Draft Rule Change Report: Implementation of 30-minute Balancing Gate Closure (RC_2017_02)

Standard Rule Change Process

18 May 2020

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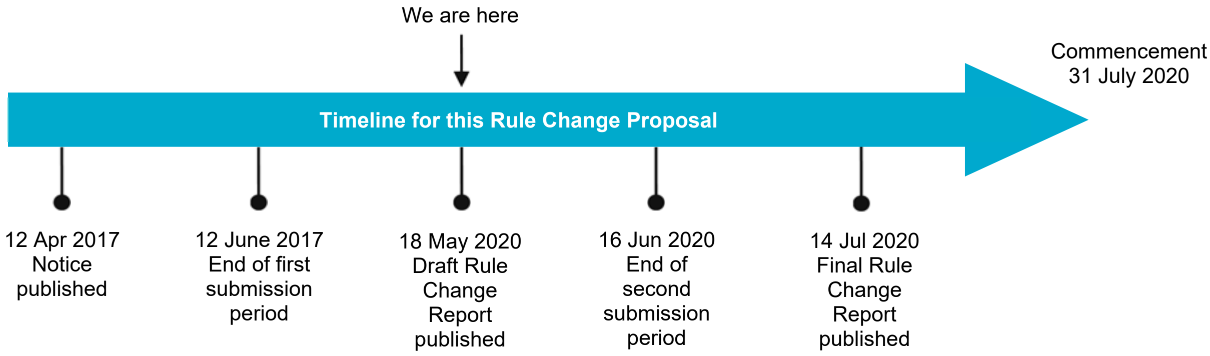
1. Rule Change Process and Timeline

On 4 April 2017, Perth Energy submitted a Rule Change Proposal titled "Implementation of 30-minute Balancing Gate Closure" (RC_2017_02) to the Rule Change Panel. The Rule Change Proposal aimed to reduce the length of the Balancing Gate Closure (**BGC**) period from two hours to no more than 30 minutes.

The Rule Change Proposal was progressed using the Standard Rule Change Process, described in section 2.7 of the Market Rules. The timeframes for the first submission period and the preparation of the Draft Rule Change Report were extended by the Rule Change Panel under clause 2.5.10. Details of these extensions are available on the Rule Change Panel's website. The key dates for progressing this Rule Change Proposal, as amended in the extension notices, are:



This Draft Rule Change Report is drafted on the basis that the reader has read all the related documents, including the Rule Change Proposal and the first period submissions. All documents related to the Rule Change Proposal can be found on the Rule Change Panel's website at https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2017_02.

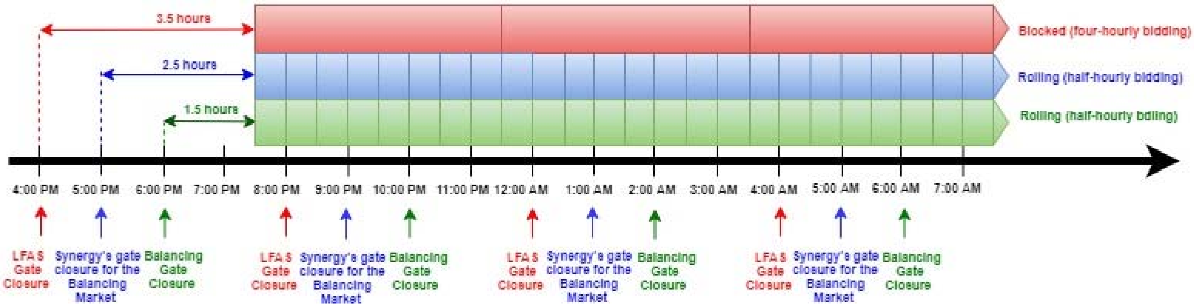
2. The Rule Change Panel's Draft Decision

The Rule Change Panel's proposed decision is to accept the Rule Change Proposal in a modified form, as outlined in section 6 of this Draft Rule Change Report and summarised as follows:

- move from a 120-minute rolling BGC to a 90-minute rolling BGC;
- move from a 240-minute gate closure for Synergy for the Balancing Market, with a 6-hour bidding block, to a 150-minute rolling gate closure for Synergy for the Balancing Market;
- move from a 300-minute LFAS Gate Closure, with a 6-hour bidding block, to a 210-minute LFAS Gate Closure, with a 4-hour bidding block; and
- move from a 600-minute LFAS Gate Closure for Synergy, with a 6-hour bidding block, to a 210-minute LFAS Gate Closure, with a 4-hour bidding block.

Figure 1 illustrates the Rule Change Panel's proposed decision.

Figure 1: Illustration of the Rule Change Panel's Decision



The LFAS Horizon is a four-hour period commencing at 4:00 PM, 8:00 PM, 12:00 AM, 4:00 AM or 8:00 AM. The LFAS Gate Closure is the point in time which is two hours before the BGC and one hour ahead of Synergy's gate closure for the Balancing Market.

2.1 Reason for the Rule Change Panel's Draft Decision

The Rule Change Panel has made its draft decision on the basis that the Amending Rules, as modified in this Draft Rule Change Report:

- will allow Market Participants, including Synergy, to delay making trading decisions in both the Balancing and LFAS markets until closer to real time, when more accurate forecasts of the Load for Scheduled Generation are available for each Trading Interval;
- will reduce risk and allow Market Participants to respond to changing market conditions, promoting economic efficiency and minimising the long-term cost of electricity supplied to consumers;
- will allow Synergy to provide more accurate price signals to the market;
- will reduce the asymmetry in access to accurate information for making trading decisions between IPPs and Synergy in the Balancing Market, thereby increasing competition;
- will maintain a one-hour gap between the gate closure for Synergy and IPPs to protect IPPs from infeasible dispatch, but will minimise the gap to maximise the benefits of a shorter gate closure for Synergy;
- will align the requirements in the Market Rules with practice in the LFAS Market, ensuring clarity for Market Participants and reducing the risk of non-compliance;
- are consistent with changes in market design to accommodate an increasing penetration of renewable technologies observed in Western Australia and in other jurisdictions;
- will better achieve Wholesale Market Objectives (a), (b), (c) and (d); and will be consistent with Wholesale Market Objective (e);
- can be implemented at minimal cost and with minimal changes to AEMO's systems, and is not expected to significantly increase constraint compensation (pending feedback from AEMO on the cost and practicality of the changes to the LFAS Gate Closure); and
- were generally supported in feedback from Market Advisory Committee (**MAC**) members and attendees at the MAC workshops held on 6 September 2019 and 18 October 2019.

The Rule Change Panel rejects changing the BGC to 30 minutes because it is infeasible under the current market design, given the timeframe of AEMO's processes and the 15-minute start up period for open cycle gas turbines.

The Rule Change Panel rejects changing the BGC to 60 minutes because, if such a change was implemented:

- AEMO has indicated that it would implement an automated linear ramping process that would be costly and take a long time to develop, and would increase constraint payments; and
- Synergy would increasingly be required to offset the aggregate ramp rate of IPPs within the Trading Interval but may not be fully remunerated for this service and is likely to be less physically able to provide this service in the future.

