RCP | Rule Change Panel

Rule Change Notice: Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03)

This notice is given under clause 2.5.7 of the Wholesale Electricity Market Rules (**Market Rules**).

Submitter: Fan Zhang, Collgar Wind Farm (**Collgar**)

Date submitted: 1 March 2018

The Rule Change Proposal

Appendix 9 of the Market Rules defines the Relevant Level Methodology, which is used by the Australian Energy Market Operator (**AEMO**) to determine the level of Certified Reserve Capacity for a Facility (usually an Intermittent Generator) under clause 4.11.2(b) of the Market Rules.

The Relevant Level Methodology uses the concept of Load for Scheduled Generation (**LSG**). The LSG for a Trading Interval represents the system demand in the Trading Interval that would need to be met by Scheduled Generators. It is calculated as the total metered generation for the Trading Interval, plus any voluntary or involuntary load reduction that occurred in the Trading Interval, minus the total generation provided by Intermittent Generators.

The Relevant Level of an Intermittent Generator is based on its output (or estimated output for new Facilities) during the 12 peak LSG Trading Intervals in each of the previous five years.

Collgar considers the Relevant Level Methodology to be flawed and discriminatory against intermittent generation technologies because it is arbitrary and overly conservative in allocating Capacity Credits to Intermittent Generators. Collgar's main concern is that the LSG concept does not provide a direct link between the requirement for capacity to meet system peak periods and the ability of Intermittent Generators to make capacity available during those peak periods.

Collgar proposes to replace the use of peak LSG Trading Intervals in the Relevant Level Methodology with the use of actual system peak Trading Intervals, defined as those Trading Intervals where the sum of total metered generation and any voluntary or involuntary load reduction is greatest. Collgar suggests that this will provide a more direct link between the requirement for capacity in peak periods and the ability of Intermittent Generators to provide capacity during the periods with the highest demand on the system.

The Rule Change Proposal, which is attached to this notice, gives complete information about:

- the proposed amendments to the Market Rules;
- the relevant references to the Market Rules and any proposed specific amendments to those clauses; and
- Collgar's description of how the proposed amendments would allow the Market Rules to better address the Wholesale Market Objectives.

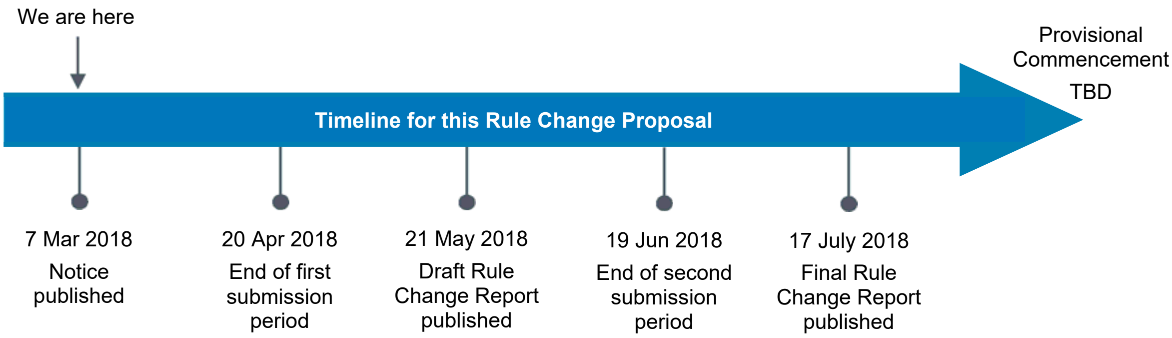
Decision to progress the Rule Change Proposal

The Panel has not had an opportunity to assess this Rule Change Proposal against the Wholesale Market Objectives. The Panel has decided to progress this Rule Change Proposal on the basis that due consideration should be given to whether the proposal will allow the Market Rules to better address the Wholesale Market Objectives.

