South West Interconnected System*, Report prepared by Robinson Bowmaker Paul, pp. 10-13.

planned outages during periods of low system stress, planned outages may be scheduled during system stress periods. If this occurs, then the method proposed in this appendix will need to change. This will be considered as part of the rule change proposal development process.

Applying the proposed method: Administration costs

Reducing the outage thresholds to zero allows AEMO to determine expected outages for all or any generators. AEMO advised that assessing all generators may increase administration costs. AEMO estimated that it typically requires an equivalent of seven business days to assess a generator's outages. The process includes verifying the reasons for the generator's outages and liaising with other areas such as System Management to evaluate the effects of those outages.

To mitigate a possible increase in its administration costs, AEMO proposed adding a new threshold to limit the number of generators that AEMO needs to assess each year.

The rule change development process will consider any administration costs against the benefits to consumers of assessing only a limited number of generators, or all generators. Limiting the number of generators to be assessed can only be consistent with market objectives if the administration costs will exceed expected long-term benefits to consumers of assessing all generators.

Appendix 9 provides a value of customer reliability analysis to demonstrate the implications of introducing a limit on the number of generators AEMO assesses under the reserve capacity reduction clause. This preliminary analysis will be used to inform the development of the rule change proposal.

Appendix 9 Benefits for consumers

Currently, the reserve capacity reduction clause enables AEMO to assess the contribution to system adequacy of those generators that breach the outage thresholds. The ERA's proposal that the outage thresholds be reduced to zero will allow AEMO to assess any or all generators. However, as raised in Synergy's submission and confirmed by AEMO, there may be additional administration costs for AEMO to assess more generators.[149] To reduce costs, AEMO asked if the ERA could consider the use of a filter to limit the number of generators that AEMO would need to assess under the reserve capacity reduction clause. The ERA analysed the indicative value to consumers of AEMO assessing more generators to compare possible increased administration costs against expected market benefits.

The preliminary analysis outlined in this appendix shows that if a filter or threshold is introduced, this risks over-forecasting capacity and consumers pay for capacity that is not likely to be available. For example, if just the top five generators with the highest outage effect have their outages considered when capacity credits are assigned, this would result in a loss of benefits to consumers of between $1.2 million and $4.5 million. The loss in benefit is linked to the over-forecasting of capacity that occurs from the remaining generators whose outages are not considered when capacity credits are assigned.

The loss in benefit to consumers is the capacity they pay for that is not delivered. As discussed in section 3 of the report, generators may be assigned more capacity credits if their forced outages are not considered when capacity is certified. Generators with high levels of forced outages have a higher likelihood of not being able to provide electricity when required to generate. By not accounting for forced outages, customers are not receiving the level of reliable electricity supply that they are paying for.

This appendix explores the setting of various thresholds or numbers of generators assessed under the reserve capacity reduction clause and the associated benefits for consumers.

The preliminary analysis demonstrates the sizable cost to consumers of using thresholds to assess only some generators. The analysis will be updated as the rule change proposal is developed.

Assessing a threshold and its value to consumers

It is reasonable to expect AEMO will incur additional costs if it has to consider the outages of all generators when assigning capacity credits, rather than the two to five generators considered at present. Any increased cost should be compared against the loss in benefit to consumers from paying for capacity that is not delivered.

The ERA has calculated the value to consumers of only accounting for the outages of a subset of generators.

The assessment looked at the effect of outages on the capacity contribution of a subset of n generators out of all N generators applying for capacity credits in a target capacity year. The assessment then calculated the expected decrease in reliability benefits delivered to consumers from ignoring the effect of outages for the remaining generators.

Each generator g, applying for certification of its reserve capacity, had the effect of its expected forced outages on its capacity contribution, d_o, calculated using the equation below.

[149] Synergy, 2020, Submission to 2020 review of incentives to improve availability of generators – Draft report, p 3.

This equation accounts for the effect of expected outages during system stress periods on the capacity contribution of the generator, and is referred to as the outage effect:

$$d_o = Rated\ capacity\ at\ 41 - Rated\ capcity\ at\ 41 \times (1 - EFOR_d)$$
$$= EFOR_d \times rated\ capacity\ at\ 41$$

Assuming AEMO discounts the certified reserve capacity of n generators with the largest outage effect d_o only, this results in an assessed generator set comprising n generators. This analysis assumes that AEMO does not discount the certified reserve capacity of the remaining $(N - n)$ generators, referred to as the non-assessed generator set.