The Rule Change Panel rejects the proposed additional options for enhancing the information used in trading decisions[1] because the costs to implement these options as advised by AEMO would likely be greater than the benefits advised by MAC members.

The analysis supporting the Rule Change Panel's decision is provided in section 6 of this report.

2.2 Proposed Commencement

The Amending Rules are proposed to commence at **8:00 AM** on **Friday, 31 July 2020**. The commencement date is provisional and may change in the Final Rule Change Report.

3. Call for Second Round Submissions

The Rule Change Panel invites interested stakeholders to make submissions providing feedback on any aspects of the Draft Rule Change Report.

The submission period is 20 Business Days from the Draft Rule Change Report publication date. Submissions must be delivered to the RCP Secretariat by **5:00 PM on Tuesday 16 June 2020**.

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 support@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

[1] The additional options for enhancing the information used in trading decisions were:

1. increasing the frequency of the BMO calculation to every ten-minutes for the whole Balancing Horizon;
2. calculation of the Forecast BMO every ten minutes but only for the Trading Interval for which gate closure is about to occur; and
3. publication of a 5-minute balancing load forecasts in a new report.

4. Proposed Amendments

4.1 The Rule Change Proposal

The Rule Change Proposal seeks to change the BGC from the current two-hour window to no more than 30 minutes before the relevant Trading Interval. Perth Energy considers that the increased percentage of Non-Scheduled Generation and small scale solar in the WA energy sector has led to more dynamic market conditions, such that load forecasts can vary dramatically between the finalisation of Balancing Submissions and commencement of the Trading Interval.

Perth Energy contends that such variation results in inaccurate price signals, which can lead to a less responsive and less competitive market, and consequently the current two-hour BGC is no longer sufficient to maintain an efficient and equitable market.

Perth Energy considers that moving the BGC to 30 minutes before a Trading Interval, will provide Market Participants greater opportunity to respond to forecast changes and bid as accurately as possible. Perth Energy notes that shortening the time between gate closure and trading will not improve the forecast itself, but it will reduce the margin for error, which it considers is a practical and inexpensive first step to improve the economic efficiency of the market.

Perth Energy argues that, after more than four years of market operation with a BGC of two hours, Market Participants and System Management have demonstrated the capability to operate with a small bidding window in a near real-time market, and it is therefore reasonable to consider shortening the gate closure period.

4.2 The Rule Change Panel's Initial Assessment of the Proposal

The Rule Change Panel decided to progress the Rule Change Proposal on the basis that its preliminary assessment indicated that the proposal is consistent with the Wholesale Market Objectives.

5. Consultation

5.1 Market Advisory Committee Consultation before the Close of the First Submission Period

5.1.1 1 May 2017 MAC Meeting

The Rule Change Proposal was discussed by the MAC at its meeting on 1 May 2017.

Mr Patrick Peake (Perth Energy) gave a presentation that focussed on the benefits of moving from a 2-hour to a 30-minute gate closure.

AEMO also gave a presentation on the Rule Change Proposal, which comprised two parts:

- Mr Martin Maticka discussed the effects of the proposal on market systems and outcomes; and
- Mr Dean Sharafi described some of the challenges System Management would face with a reduced gate closure period.

All three presentations are available on the Rule Change Panel's website: https://www.erawa.com.au/rule-change-panel/market-advisory-committee/market-advisory-committee-meetings.

The following is an extract of the Minutes from the relevant parts of the MAC.

5.1.1.1 The Costs and Benefits of Shortening the Balancing Gate Closure

Mr Maticka advised that reconfiguring the market systems to support a 30-minute gate closure would be simple and inexpensive but a reduction below 30 minutes would require much more significant changes to market systems, which were designed around a 30-minute processing cycle. Mr Maticka warned that there was also a risk of added rework costs if such changes were to be made before AEMO completed the extraction of its systems from Western Power.

Mr Will Bargmann (Synergy) considered the proposal would create a wealth transfer from Synergy to IPPs, as it worsened an economic inefficiency caused by disparity of information available to IPPs compared with Synergy. Mr Bargmann explained that the proposed change to a 90-minute gate closure was a 75% improvement for IPPs but proportionally only a small change for Synergy. Mr Peake disagreed with Mr Bargmann, noting that if all the parties involved were bidding at their short run marginal costs (**SRMC**) then the shifting of dispatch from Synergy to IPPs should be economically efficient and benefit customers.

Ms Elizabeth Aitken (Perth Energy) and Mr Andrew Stevens (Energy Made Clean) both noted that Synergy could remove Facilities from the Balancing Portfolio and offer them into the Balancing Market with the same gate closure as IPPs. Mr Bargmann responded that the pros and cons of Facility bidding was a bigger market issue. Mr Stevens noted the Balancing Portfolio provides several advantages to Synergy over other participants (e.g. IPPs are unable to see Facility bid data for the Synergy plant).

5.1.1.2 The Aggregate Ramping of IPPs

Mr Sharafi noted that due to current market arrangements, IPPs are dispatched at their maximum ramp rates at the start of a Trading Interval, and this results in combined IPP ramp rates that are sometimes 3-4 times higher than the ramp rate of the Balancing Portfolio. Mr Sharafi explained that System Management has about 110 minutes after IPP gate closure to plan and execute the manual positioning of Synergy plant to compensate for IPP movements, changes in demand and Intermittent Generation fluctuations, while preserving the required levels of Load Following and contingency reserves.

Mr Sharafi considered that if this period was reduced to 30 minutes the dispatch would become unmanageable for System Management under the current market structures. However, if the dispatch systems and Market Rules were changed to allow for the linear ramping of IPP Facilities, then System Management would be able to manage a 30-minute gate closure.

Mr Sharafi considered that the changes to allow for linear ramping would need to include amendments to the current constraint payment calculation in the Market Rules, to prevent the payment of constrained off compensation to Market Generators who were dispatched at less than the maximum ramp rate provided in their Balancing Submission.

Mr Stevens queried the extent of the IPP ramping problem and considered that if ramp rates were only a rare problem (e.g. once every three months) then this might be acceptable. Mr Sharafi responded that once every three months or even once a year would be too frequent if it results in load rejection or a major blackout. Mr Stevens considered that System Management would constrain IPP units on or off in these situations rather than risking Power System Security to follow the merit order.

5.1.1.3 Analysis of the Benefits of the Proposal

Mr Bargmann stressed the need for a cost/benefit analysis to be undertaken on the proposal, taking into account the wealth transfer from Synergy to IPPs created by the proposal. Mr Shane Cremin (Market Generators) suggested that even if, in the short term, the net benefits of the proposal were limited, there is a need to consider the benefits in the context of a broader, long-term (10-year) plan to transition to a more flexible energy system. Mr Bargmann agreed with Mr Cremin, noting that it would be very short-sighted for a business case not to consider the long-term benefits and costs.

There was some discussion about how the costs of any additional constraint payments would compare with the efficiency benefits of shorter gate closure. Mr Stevens did not expect the impact of the problem situations to be anything like the efficiency savings of 30-minute gate closure.