Timeline

This Rule Change Proposal will be progressed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The projected timelines for progressing this proposal are:



Call for submissions

The Rule Change Panel invites interested stakeholders to make submissions on this Rule Change Proposal. The submission period is 30 Business Days from the Rule Change Notice publication date. Submissions must be delivered to the RCP Secretariat by **5:00 PM** on **Friday, 20 April 2018**.

The Rule Change Panel prefers to receive submissions by email, using the submission form available at: https://www.erawa.com.au/rule-change-panel/make-a-rule-change-submission sent to rcp.secretariat@rcpwa.com.au.

Submissions may also be sent to the Rule Change Panel by post, addressed to:

Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

RCP | Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: **RC_2018_03**
Date received: **1 March 2018**

Change requested by:

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Address:	5/682 Murray St, West Perth WA 6005
Date submitted:	1 March 2018
Urgency:	High
Rule Change Proposal title:	Capacity Credit Allocation Methodology for Intermittent Generators
Market Rule(s) affected:	10.5.1, 11, Appendix 9

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (Market Rules) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: rcp.secretariat@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

Currently, Non-Scheduled Generators such as wind farms and solar farms are allocated Capacity Credits using the Relevant Level Methodology as set out in clause 4.11.2(b) and Appendix 9 of the Market Rules. Collgar Wind Farm considers the Relevant Level Methodology is flawed and discriminate against intermittent generation technologies as the approach appears arbitrary and overly conservative in allocating Capacity Credits to intermittent generators.

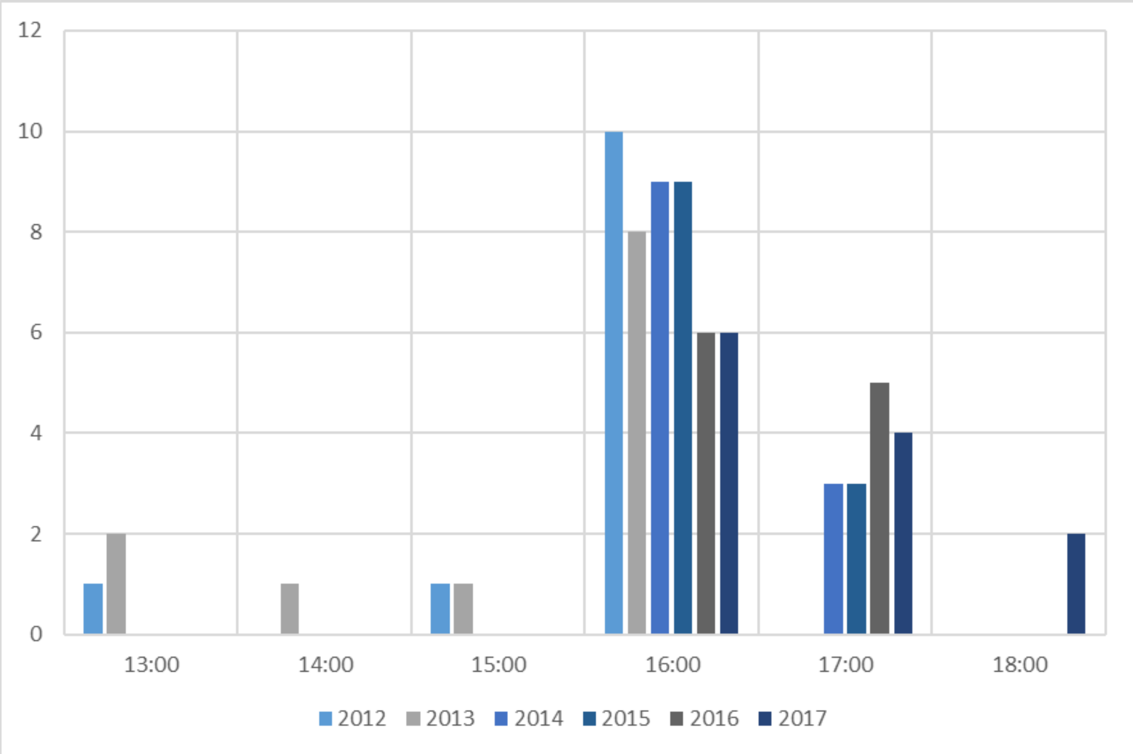
The current Relevant Level Methodology makes use of the concept of Load for Scheduled Generation (LSG) which is derived as the total metered load on the system less the metered output of all Non-Scheduled Generators. The current methodology uses the output of Non-Scheduled Generators during the 12 peak LSG Trading Intervals in each of the last 5 years as the basis for the Capacity Credit allocation to Non-Scheduled Generators.