Limiting the assessment of the effect of outages to generators in the assessed generator set only results in over-forecasting the capacity contribution of generators in the non-assessed generator set. The total size of the over-forecasting error, expressed in MW, for the generators in the non-assessed generator set is calculated by:

$$e = \sum_{g=N-n}^{N} d_{o,g}$$

The cost to consumers of a difference in excess capacity e when certifying reserve capacity can be estimated using the value of customer reliability (VCR) curve.[150] The VCR curve indicates the value of procuring incremental capacity credits to consumers.

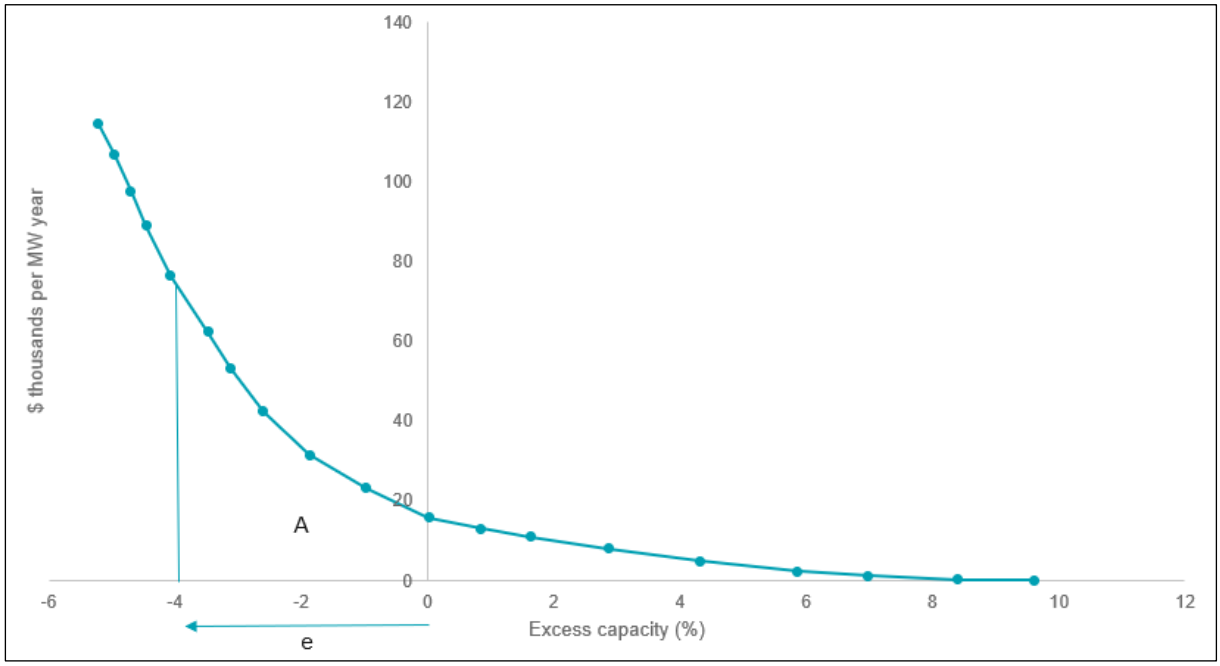
Figure 8 shows an example expected VCR curve with an area 'A' and value e for illustrative purposes.[151] As more capacity is procured, the value to consumers of each additional amount of capacity reduces. This is because further increases in capacity do not improve system reliability by as much as previously procured capacity.

The area under the VCR curve between two different points is the difference in benefits consumers would receive from procuring those levels of capacity. Since the planning criterion sets the amount of capacity credits required, if exactly this amount of capacity is procured, then there will be zero per cent excess capacity. However, where there is an over-forecasting error, the reduction in capacity contribution reduces the benefit that consumers receive. This is because the total benefit to consumers of procuring capacity credits decreases by area 'A' (see Figure 8 - the four per cent deficit figure is illustrative only).

150 Excess capacity is measured by the amount of capacity above the Reserve Capacity Target expressed as a percentage.

151 The ERA derived this Value of Customer Reliability Curve from - Government of Western Australia, Public Utilities Office, 7 February 2019, *Improving Reserve Capacity pricing signals – a recommended capacity pricing model, Final recommendations report,* p. 24, (online)

Figure 8: Illustrative Expected Value of Customer Reliabilty (VCR) curve



Source: ERA derived Value of Customer Reliability Curve from Public Utilities Office reserve capacity pricing signals publication.[152]

Note: the area under the VCR curve up to the amount of capacity credits procured reflects total benefits to consumers of procuring capacity credits.