5.1.1.4 Flexible Ramping of IPP Facilities

Ms Laidlaw asked how well the relevant IPPs could physically control the ramp rates of their Facilities, both during the process of synchronising and reaching minimum stable levels and during subsequent movements. Mr Peake advised that Perth Energy's Facility's minimum stable level was effectively 0 MW, although they would prefer to reach a minimum output level of around 35-55 MW quickly for efficiency reasons. Mr Peake advised that once the Facility reaches this level, it is very flexible in terms of ramp rates.

Ms Wendy Ng (Market Generators) considered that control software changes may be required for some Facilities to support flexible ramping. Mr Stevens suggested the costs of such changes may be minor compared with the potential economic benefits of a shorter gate closure.

5.1.1.5 Forecasting Intermittent Generation

Mr Maticka noted that at the time of gate closure, the wind forecast provided by Market Generators through their Balancing Submissions was usually more accurate than the persistence wind forecast, but when it came closer to the actual Trading Interval the persistence wind forecast became notably more accurate than the Balancing Submissions.

Mr Sharafi noted the detrimental effect of an increasing solar PV penetration on load forecast accuracy. There was some discussion about the method used by System Management to measure and estimate solar PV output.

5.1.1.6 Other Options for Shortening the Balancing Gate Closure

Ms Laidlaw and Mr Stevens asked whether there was any scope to reduce the gate closure to somewhere between 30 minutes and 2 hours (e.g. 1 hour). Mr Sharafi replied that the controllers had advised him that in some cases even a 2-hour gate closure can be challenging.

Ms Aitken asked if the Real Time Dispatch Engine (**RTDE**) could support a 5-minute dispatch cycle. Mr Sharafi considered that a shorter dispatch cycle would not fix the constraint payment problem.

5.1.1.7 Synergy's Gate Closure Arrangements

Mr Bargmann requested that the Rule Change Panel consider changes to Synergy's gate closure times, as suggested in the IMO's Pre-Rule Change Proposal: Improvements to the Energy Market (PRC_2014_01).[2]

Ms Laidlaw sought the views of other MAC members on further changes to Synergy's gate closure arrangements. Mr Peake considered that if reducing Synergy's gate closure resulted in Ancillary Service cost savings that flowed through to the market, then Perth Energy would be strongly in favour of the change.

5.1.1.8 Market Evolution and Reform

Mr Sharafi's presentation highlighted an extreme example of a 657 MW dispatch requirement in the market and indicated that challenging situations such as this were not rare and occurred every one or two shifts. Mr Stevens noted recent forecasts indicating that by 2040, 40% of Western Australian generation would come from renewable sources.

There was some discussion about the broader changes to the energy market proposed by the Energy Market Reform (**EMR**) program (including Facility bidding, co-optimisation and 5-minute dispatch as well as a reduced gate closure), and how the timing and direction of these changes affects this Rule Change Proposal. Further details of this MAC meeting are available in the MAC meeting papers and minutes are available on the Rule Change Panel's website.

5.1.2 14 June 2017 MAC Meeting

Ms Laura Koziol and Ms Jenny Laidlaw (RCP Support) noted that the first submission period for the Rule Change Proposal had closed and that RCP Support was reviewing the

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2 Pre-Rule Change Proposal: Improvements to the Energy Market (PRC_2014_01), developed by the Independent Market Operator (IMO) in early 2014, proposed to reduce the BGC to 30-minutes, replace the 6-hour block-based gate closure for the LFAS Market with a rolling gate closure (2 hours for the Balancing Portfolio and 90 minutes for other Facilities), and change Balancing Market gate closure for the Balancing Portfolio to a rolling 60-minutes. However, a Rule Change Proposal was not submitted to or by the IMO for consideration prior to advice from the Minister for Energy to defer the timeframes for existing Rule Change Proposals until an independent Rule Change Panel was established to undertake rule making functions on 3 April 2017.

submissions and would be contacting AEMO to clarify some aspects of its submission and to discuss various options for addressing the aggregate ramp issue.

There was discussion about whether the planned implementation of the Generator Interim Access (**GIA**) arrangements would affect the time needed by controllers to prepare for a Trading Interval after BGC. In response to a question from Ms Wendy Ng, Mr Sharafi confirmed that the GIA implementation would not hold up the progression of the Rule Change Proposal.

5.2 Submissions Received during the First Submission Period

The first submission period for this Rule Change Proposal was held between 12 April 2017 and 12 June 2017. The Rule Change Panel received submissions from AEMO, Alinta Energy (**Alinta**), Bluewaters, Community Electricity, Perth Energy and Synergy. Perth Energy also made an out of session submission on 28 May 2018. A summary of the main aspects raised in these submissions is set out below.

Although the Rule Change Panel has summarised the submissions in accordance with clause 2.7.7 of the Market Rules, the Rule Change Panel has reviewed the submissions in their entirety and considered each matter raised by the Rule Participants in making its draft decision on this Rule Change Proposal.

5.2.1 AEMO's Advice on Gate Closure Options for the Wholesale Electricity Market

5.2.1.1 Hybrid Design of the Market

AEMO considered that the current hybrid design of the Balancing Market, with System Management retaining responsibility for scheduling and dispatching generation Facilities within the Balancing Portfolio, constrains the extent to which the BGC can be shifted closer to real time.

AEMO explained that the Wholesale Electricity Market (**WEM**) differs from other electricity markets because AEMO's controllers have an incomplete generation dispatch schedule at the point of BGC, with information only about the dispatch of energy and Load Following Ancillary Service (**LFAS**) from IPP Facilities, which frequently provide less than half of the WEM's required amounts of energy and LFAS. AEMO considered that after BGC, AEMO's controllers must:

- fill in the gaps, analysing the Forecast Balancing Merit Order (**BMO**) and scheduling the various Balancing Portfolio Facilities to achieve energy dispatch consistent with the BMO; and
- ensure adequate Ancillary Service availability to manage system frequency and maintain Power System Security, with the Balancing Portfolio providing the majority of the LFAS, Spinning Reserve Service and Load Rejection Reserve (**LRR**) Service requirements.

5.2.1.2 The Effect of the Aggregate Ramp Issue on Ancillary Service Quantities

AEMO explained that the aggregate ramp issue can create challenges for AEMO's generation controllers, requiring preparatory scheduling of the Balancing Portfolio to balance the ramping without materially eroding Ancillary Service quantities.[3]

AEMO considered that, by default, any ramping mismatch within the Trading Interval is assumed to be absorbed by LFAS.

5.2.1.3 Timeframe of System Management's Processes

AEMO explained that, during the period between receipt of the final BMO (a few minutes after the BGC) and the start of the Trading Interval, where a forecast change of at least 50 MW is required in Balancing Portfolio generation (which, according to AEMO, occurs in about 40% of Trading Intervals), the controllers:

- take a few minutes to perform an initial assessment of the current operating levels and ramping capability of the Facilities within the Balancing Portfolio, comparing these with the BMO and system security assessments to determine whether a detailed assessment will be required;
- take approximately 15 to 20 minutes (for an experienced controller) to perform a detailed assessment to plan material changes to the Balancing Portfolio dispatch before the start of the Trading Interval, such as starting or stopping a generating unit or a coal mill,[4] to achieve the required energy movement, aggregate ramp rate and/or preserve or restore system security; and
- issue the relevant instructions to Synergy power station operators to give effect to the chosen Balancing Portfolio Dispatch Plan, with longer lead time actions, such as starting or stopping coal mills and slow ramping of coal units, collectively taking 45 to 60 minutes, and the start-up of open cycle gas turbines, taking up to 15 minutes.