Collgar Wind Farm was one of the many industry participants opposed to the introduction of the LSG concept with the implementation of Rule Change 2011 25 entitled “Calculation of the Capacity Value of Intermittent Generation – Methodology 1 (IMO)” (RC 2011 25) on 1 January 2012. One of our main concerns remain valid: The LSG concept does not provide a direct link between the requirement for capacity to meet system peak periods and the ability of capacity providers to make capacity available during these peak periods.

Market Customers are required to surrender Capacity Credits in proportion to their median load during the 12 peak intervals each year. These intervals are referred to as the Individual Reserve Capacity Requirement (IRCR) intervals and are made up by the 3 peak intervals on each of the 4 peak load days of the Hot Season (December to March). Scheduled Generators are allocated Capacity Credits based on their ability to sustain output during peak conditions as defined by the de-rated capacity of the generator at 41C, and this provides a good approximation to their ability to provide capacity during the IRCR intervals.

With the increasing penetration of rooftop Photo Voltaic (PV) systems installed behind the meter the traditional peak times in the middle of the day are being shifted to later periods in the day. This is illustrated in Figure 1, showing LSG intervals increasingly shifting to the later Trading Intervals in the day[1]. Some LSG intervals in recent years have even shifted out of the traditional peak period with LSG intervals occurring for example on 8 June 2016 and 12 July 2016. LSG intervals are no longer necessarily falling in similar periods to IRCR intervals and therefore do not represent a reasonable representation of the ability of intermittent generators to provide capacity support to the system during the true peak periods on the system when such support is of most value.

Figure 1: LSG intervals by time period 2012 - 2017



One of the stated objectives when introducing the LSG concept in the WEM Rules was to put in place a methodology that more accurately recognised the contribution of PV to overall system capacity. With LSG periods shifting to 5 pm and later, this will impact significantly in a negative direction on solar farms in particular, despite these facilities generally being available with high capacity factors during the traditional peak periods where the underlying "gross" demand on the system is at the highest.

Collgar Wind Farm believes that as a first step in rectifying the methodology for allocating Capacity Credits to intermittent generators the concept of LSG in the WEM Rules need to be removed and replaced with intervals selected from the actual system peak periods. This will provide a more direct link between the requirement for capacity in peak periods and the ability of intermittent generators to provide capacity during those periods of the highest demand on the system. Collgar Wind Farm considers this will be an important step in addressing discrimination against intermittent generation technologies.

Collgar Wind Farm is also of the view that further and more significant reform of the mechanism for allocating Capacity Credits may be required and would support a coordinated process to

[1] The trend for the actual peak Trading Intervals for the SWIS and therefore the IRCR intervals is similar in that they are generally shifting to later periods in the day.

do this. For example, we remain unconvinced as to the use of the Facility Adjustment Factors contained in Appendix 9. In the interest of expediency in rectifying the core of the issue (the use of the LSG concept) our proposal contained in this document represents a "small step" in the right direction and only addresses the selection of intervals that forms the basis for the assessment of the Relevant Level.

The proposal contained in this document should be progressed and implemented as soon as possible as we believe it represents a relatively easy and cost-effective way of immediately alleviating the situation and improve the ability to facilitate all Market Objectives, except for Market Objective (e), which we consider will not be impacted negatively or positively.