The larger the size of error e, the larger the reduced benefit to consumers of over-forecasting capacity values. Additionally, as the size of the forecasting error e increases, the rate of reduction in benefit to consumers increases. The forecasting error can be expected to increase as the number of generators in the non-assessed set also increases.

The capacity credit procurement mechanism allows the procurement of capacity above the quantity required to meet the planning criterion. At extremely large amounts of excess capacity in a capacity year, customers pay for the excess capacity but with negligible additional benefit.

Planned outages are not part of this assessment as they have a minimal effect on a generator's expected capacity contribution to system adequacy. As discussed in Appendix 8, this is because planned outages are expected and scheduled during times of low system stress.

Preliminary analysis

When determining a generator's capacity credits, AEMO considers only the forced outages of those generators with outage rates above the thresholds in the market rules. Generators that do not have outage rates above these thresholds are assigned capacity credits equal to their output at 41 degrees Celsius. By not assessing the outages of all generators, the capacity credits assigned and procured by AEMO may be above the amount of capacity that is likely to be available during times of system stress. This could jeopardise meeting the requirement to have enough capacity to meet a one in 10-year peak demand event.

[152] Government of Western Australia, Public Utilities Office, 7 February 2019, *Improving Reserve Capacity pricing signals – a recommended capacity pricing model, Final recommendations report,* p. 24, (online)

Equivalent Forced Outage Rate

The ERA calculated an Equivalent Forced Outage Rate (EFOR) for each individual generator. EFOR was used instead of EFORd due to data limitations.[153] EFOR is the percentage of operating time that a generator is out of service and cannot reach full capacity due to equipment failures and indicates the probability that a unit will not be able to generate as much electricity as required.[154] The main difference between EFOR and EFORd is that EFORd includes only the time periods when a generator would have been required to generate while EFOR includes the total outage time. EFOR provides a useful proxy of the probability that a generator's capacity will be available when called on and is adequate for the purpose of approximating the value that customers place on reliability.

The forced outage rate calculation in the existing market procedure was not used as it calculates a generator's outages over a set period of time, for example over a year, regardless of whether a generator was called to run or not.[155,156] Section 3.2.3 demonstrates how an unreliable generator can still have a low outage rate based on the market procedure calculation yet also have a high EFOR.

The fleet EFOR is a consolidation of each individual generator's EFOR.[157] The five years of data provides a range of EFOR values that is used to estimate the change in benefit to customers. This change in benefit to customers is measured as the gap between the level of reliability expected when capacity is procured and the level of reliability that is delivered. The greater the EFOR value, the lower level of reliability that customers are receiving and the greater the likelihood of electricity supply interruptions.

This analysis assumes that past performance over the last five years is a reasonable predictor of future performance. The outage pattern observed in the past is likely to be observed in future years. Although generators observed EFOR changes from year to year, when considered as a set, the calculated outage effects and estimated size of forecasting error e would provide a reasonable estimate of the size of the forecasting error e in future years. The analysis produces a sample of five forecast error e.

Table 17: Equivalent Forced Outage Rate (EFOR) for the generator fleet by capacity year

	2015	2016	2017	2018	2019
EFOR	5.1%	6.7%	7.5%	8.1%	7.0%

Source: ERA analysis of market data

The EFOR has remained within a range of between five to eight per cent over the last five years. Table 18 shows this difference between the amount of capacity procured for generators

153 The Equivalent demand Forced Outage Rate (EFORd) is explained in Appendix 8 and references formula from - The Institute of Electrical and Electronics Engineers [IEEE] 2016, *IEEE Standard 762-2016 IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, (online) [accessed 19 March 2020].

154 Generation Consulting Services, LLC, 'Reliability Analysis of Power Plant Unit Outage Problems', (online) [accessed 20 October 2020].

155 AEMO, 2020, *Power System Operation Procedure: Facility Outages,* pp. 17-18.

156 The EFOR calculation was adopted from: The Institute of Electrical and Electronics Engineers [IEEE] 2016, *IEEE Standard 762-2016 IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, (online) [accessed 19 March 2020].