AEMO therefore considered that the total time requirement for these steps can exceed 80 minutes when larger movements of the Balancing Portfolio Facilities are required in advance of the Trading Interval and can exceed 90 minutes in extreme cases.

AEMO noted that in parallel to the steps described above, the generation controller routinely undertakes system security assessments when significant changes in system dynamics occur, to identify any potential contingency violations and assess alternative generation scenarios. According to AEMO, this takes approximately 25 minutes, after which any contingencies identified may require a detailed assessment of the ability of the system to accommodate changes in dispatch.

5.2.1.4 AEMO's Advice on Gate Closure Options

Based on the information set out above, AEMO advised that:

- a 90-minute BGC is likely to be achievable without any added changes to the design of the Balancing Market, although this may result in some increases to constrained on or constrained off compensation, as movements of the Balancing Portfolio to address the aggregate ramp issue may not be completed prior to the start of the Trading Interval;

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3 As explained at the 1 May 17 MAC meeting, the aggregate ramp issue is created when multiple Facilities are ramping in the same direction from the start of a Trading Interval and this creates an aggregate ramp movement that may exceed the underlying movement in demand in the early minutes of the Trading Interval.

4 A coal mill is used to crush (pulverise) pieces of coal into fine particles before it is fed into a boiler, to ensure efficient combustion.

- a 60-minute BGC would require some complementary changes to dispatch and settlement arrangements to reduce the scope of preparatory steps, and the time needed to execute them; and
- a 30-minute BGC is infeasible with the current hybrid design of the Balancing Market and in the absence of more fundamental reform of the WEM.

5.2.2 General Feedback on the Proposal

AEMO noted that it supports a shortened gate closure, or removal of gate closure, but considered that this could best be achieved as part of the full set of WEM reforms proposed by the Public Utilities Office (**PUO**) – now Energy Policy WA (**EPWA**) – rather than in isolation of other changes to the market design.

Alinta, Bluewaters and Community Electricity all supported the proposal to reduce the BGC to 30 minutes before a Trading Interval. In providing their support, both Community Electricity and Alinta acknowledged System Management's advice that the gate closure must be at least 30 minutes ahead of real time to accommodate existing processes and requires conducive changes to the Market Rules governing generator ramping.

Community Electricity considered that it is a matter of public record that the two-hour ahead load forecasts in combination with two-hour ahead gate closure for IPPs (and six hours for Synergy) are dysfunctional. Community Electricity explained that fast-response units either miss opportunities to run (elevating prices and missing revenue) or run when not needed (depressing prices and under recovering costs).

Alinta considered that the current gate closure times limit the flexibility of generators to take efficient actions in response to changing circumstances in the two hours leading up to real time. Alinta noted that the gate closure times constrain both IPP's and Synergy's Facilities from responding dynamically to changing environmental and commercial conditions.

Perth Energy expressed concerns about the effect of the GIA tool on pricing, noting in particular, that each GIA generator would have its Price-Quantity Pairs inserted into the bid stack after BGC. Perth Energy considered that this meant that the forecast quantities and prices of all GIA generators would be absent from the market, making outcomes highly volatile and significantly increasing risk for non-GIA participants by preventing accurate price signals.

Perth Energy therefore suggested amending the Rule Change Proposal to remove the BGC altogether, allowing Market Participants to respond to changes in quantities and prices until the commencement of the relevant Trading Interval, including from GIA generators.

In support of this, Perth Energy noted that System Management had accepted the high-level design of Western Power's GIA solution at that time, including the inherent need for its operators to continually assess and re-dispatch Facilities every few minutes. Perth Energy considered therefore, that System Management could accommodate short-term changes in dispatch such as those required for a shortened gate closure or removal of gate closure, despite System Management voicing its reluctance to do so.

However, on 28 May 2018, Perth Energy made a second, out of session submission, in which it acknowledged that moving to a 30-minute gate closure was most likely contingent on Synergy moving to Facility dispatch from the current portfolio dispatch. Perth Energy noted that it would reluctantly, support a 60-minute gate closure if the preconditions for a 30-minute gate closure could not be met. Perth Energy stressed, however, that this would deliver less benefits to AEMO, generators and customers, and should be an interim move.

Synergy did not support the Rule Change Proposal. Synergy considered that there is no basis for the current differential gate closures, which it described as discriminatory, economically inefficient and inconsistent with the Market Objectives. Synergy further considered that the differential gate closures create inefficient economic signals, allow shadow pricing by other generators and discourage competition, driving up the long-term cost of electricity.

5.2.3 Benefits of the Proposal

Feedback on the benefits of the proposal was mixed. Community Electricity considered that reducing the BGC would enable generators to delay their dispatch decision as late as practical, improving the accuracy of expected outcomes.

Similarly, Bluewaters, AEMO and Alinta considered that the proposal would provide participants with a greater opportunity to respond to forecast changes and enable more accurate trading decisions. Alinta identified several other benefits of reducing the BGC, including:

- assisting short term participation and risk management in the physical electricity market;
- enabling greater certainty for participants about their own fuel and plant status when making final submissions; and
- reducing reporting, compliance, and administration costs.

AEMO agreed with Perth Energy's observations that a later BGC would reflect the increasing dynamism of the WEM, promote competition, be consistent with technological developments, and achieve improvements in forecast accuracy, resulting in cost savings for consumers.

However, AEMO observed that, in its proposal, Perth Energy's analysis of forecasting accuracy included basic statistics of forecast variation (maxima, minima and averages) based on the current gate closure time and did not assess the accuracy of forecasts at a 30-minute BGC. Following AEMO's own analysis of forecasting accuracy, presented at the 1 May 2017 MAC meeting, AEMO concluded that the improvements may not be as large as suggested by Perth Energy.

AEMO was also concerned that shortening the gate closure beyond 90 minutes in the absence of other changes to the market design may lead to unintended consequences, such as increased instances of constrained on or constrained off compensation or declarations of High-Risk Operating States.

AEMO and Alinta both considered that shortening the gate closure would reduce the current delay when a generating unit returns to service following maintenance, with low cost generation displacing higher cost generation, and would reduce the Balancing Price. As noted by AEMO, the PUO estimated a recurring benefit of $300,000 per annum, if the BGC was moved to 30 minutes before the start of the interval, in its *Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*. AEMO suggested that a shift to a 90-minute BGC could realise approximately one-third of this benefit.

In contrast, Synergy considered the PUO's claim of a recurring benefit of $300,000 per annum to be 'incredibly optimistic,' as a Facility operator will know well in advance of two hours when its Facility will be able to return from a Forced Outage. Therefore, Synergy considered that the current BGC is sufficiently close to real time to realise most of the benefits claimed by the PUO.