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2. Explain the reason for the degree of urgency:

Collgar Wind Farm believes this rule change proposal can be progressed using the normal rule change process.

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3. Provide any proposed specific changes to particular Market Rules: *(for clarity, please use the current wording of the rules and place a ~~strikethrough~~ where words are deleted and <u>underline</u> words added)*

Collgar Wind Farm proposes to remove the concept of LSG in determining the Relevant Level contained in Appendix 9. In place of the 60 LSG intervals that are currently made up from each of the 12 highest LSG intervals, from each of the last 5 years, and all occurring on separate days Collgar Wind Farm proposes that Load for Relevant Level (LRL) intervals be used and selected as follows: For each of the previous 5 years identify the 12 intervals with the highest aggregate demand on the system, with each of those 12 intervals occurring on separate days. The resulting 60 intervals will make up the data set upon which to assess the Relevant Level, which is the basis for allocation of Capacity Credits as per the Appendix 9 of the WEM Rules.

With the removal of the LSG concept it will also be necessary to make some flow on adjustments to the way that new facilities are treated compared to existing facilities.

The following amendments to the WEM Rules are proposed to affect the change:

Clause 10.5.1(x) amended as follows:

x. the following information identified for a Reserve Capacity Cycle under the Relevant Level Methodology—

1. the ~~Existing Facility~~ Load for ~~Scheduled Generation~~<u>Relevant Level</u> for each Trading Interval in the five year period determined under step 1(a) of the Relevant Level Methodology; and

2. the 12 Trading Intervals occurring on separate Trading Days with the highest ~~Existing Facility~~ Load for ~~Scheduled Generation~~<u>Relevant Level</u> for each 12 month period in the five year period; and

Definitions in Chapter 11 Glossary amended as follows:

~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level: Means the MWh quantity determined for a Trading Interval under step 7 of the Relevant Level Methodology.

~~**New Facility Load for Scheduled Generation**: Means, for a new or upgraded Facility that has applied to be assigned Certified Reserve Capacity under clause 4.11.2(b), the MWh quantity determined for a Trading Interval under step 11 of the Relevant Level Methodology for that Facility and the relevant Reserve Capacity Cycle.~~

Appendix 9 to be amended as follows:

Appendix 9: Relevant Level Determination

This Appendix presents the methodology for determining the Relevant Levels for Facilities that have applied for certification of Reserve Capacity under clause 4.11.2(b) for a given Reserve Capacity Cycle ("Candidate ~~Facility~~Facilities").

For the purposes of the Relevant Level determination in this Appendix 9:

- the full operation date of a Candidate Facility for the Reserve Capacity Cycle ("Full Operation Date") is:
  - the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service; or
  - the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise; and
- a Candidate Facility will be considered to be:
  - a new candidate Facility, if the five year period identified in step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility ("New Candidate Facility"); or
  - an existing Candidate Facility ("Existing Candidate Facility"), otherwise.

AEMO must perform the following steps to determine the Relevant Level for each Candidate Facility:

Determining ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level

Step 1: Identify:

(a) the five year period ending at 8:00 AM on 1 April of Capacity Year 1 of the relevant Reserve Capacity Cycle;

(b) any 12 month period, from 1 April to 31 March, occurring during the five year period identified in step 1(a), where the 12 Trading Intervals with the highest ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level in that 12 month period have not previously been determined under this Appendix 9; and

(c) any 12 month period, from 1 April to 31 March, occurring during the five year period identified in step 1(a), where the 12 Trading Intervals with the highest ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level in that 12 month period have previously been determined under this Appendix 9.

Step 2: Determine the quantity of electricity (in MWh) sent out by each Candidate Facility using Meter Data Submissions for each of the Trading Intervals in the period identified in step 1(b).

Step 3: For each Candidate Facility, identify any Trading Intervals in the period identified in step 1(b) where:

(a) the Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or

(b) the Facility, if in the Balancing Portfolio, was instructed by System Management to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or

(c) was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A.