157 Each generator was calculated a separate EFOR figure to determine the number of capacity credits that would have been reduced. These capacity credits were summed up and the total compared to the total capacity credits assigned to the generator fleet for that year to arrive at the fleet's EFOR.

and the quantity of capacity accounting for the fleet's EFOR. This provides a range of capacity quantities that can be used to estimate the reliability benefit consumers did not receive because of the generator fleet's forced outages.

Table 18: Difference in capacity credits due to generator fleet Equivalent Forced Outage Rate

	2015	2016	2017	2018	2019
Capacity credit difference (MW)	255	331	374	374	327

Source: ERA analysis of market data

To meet the planning criterion, enough capacity credits need to be procured to meet the reserve capacity target. Using 2019 as an example, after accounting for EFOR, there was 99 MW of capacity that was under-procured to meet the reserve capacity target (Table 19) after accounting for generators' forced outages.

Table 19: 2019 reserve capacity accounting for fleet EFOR[158]

	2019
Reserve Capacity Target (MW)	4,660
Total capacity credits procured (MW)	4,888
Total expected capacity credits (based on historical EFOR) (MW)	4,561
Expected capacity shortfall[159] (MW)	(99)
Level of excess (deficit) capacity	(2.1%)

Source: ERA analysis of market data

To illustrate using Figure 8, assume that the level of excess capacity, after accounting for the EFOR of generators, is -2.1 per cent. If the amount of capacity needed to meet the planning criterion is zero per cent excess capacity, then the area between these two values (-2.1 per cent and zero per cent excess capacity) represents the reduction in benefit to consumers from the over-forecasting of capacity credits for generators. By not discounting generators in line with their contribution to system adequacy, consumers are receiving a lower level of reliability than they are paying for.

Table 20 shows the change in benefits delivered to consumers after accounting for the generator fleet EFOR.[160]

158 All figures in Table 19 are rounded to the nearest MW.

159 The expected capacity shortfall is calculated as the total expected capacity credits after accounting for EFOR minus the reserve capacity target.

160 A value of customer reliability curve (see Figure 8) varies depending on the customers to a system. The Public Utilities Office VCR curve has been used an estimated proxy for each year in the analysis.

Table 20: Value of customer reliability accounting for the generator fleet's Equivalent Forced Outage Rate

	2015	2016	2017	2018	2019
Capacity credits procured	5,683	5,618	5,193	4,819	4,888
Difference in capacity credits after accounting for all generators' EFOR	255	330	374	374	327
Change in benefit delivered to consumers	$11.6m	$21.8m	$35.8m	$42.2m	$27.0m

Source: ERA analysis of market data

The lowest estimated change due to the EFOR capacity credit difference was $11.6 million, which is the difference in value between procuring 5,683 capacity credits and 5,428 capacity credits.[161]

Table 21 presents the results of the analysis of using various thresholds to assess the change in benefits to consumers. That is, only the top 5, 10 and 15 generators with the highest outage effect had their EFOR considered when reserve capacity was assigned. The remaining generators received no EFOR reduction.[162]

Table 21: Decrease in the benefit to consumers of assessing the top 5, 10 or 15 generators with the largest outage effect in descending order ($ m)

Generator outage effect	2015	2016	2017	2018	2019
Top 5	1.5	1.2	2.4	3.2	4.5
Top 10	0.7	0.6	1.0	0.9	1.9
Top 15	0.3	0.3	0.4	0.3	0.8

Source: ERA analysis of market data

If only the top 5 generators with the largest outage effect had their reserve capacity adjusted, there would be a loss of benefits to consumers of between $1.2 million and $4.5 million from the over-forecasting of capacity from the unassessed set of generators.

If the value of evaluating all generators will prevent a larger forgone benefit to consumers, it could support AEMO justifying any additional cost it may incur from assessing all generators under the reserve capacity reduction clause. This method of analysis will be used as part of the rule change development process to assess benefits and costs of the proposal.

[161] 5,428 capacity credits is equal to 5,683 capacity credits procured minus 255 capacity credits after accounting for generators' EFOR. The change in benefit to consumers also assumes that the number of capacity credits procured is equal to zero per cent excess capacity in the VCR curve (see Figure 8).

[162] There are 38 scheduled generators in the WEM as of 2019. Since the Kalamunda generator only generates 1.3 MW, it is under the 10 MW threshold and was not included in the calculations.