Synergy further contended that there is no evidence in the proposal that the gains in economic efficiencies will outweigh the economic inefficiencies, as the analysis is based on the assumption that all changes in the Balancing Price between the forecast price and the Final Price will be avoided with a shorter BGC. Synergy considered that the results of AEMO's analysis of forecast accuracy, presented to the MAC on 1 May 2017, indicated that the majority of changes in Balancing Price (and quantity) are due to forecast error, which is not known until real time, and thus, irrespective of a shorter gate closer, changes to the Balancing Price cannot be avoided.

Synergy warned that the proposal would incentivise and increase the ability for IPPs controlling Facilities with flexible capacity to bid in a manner that maximises their profits by shadow pricing against Synergy's locked in prices. This outcome, according to Synergy, would further decouple the Balancing Price from the economically efficient price, decreasing competition between the Balancing Portfolio and IPP generators, leading to higher costs for consumers.

5.2.4 Possible Solutions to Address the Aggregate Ramp Issue

5.2.4.1 Use of Existing Processes to address the Aggregate Ramp Issue

Alinta considered that the security implications of a 30-minute gate closure period should be manageable and that it appears possible to reduce the gate closure without significant detrimental effects. In support of this, Alinta explained that even in the current circumstances, there can be late bona fide changes to offers close to real time and System Management manages this risk effectively. Alinta noted further that, if required, System Management can call a high, or emergency risk operating state to resolve any Power System Security and/or reliability issues.

5.2.4.2 Linear Ramping

Alinta considered that requiring linear ramping via the Market Rules would be problematic and cost Alinta in the order of $200,000 per unit to implement, as it requires control system and governor changes.[5] Further, Alinta considered that the amendments may only be required for a short period of time, as it is unlikely that these changes would be required to support the market reform currently being contemplated. Accordingly, Alinta considered that it would not support changes to the dispatch systems and Market Rules to require linear ramping of IPP Facilities.

However, Alinta noted there could be other software changes that could be made, outside the governor, that could provide a solution to the IPP ramp rate issue and allow Facilities to support flexible ramping, in a significantly more cost-effective manner.

5.2.4.3 Staggered Ramping

Alinta explained that the RTDE currently provides Dispatch Instructions on a 10-minute basis and suggested that consideration be given to dispatching some Facilities 10 or even twenty minutes into the Trading Interval. Alinta considered that this would alleviate System Management's issues with IPPs being dispatched at their maximum ramp rates at the start of a Trading Interval, resulting in combined IPP ramp rates that are sometimes three to four times higher than the ramp rate of the Balancing Portfolio.

5 A governor is fitted to a generating unit to control power output and to help regulate network frequency.

5.2.4.4 Avoidance of the Aggregate Ramp Issue

Alinta considered that the Rule Change Panel could, in its Draft Decision, look to amend the Rule Change Proposal to reduce the length of the BGC period from two hours to no more than one hour. Alinta suggested that this may provide a balanced solution, which addresses the trade-off between capturing the benefits of flexibility and managing system security. Alinta considered that this solution would also allow a move to a 30-minute (or less) gate closure, as time and circumstances allow.

5.2.4.5 A Sculpted Load Following Ancillary Service

Synergy noted that in its presentation to the MAC, to address the aggregate ramp issue, AEMO stated that its controllers have to start positioning Facilities up to 110 minutes out from dispatch. Given that System Management does not have a final BMO until just prior to the start of a Trading Interval, Synergy reasoned that the only Facilities AEMO could use to do this would be from the Balancing Portfolio. Synergy contended therefore that AEMO appeared to be acknowledging that it uses the Balancing Portfolio to provide 'free LFAS.' Synergy highlighted its concern that there is a significant risk that this would increase if the Rule Change Proposal is progressed in its current form.

Synergy also considered that:

- AEMO's ability to use the formal LFAS Requirement (cf. free LFAS) will be reduced if the BGC is reduced to 30 minutes or less; and
- to the extent that it is required to address large movements of Facilities, to maintain the system in a secure and reliable manner, AEMO will have to:
    1. increase the formal LFAS Requirement for all Trading Intervals where there is a possibility of significant changes in the output of multiple Facilities (i.e. pay for significantly more LFAS and leave that LFAS idle most of the time);
    2. increase the availability and dispatch of ultra-flexible plant within the Balancing Portfolio;
    3. increase the likelihood of insufficient LFAS being available when needed; or
    4. adopt a sculpted LFAS Requirement.[6]

Synergy considered that outcomes 1 to 3 are economically inefficient and/or pose an increased and unacceptable risk to Power System Security and reliability. Synergy understood that the current Market Rules already allow for a sculpted LFAS Requirement but noted that it appears that AEMO chooses to use the Balancing Portfolio to provide the extra LFAS instead. Therefore, Synergy considered that the Rule Change Panel should amend the Market Rules to expressly require AEMO to use a sculpted LFAS Requirement, and not to use the Balancing Portfolio in a manner different to other Facilities.

[6] Sculpting the LFAS Requirement involves adjusting the LFAS Requirement to reflect that the system needs it to be set at a more granular level than annually. For example, with an increasing penetration of solar PV, supply in the SWIS is more variable in the day than at night, leading to different LFAS Requirements at different times of the day. In this case, sculpting the LFAS Requirement means having more than one LFAS Requirement based on the time of the day (i.e. reflecting that overnight there is no variability from PV systems). See page 16 of AEMO's Ancillary Services Report for the WEM 2019 https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf.

5.2.5 Amendments to Synergy's Gate Closure for the Balancing Market and the LFAS Gate Closure

AEMO considered that market efficiency would be improved when all Market Participants are able to make operational decisions with the most accurate available information. Therefore, AEMO suggested that the Rule Change Panel consider the potential for amendments to the LFAS Gate Closure and the deadlines for Synergy in submitting updated Balancing Portfolio Supply Curves. AEMO noted that it did not foresee any additional operational challenges to those it had already mentioned if these timeframes were shortened proportionally.

Perth Energy noted that it had undertaken further analysis of the causes of significant variability in market outcomes over time, particularly price, and determined that movements in the Synergy Portfolio were a key contributor to this variability. Accordingly, Perth Energy suggested further amendment of the Rule Change Proposal to allow Synergy to make rolling forecasts rather than fixed-point, and to reduce Synergy's Portfolio gate times commensurately with those proposed for other participants (e.g. from six-hours to two-hours).

Perth Energy reasoned that this would allow Synergy to more actively manage its Facilities, minimise volatility in the market and improve overall market efficiency. Perth Energy also noted that Synergy could remove Facilities from the portfolio to achieve later gate closure, and therefore that implementation of the Proposal should not be unduly deferred for this reason.

Bluewaters also proposed that the Rule Change Panel consider whether the reduced gate closure should also be applied to Synergy but considered that the implications of Synergy's market power needs to be assessed.

Alinta noted that under the current WEM design, Synergy continues to be subject to differential treatment (i.e. it can bid as a portfolio in the energy markets), but it has fewer opportunities to revise its Balancing Portfolio Submissions, which are locked in ahead of IPP gate closure. Alinta noted its preference that Synergy be required to make submissions for each of its Facilities so that it is dispatched on the same basis as other participants' Facilities as soon as practicable.