Step 4: For each Candidate Facility and Trading Interval identified in step 3(a):

(a) identify the actual quantity as determined in step 2 if:

i. System Management has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the Power System Operation Procedure; and

ii. the revised estimate of the maximum quantity is lower than the actual quantity as determined in step 2;

(b) identify the actual quantity as determined in step 2 if:

i. step 4(a) does not apply; and

ii. the estimated maximum quantity determined by System Management under clause 7.13.1(eF) is lower than the actual quantity (as specified in a Meter Data Submission covering the Facility and the Trading Interval); and

(c) if steps 4(a) and (b) do not apply:

i. identify the revised estimate of the maximum quantity determined by System Management in accordance with the Power System Operation Procedure specified in clause 7.7.5A; or

ii. if there is no revised estimate, identify the estimate determined by System Management under clause 7.13.1(eF).

Step 5: For each Candidate Facility and Trading Interval identified in step 3(b) use:

(a) the estimate recorded by System Management under clause 7.13.1C(e); and

(b) the quantity determined for the Facility and Trading Interval in step 2,

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction to change its commitment or output during the Trading Interval.

Step 6: For each Candidate Facility and Trading Interval identified in step 3(c) use:

(a) the schedule of Consequential Outages determined by System Management under clause 7.13.1A;

(b) the quantity determined for the Facility and Trading Interval in step 2; and

(c) the information recorded by System Management under clause 7.13.1C(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been affected by the notified Consequential Outage during the Trading Interval.

Step 7: Determine for each Trading Interval in each 12 month period identified in step 1(b) the ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level (in MWh) as:

~~(~~Total_Generation + DSP_Reduction + Interruptible_Reduction + Involuntary_Reduction~~) – CF_Generation~~

where

Total_Generation is the total sent out generation of all Facilities, as determined from Meter Data Submissions;

DSP_Reduction is the total quantity by which all Demand Side Programmes reduced their consumption in response to a Dispatch Instruction, as determined under clause 6.17.6(c)(i);

Interruptible_Reduction is the total quantity by which all Interruptible Loads reduced their consumption in accordance with the terms of an Ancillary Service Contract, as recorded by System Management under clause 7.13.1C(c);

Involuntary_Reduction is the total quantity of energy not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b); and

~~CF_Generation is the total sent out generation of all Candidate Facilities, as determined in step 2 or estimated in steps 4, 5 or 6 as applicable.~~

Step 8: Determine for each 12 month period identified in step 1(b) the 12 Trading Intervals, occurring on separate Trading Days, with the highest ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level.

Step 9: Identify, for each 12 month period identified in step 1(c), the following:

(a) the ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level previously determined under this Appendix 9 for each Trading Interval in the 12 month period;

(b) subject to step 9A, the sent out generation (in MWh) for each Candidate Facility and for each Trading Interval in that 12 month period~~, where that sent out generation was used to determine the CF_Generation (which is one of the variables used to determine the Existing Facility Load for Scheduled Generation in step 7) for that Trading Interval~~; and

(c) the 12 Trading Intervals occurring on separate Trading Days that were previously determined to have the highest ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level in the 12 month period.

Step 9A: For the purposes of step 9(b), if:

(a) System Management has determined a revised estimate of the maximum quantity in accordance with the Power System Operation Procedure specified in clause 7.7.5A;

(b) the revised estimate relates to a Candidate Facility and a Trading Interval in a 12 month period identified in step 1(c); and

(c) AEMO determined the sent out generation for that Candidate Facility and for that Trading Interval in accordance with step 4 before it revised the estimate,

then AEMO must redetermine the sent out generation for that Candidate Facility and that Trading Interval in accordance with step 4.