Alinta understood that the current arrangements were originally needed to facilitate a smooth transition to the new market arrangements without risking system security and reliability, and to address concerns around market power. Nevertheless, Alinta considered that it is not in the market's interest for Synergy to base its bids on potentially highly inaccurate information, or for its gate closure restrictions to adversely affect other market outcomes.

Alinta recommended changing the BGC for the Balancing Portfolio to a rolling gate closure. However, Alinta advised that:

- this should be subject to a cost-benefit analysis, and that the solution selected should not present an impediment to or delay a move to full Facility bidding; and
- if the gate closure for the Balancing Portfolio is moved to a rolling gate closure, it is important that IPPs are still able to update their Balancing and LFAS Submissions having seen the final position for the Synergy Portfolio, which should be allowed for when setting the gate closure timeframes.

Synergy considered that, unless the Rule Change Panel modifies the proposal to create the same gate closure times for the Balancing Portfolio as for other Market Participants, the Rule Change Panel should reject the proposal. Synergy requested that the Rule Change Panel use this opportunity to create an even playing field between Synergy and IPPs and allow the market to realise the significant benefits associated with long-term price signals that reflect the cost of electricity production.

Synergy contended that, under the proposal, the information available to Synergy and IPPs would become more asymmetric, as the proposed reduction in BGC would reduce the current time lag for IPP Facility Balancing Submissions by 75%, but only reduce the time lag for the Balancing Portfolio by a maximum of 37.5%, and a minimum of 15% (due to Synergy's requirement to bid in six-hour blocks tied to the LFAS Gate Closure).[7] According to Synergy, this would increase the risk of economically inefficient wealth transfers from Synergy to IPPs, with no consequential benefit to consumers.

Synergy considered that the differential gate closures may have originally been introduced as a quid pro quo to offset Synergy's benefits associated with its ability to return Facilities from Outage materially earlier than other Market Participants. However, Synergy reasoned that, with a move to a 30-minute BGC for IPP Facilities, IPPs and Synergy would be able to return Facilities from Forced Outage at effectively the same time, removing any discrimination.

Synergy considered that the Market Rules that require all Market Participants to offer at SRMC where the behaviour relates to Market Power are sufficient to mitigate against market power abuses and result in economically efficient prices and outcomes.

5.2.6 Other Options for Enhancing Information used in Trading Decisions

Bluewaters considered that, even with the shorter gate closure, accuracy of trading decisions may be compromised due to the potential volatility and unpredictability of Intermittent Generators' outputs. Bluewaters noted that the current market arrangement does not provide accurate forecasts of Intermittent Generators' outputs. Bluewaters proposed to require AEMO to publish this information on a timely basis to help address the issue and further enhance the effectiveness of the shortened gate closure in achieving more accurate trading decisions.

Alinta recommended that consideration should be given to allowing (but not requiring) Market Generators to update their wind forecasts after gate closure.

5.2.7 Submitting Parties' Assessment of whether the Rule Change Proposal would better achieve the Wholesale Market Objectives

The assessment by submitting parties of whether the current Rule Change Proposal would better achieve the Wholesale Market Objectives is summarised in Table 1.

7 Synergy refers to clause 7A.2.9(d) of the Market Rules.

Table 1: Submitting Parties' Assessment of whether the Rule Change Proposal would better Achieve the Wholesale Market Objectives

Submitter	Wholesale Market Objective Assessment
AEMO	AEMO considers that later BGC would be likely to improve the economic efficiency of the Balancing Market, promote competition and remove barriers to dispatch of fast-response technologies. However, subject to the extent to which BGC is shifted later, AEMO is concerned that impediments in the hybrid design of the Balancing Market may reduce, and potentially negate, these benefits. AEMO considers that a shift to 90-minute BGC is achievable with low implementation cost and risk and would better facilitate the achievement of Wholesale Market Objectives (a), (b), (c) and (d). However, AEMO advises that the cost and risk could increase if BGC is shifted to 60 minutes or 30 minutes in the absence of further change to the design of the Balancing Market. Consequently, the extent to which a gate closure change to 60 minutes or less, in isolation, would improve the achievement of the Wholesale Market Objectives is unclear.
Alinta	The current gate closure times limit the flexibility of generators to take efficient actions in response to changing circumstances. The gate closure times constrain generators from responding dynamically to changing environmental and commercial conditions, meaning that higher cost plant may be dispatched when lower cost plant should be. Allowing Market Participants to base submissions on more up to date information is expected to better promote the economic efficiency of the physical markets (Wholesale Market Objective (a)).
Bluewaters	Submission did not refer to the Wholesale Market Objectives.
Community Electricity	Submission did not refer to the Wholesale Market Objectives.
Perth Energy	Perth Energy referred to its assessment of whether its proposed change will better facilitate the achievement of the Wholesale Market Objectives from its proposal. Perth Energy considered that the reduction of the time frames for BGC as further amended in its submission would allow the Market Rules to better achieve Wholesale Market Objectives (a), (b), (c) and (d).[8] Perth Energy consider that the proposed change will: • enable more active participation for those Market Participants wanting to respond to price signals in the WEM, and ultimately increase competition and reduce prices • increase transparency and provide greater opportunities for participation of generators in real-time, in response to more accurate price signals • increase the dynamism of the market, ensuring that those Facilities best placed to meet the energy requirements are dispatched, increasing the

8 As outlined in sections 5.2.2 and 5.2.5 of this report, Perth Energy requested to remove the BGC altogether and to treat Synergy commensurately with other participants.

Submitter	Wholesale Market Objective Assessment
	efficiency of the market, and ultimately driving lower prices for end-use customers.

Synergy	Synergy considered that the Rule Change Proposal will:
	• Materially decrease the economic efficient supply of electricity and, to the extent that risks to system security and reliability are not increased, decrease the economic efficient supply of LFAS (an electricity related service) to the South West Interconnected System (**SWIS**). Specifically, Synergy contends that the Rule Change Proposal will result in this unacceptable outcome because:
	  o the increases in information asymmetry between IPPs and Synergy will result in increased shadow pricing and therefore less efficient balancing market prices. This will have a significant negative effect on the long-term ability of the Balancing Market to signal efficient entry and exit of Facilities and energy consumption; and
	  o the change will require AEMO to have more Facilities sitting idle to provide LFAS.
	• Materially discourage competition amongst generators because it will facilitate and incentivise IPP Facilities to shadow price the Balancing Portfolio and decrease Synergy's ability to counter such shadow pricing.
	• Over-reward flexible fast-start Facilities and therefore incentivise an economically inefficient amount of entry of that type of Facility into the Market. Such an inefficient investment signal for one type of Facility will result in uneconomic under-investment in other Facility types. These positive biases to one type of Facility will effectively result in the Rule Change Proposal discriminating against all other types of Facility.
	• Materially, negatively affect the economic efficiency of the long-term price signals in the Balancing Market and increase LFAS costs, both of which will materially increase the long-term cost of electricity to consumers.
	• To the extent that the Rule Change Proposal causes inefficient price signals that do not match actual costs, decrease the incentive to efficiently manage the amount of electricity consumption and the time when electricity is consumed.
	Synergy considered that the proposal would generally promote the Wholesale Market Objectives if it was amended to:
	• allow the BGC to apply to the Balancing Portfolio; and
	• require AEMO to ‘sculpt’ LFAS Requirements, while expressly prohibiting the use of the Balancing Portfolio to effectively provide ‘free’ LFAS.

5.3 The Rule Change Panel’s Response to Submissions Received during the First Submission Period

The Rule Change Panel’s response to each of the specific issues raised in the first submission period is presented in Appendix A of this report. See also sections 6.1 and 6.2 of this report for a general discussion of the Rule Change Proposal, which addresses the main issues raised in submissions and the Rule Change Panel's response to these issues.

5.4 MAC Consultation following the close of the First Submission Period

5.4.1 12 July 2017 MAC Meeting

The Chair gave an update on the progress made by RCP Support on the Rule Change Proposal. The presentation is available on the Rule Change Panel's website. The following is an extract of the Minutes of the MAC meeting.

5.4.1.1 Forecasting Intermittent Generation

There was discussion about why the wind forecasts provided by Market Generators in their Balancing Submissions did not noticeably improve in accuracy over time. Mr Cremin and Mr Mark Katsikandarakis (AEMO) considered it likely that Market Generators were providing the best information available to them, given the relative infrequency with which their own forecasts were updated.

There was also discussion about options to improve the quality of wind forecasts in the BMO, including the use of persistence forecasts after a certain point in time and the implementation of a centralised wind forecasting system such as AEMO's Australian Wind Energy Forecasting System (AWEFS).

5.4.1.2 Effect of a Reduced Gate Closure on Setting the LFAS Requirement

Mrs Jacinda Papps (Alinta) asked whether the proposal would affect AEMO's current practice (as set out in its most recent Ancillary Services Report) to set the LFAS Requirement at ±72 MW, regardless of the actual quantity used.

Mr Sharafi noted that the report reflected the current arrangements, including the gate closure time and considered that if, due to a shorter gate closure, System Management did not have time to move Synergy's slower machines to prepare for the ramping of IPP Facilities, it might seek to increase the LFAS Requirement.

5.4.1.3 Synergy's Gate Closure

The Chair noted that Synergy had requested the same gate closure time as IPPs, and that RCP Support had found the potential efficiency benefits of allowing participants to respond to later, more accurate forecasts, would also apply to the Balancing Portfolio.

Mr Peake suggested that alternatively Synergy's gate closure could be reduced by an amount that kept the current proportional information asymmetry, so that Synergy was not made any worse off by the change.

5.4.1.4 Use of the Balancing Portfolio to Offset the Aggregate Ramp Issue

Mr Ben Williams (Synergy) observed that System Management always used the Balancing Portfolio to compensate for the fast ramping of other Facilities, even on those occasions (about 15% of the time) when the Balancing Portfolio was not the marginal Facility. Mr Williams considered that System Management was required under the Market Rules to issue a Dispatch Advisory whenever it dispatched the Balancing Portfolio Out of Merit, and its failure to do so in these situations suggested that the Balancing Portfolio movements should be regarded as LFAS rather than Out of Merit dispatch.

There was considerable discussion about how these movements should be categorised (Balancing vs LFAS), how Synergy is currently compensated for them, the technical limitations on System Management's dispatch options and the potential costs of amending AEMO's dispatch systems to dispatch marginal IPPs to address ramp rate discrepancies.

Mr Peake queried how Synergy's coal units were affected, as he assumed that gas units were setting the current high Balancing Prices. There was some discussion about how and why the ramping of IPP Facilities affected Synergy's coal plant.

5.4.1.5 Other Solutions for Addressing the Aggregate Ramp Issue

Mr Peake noted that Perth Energy preferred other options to linear ramping for addressing the aggregate ramp issue, including staggering the dispatch of Facilities, as linear ramping could require operation of its plant at inefficient output levels for extended periods.

Mr Sharafi considered that the purpose of LFAS is not really to manage ramping discrepancies, but to manage fluctuations in load and unscheduled generation. The Chair agreed that ideally the dispatch process should manage the ramping discrepancies.

5.4.1.6 Costs and Benefits given Market Reform

Mr Bargmann noted the expected short payback period for any solution was based on the assumption that the WEM would move to a NEM-like spot market in the next few years. Mr Bargmann considered there was some uncertainty about this assumption, given the current focus within the State Government on capital expenditure, and that there would need to be a real focus on the benefits and costs of the wider reforms for them to proceed in the current circumstances.

Both Mr Stevens and Mr Martin noted that the Energy Market Reform (**EMR**) had already articulated the benefits and costs of these changes. Mr Peake considered that a long-term solution being further away would provide additional justification for trying to take whatever quick wins were possible through this Rule Change Proposal. The Chair noted that if the payback period were to become indefinite, then this could bring several previously discounted options back into consideration (e.g. more material changes to the RTDE and settlement calculations).

Mr Williams expressed concern that any option that delayed the upwards or downwards ramping of units (e.g. the implementation of linear ramping) might create inefficiencies that counter some of the economic benefits of a shorter gate closure.

Mr Gaston considered that economic efficiency should be the prime objective of the market and if there is even a miniscule amount of additional economic efficiency to be gained from the proposal then the market should be striving to implement it.

5.4.2 13 June 2018 MAC Meeting

Mr Peake gave a brief overview of Perth Energy's request to increase the urgency rating of the Rule Change Proposal from Medium to High. A copy of Perth Energy's submission is available in the meeting papers on the Panel's website.

Mr Mehdi Toufan (System Management) reiterated the comments made in AEMO's first period submission that AEMO would be able to reduce the BGC to 90 minutes using its current systems and processes, but would require major changes, including Facility bidding, to support 60 minutes, and the implementation of co-optimisation to support 30 minutes.

Mr Toufan presented a graph comparing System Management's demand forecasting errors with the forecasting errors of Intermittent Generators (for the period 14 May to 10 June 2018). A copy of the graph is available on the Panel's website.

Mr Toufan suggested that gate closure was not the only issue and there was an opportunity to consider how to make Market Participant's forecasts more accurate. In response to a question from Ms Erin Stone (Market Customers), Mr Toufan advised that the limitations were systems-related and also related to System Management's ability to manage the power system. Ms Stone suggested that options to resolve any technical issues should also be identified and considered.

The Chair gave an overview of the analyses RCP Support might need to undertake to assess the net benefits of the Rule Change Proposal. Mr Bargmann considered that the Chair's comments indicated that the Rule Change Proposal should remain a Medium urgency Rule Change Proposal, on the basis that the net benefits may be large, but this required more analysis. Mr Bargmann considered that the proposed amendments would introduce several inefficiencies that require further analysis.

Ms Laidlaw noted that RCP Support would also need to consider what gate closure times should apply to the Balancing Portfolio. Mr Stevens considered that Synergy could choose to bid on an individual Facility basis at any time. Mr Williams disagreed, based on advice provided by AEMO that it would be difficult to remove coal plant from the Balancing Portfolio, if not impossible.