Determining ~~New Facility Load for Scheduled~~Sent Out Generation for New Candiadate Facilities

Step 10: For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a) that falls before 8:00AM on the Full Operation Date for the Facility, an estimate of the quantity of energy (in MWh) that would have been sent out by the Facility in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Facility under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

~~Step11: For each New Candidate Facility determine, for each Trading Interval in the period identified in step 1(a), the New Facility Load for Scheduled Generation (in MWh) as:~~

~~(a) if the Trading Interval falls before 8:00 AM on the Full Operation Date for the Facility:~~

~~EFLSG + Actual_CF_Generation – Estimated_CF_Generation~~

~~where~~

~~EFLSG is the Existing Facility Load for Scheduled Generation for the Trading Interval, determined in step 7 or identified in step 9(a) as applicable;~~

~~Actual_CF_Generation is the sent out generation of the New Candidate Facility for the Trading Interval, as identified in step 9(b), determined in step 2 or estimated in steps 4, 5 or 6 as applicable; and~~

~~Estimated_CF_Generation is the quantity determined for the New Candidate Facility and the Trading Interval in step 10;~~

~~or~~

~~(b) the Existing Facility Load for Scheduled Generation for the Trading Interval, otherwise.~~

~~Step 12: For each New Candidate Facility determine, for each 12 month period identified in step 1(a), the 12 Trading Intervals, occurring on separate Trading Days, with the highest New Facility Load for Scheduled Generation.~~

Step11: [Blank]

Step 12: [Blank]

Determining the Facility Average Performance Level

Step 13: For each ~~Existing~~ Candidate Facility, determine the 60 quantities comprising:

(a) the MWh quantities determined in step 2 or estimated in steps 4, 5, 6 or ~~6~~10 as applicable for each of the Trading Intervals determined in step 8, multiplied by 2 to convert to units of MW; and

(b) the MWh quantities determined in step 9(b) for each of the Trading Intervals identified in step 9(c), multiplied by 2 to convert to units of MW.

~~Step 14: For each New Candidate Facility, determine the 60 quantities comprising:~~

~~(a) the MWh quantities identified in step 9(b), determined in step 2 or estimated in steps 4, 5 or 6 as applicable for each of the Trading Intervals identified in step 12 that fall after 8:00 AM on the Full Operation Date for the Facility, multiplied by 2 to convert to units of MW; and~~

~~(b) the MWh quantities determined in step 10 for each of the Trading Intervals identified in step 12 that fall before 8:00 AM on the Full Operation Date of the Facility, multiplied by 2 to convert to units of MW.~~

Step 14: [Blank]

Step 15: Determine the average performance level (in MW) for each Candidate Facility f ("Facility Average Performance Level") as the mean of the 60 quantities determined for Facility f in step 13~~ or step 14 as applicable.~~.

Determine the Facility Adjustment Factor

Step 16: Determine the variance (in MW) for each Candidate Facility f ("Facility Variance") as the variance of the MW quantities determined for Facility f in step 13~~ or step 14 as applicable~~.

Step17: Determine the facility adjustment factor (in MW) for each Candidate Facility f ("Facility Adjustment Factor") in accordance with the following formula:

Facility Adjustment Factor = min (G x Facility Variance (f), Facility Average Performance Level (f) /3 + K x Facility Variance (f))

Where

G = K + U/Facility Average Performance Level (f)

K is determined in accordance with the following table:

Reserve Capacity Cycle	Capacity Year	K value
2012	2014/15	0.001
2013	2015/16	0.002
2014	2016/17	0.003
2015 onwards	From 2017/18 onwards	To be determined by AEMO in accordance with clause 4.11.3B.

U is determined in accordance with the following table:

Reserve Capacity Cycle	Capacity Year	U
2012	2014/15	0.211
2013	2015/16	0.422
2014	2016/17	0.635
2015 onwards	From 2017/18 onwards	To be determined by AEMO in accordance with clause 4.11.3B.

Determining the Relevant Level for a Facility

Step 18: Determine the Relevant Level for each Candidate Facility f (in MW) in accordance with the following formula:

Relevant Level (f) = max(0, Facility Average Performance Level (f) - Facility Adjustment Factor (f))

Publication of information

Step 19: Publish on the Market Web Site by 1 June of Year 1 of the relevant Reserve Capacity Cycle on a provisional basis:

(a) a forecast of the Trading Intervals that may be identified in step 8; and

(b) a forecast of the ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level quantities that may be determined in step 7.

Step 20: Publish on the Market Web Site within three Business Days after the date specified in clause 4.1.11 (as modified or extended) for the relevant Reserve Capacity Cycle:

(a) the Trading Intervals identified in step 8; and

(b) the ~~Existing Facility~~ Load for ~~Scheduled Generation~~Relevant Level quantities determined in step 7.

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4. Describe how the proposed rule change would allow the Market Rules to better address the Wholesale Market Objectives:

The proposed amendments to the Market Rules will improve facilitation of all Market Objectives, except for Market Objective (e). Market Objective (e) will not be negatively impacted.

Further detail for the assessment against each Market Objective is available in the sections below.

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

The proposed approach of using Trading Intervals from true system peak conditions in place of the LSG intervals is likely to more accurately reflect the ability of Facilities assessed using the Relevant Level Methodology to provide capacity support to the system at times of the highest demand for capacity. The change will remove an unnecessary conservative bias against technologies that are assessed using the Relevant Level Methodology. This should result (based on estimates using data for 2012 – 2017) in about a 25% increase in capacity credits allocated to wind farms[2], corresponding to an efficiency for the Wholesale Electricity Market and its customers of about 20 MW. At the current capacity credit price of $111,752 that represents a potential efficiency saving in excess of $2.2 million per year by avoiding investment in additional capacity that can readily be served by existing intermittent generators.

As the proposed changes will more closely align the assessment intervals for allocating Capacity Credits with the intervals when that capacity is required we are also of the view that

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[2] The analysis is based on data from the large wind farms on the system only (EDWFMAN_WF1, ALBANY_WF1, ALINTA_WWF, GRASMERE_WF1, MWF_MUMBIDA_WF1, INVESTEC_COLLGAR_WF1). Data on solar farms was not available in sufficient detail for our analysis.

system security and reliability should not suffer any negative consequences. Conservativism is retained in the assessment of Capacity Credit allocations via the Relevant Level Methodology by retaining the adjustment factors.

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

Collgar Wind Farm considers the proposed changes will remove an element of discrimination against intermittent technologies and thereby providing a more level playing field for generators using different technology options. This should encourage competition in generation, including from potential new investors. We do not consider it likely that the proposed changes will impact retail competition in any form.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

As already outlined, the proposed amendments will remove discrimination that currently exist within the Market Rules in relation to the application of the Relevant Level Methodology and provide a better and more direct link between intermittent generators' ability to provide capacity during times of the greatest need (system peak events). The proposed amendments will not impact conventional, dispatchable technologies as these will continue to be assessed based on their ability to provide capacity in 41C degree conditions.

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

The long-term cost of supplying electricity to customers will reduce with the proposed amendments as a higher, and more accurate level of capacity credits is likely to be allocated to intermittent generators. This will immediately reduce the need for additional investment in generation as the current fleet of intermittent generators will be able to serve a higher proportion of the load during system peak events compared to the level reflected in their current Capacity Credit allocations.

Having in place a more accurate methodology for assessing the ability of intermittent generators to contribute to system peak events is also likely to lead to more efficient investment decisions in new generation projects. Ensuring long-term investments are made with as accurate information as possible is likely to further drive competition to the long-term benefit of customers in the South West Interconnected System.

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Collgar Wind Farm considers there will be no discernible impact on facilitating achievement of Market Objective (e).

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5. Provide any identifiable costs and benefits of the change:

Collgar Wind Farm will not incur any costs of its own to implement this change. Given the relatively minimal change required it is believed that any system costs for AEMO should also be minimal.