There was some discussion about the role of the Balancing Portfolio in real-time dispatch, the relationship between gate closure and efficient dispatch of the Balancing Portfolio, and options to avoid excessive constrained off compensation under a reduced gate closure scenario.

5.4.3 12 September 2018 MAC Meeting

The Chair noted that AEMO discussed the Rule Change Proposal (Implementation of 30-Minute BGC) and the possibility of moving to a 90-minute BGC at its WA Electricity Consultative Forum meeting on 21 August 2018. The Chair and Ms Laidlaw noted that for RCP Support to recommend accepting the Rule Change Proposal in an amended form, it would need to look at the costs and benefits of all of the options, including a 60-minute BGC and changes to Synergy's gate closure.

Mr Peake indicated that he supported the change to a 90-minute BGC if it could be done cheaply. Mr Maticka replied that AEMO's first period submission confirmed this would be the case. Mr Sharafi reiterated that AEMO could move to a 90-minute BGC without system changes if that was what the MAC wanted it to do and that AEMO could also look at providing forecasts with more frequency or in a shorter timeframe than the gate closure.

Mr Cremin considered that if the move to 90 minutes could be done simply then it should be progressed as quickly as possible. The Chair noted that the Panel could not just decide to implement a 90-minute BGC because it was easy and reiterated the need to consider all the options.

There was some discussion about whether a separate Rule Change Proposal could be used to implement a 90-minute BGC in the short term without affecting consideration of a shorter BGC under the Rule Change Proposal.

Mr Maticka suggested that the Market Rules could be amended to reduce the lower limit on BGC from two hours to 30 minutes. This would allow AEMO to implement a 90-minute BGC in the short term, and then be able to reduce the BGC further at its discretion. Mr Stevens agreed this would be a simple rule change.

Mr Gaston also agreed but considered the upper limit (currently six hours) should also be reduced. Mr Gaston noted that AEMO's alternative proposal did not address Synergy's concerns about its gate closure times. Mr Maticka replied that AEMO was neutral on this matter.

Mr Bargmann indicated that Synergy would continue to raise its concerns in submissions on the Rule Change Proposal and any alternative proposal. There was some discussion about how Synergy's gate closure times should be affected by a change to the BGC.

5.5 Public Forums and Workshops

RCP Support held two MAC workshops for this Rule Change Proposal. Workshop minutes, slides and handouts are available from the Rule Change Panel's website.

The first workshop was held on 6 September 2019. The aim of the workshop was to consider the main issues associated with the proposal and the options to address them, including:

1. comparison of reduced BGC options, and how to address the existing aggregate ramp issue;
2. options for amending Synergy's gate closure;
3. options for amending the LFAS Gate Closure;
4. a strawman proposal;
5. enhancement of information used in trading decisions; and
6. how to quantify the possible effects of the proposal.

Given the level of discussion and a two-hour timeframe, only the first four topics were covered in this workshop. A second workshop was then scheduled for 18 October 2019 to:

1. provide a brief overview of the main outcomes from the first workshop;
2. update Market Participants on outcomes since the first workshop;
3. address the remaining two topics:
    a. enhancement of information used in trading decisions;
    b. how to quantify the possible effects of the proposal; and
4. consider the next steps in the rule change process.

The following sections provide extracts of the minutes of the two workshops, summarising the key aspects of the discussion on the Rule Change Proposal. Further details, including workshop discussion notes, presentations and minutes, are available on the Rule Change Panel's website.

5.5.1 6 September 2019 MAC Workshop

5.5.1.1 Movement of Synergy's Coal Plants to Address the Aggregate Ramp of IPPs

Ms Natalie Robins questioned whether it was right to not reduce the BGC because of constraints on the operation of the market imposed by slow ramping coal plants. Mr Brad Huppatz (Synergy) considered that the coal ramp rate would be more of an issue at a 60-

minute BGC than at a 90-minute BGC. However, Mr Huppatz questioned whether there is an issue because of slow coal ramp rates or because Synergy's Balancing Portfolio is asked to ramp at a higher ramp rate than Synergy has bid in its submission.

Mr Huppatz considered that the issue arises due to a combination of the Synergy Balancing Portfolio operating at its minimum to provide the energy and Ancillary Services that they have cleared for, and its balancing capabilities being used to accommodate the ramp rates, not clearing the load following.

Mr Huppatz further explained that when Synergy is not marginal, they must back their coal plant down in the interval so that gas plant can respond and then bring them back up to a net zero position. Mr Huppatz considered that Synergy does not have the ability to respond and it is not viable for Synergy to move again, when it is at its minimum and has zero clearing volumes.

Mr Huppatz also considered that the market should move to accommodate the ramp in this situation and not be cross subsidized by Synergy, and that Market Participants should see the costs that are involved and look to minimise the total costs.

5.5.1.2 The use of LFAS to Address Instructed Fluctuations in Scheduled Generation

Mr Schubert questioned whether Spinning Reserve and LRR are constraining System Management's ability to use the Balancing Portfolio for LFAS and to address the aggregate ramp issue. Mr Sharafi acknowledged that the way System Management dispatches Synergy's Balancing Portfolio makes balancing and LFAS a bit mixed, and that System Management uses some LRR but considered that the focus should be on LFAS and how it is used to enable the market.

Mr Sharafi considered that, while the market is designed to use LFAS to address the aggregate ramp issue, the use of LFAS as a means of facilitating the market was a mistake in the market design, and it should only be used to balance changes in supply and demand in real time.

Mr Fairclough explained that the Market Rules require System Management to set the LFAS Requirement in a way that does not include instructed deviations from the ramping of Scheduled Generators. Mr Fairclough considered that the effectiveness of LFAS is reduced if it is used to address aggregate ramping or an instructed issue (i.e., an issue due to the dispatch of Scheduled Generators) at any point in time, and that the environment is changing such that the need for LFAS has increased and there is no longer as much flexibility.

Ms Laidlaw noted that the LFAS Requirement had never been set according to the Market Rules because there would never be enough. Ms Laidlaw considered that, when explaining how the RTDE works, it had been acknowledged from the start of the Balancing Market up until last week that load following would account for the difference when someone ramped faster than System Management would like because of how the RTDE and the Theoretical Energy Schedule (**TES**) work. Ms Laidlaw questioned whether the change in approach was due to an event, a degeneration in performance, an increased security risk, or whether System Management was running out of LFAS.

Mr Sharafi noted that recently, there were more instances of sudden changes in the system, such as when the frequency went to 52 Hz because a cloud front came and disappeared in a very short period, requiring 400 MW of ramp, and causing one Facility to trip on over frequency. Mr Fairclough agreed that uninstructed events (i.e. from unscheduled, Intermittent Generators) that disrupt Power System Security are happening more frequently and with greater magnitude but noted that System Management had not yet undertaken an analysis to show this.

Ms Laidlaw questioned whether AEMO's concern with including instructed fluctuations in the LFAS Requirement was that it might be breaching the Rules. Mr Fairclough questioned whether, if AEMO decided to include instructed output fluctuations in the LFAS Requirement, even though this is not in the rules, it would be efficient for the LFAS Requirement to be a lot more than it currently is. Ms Robins noted that LFAS had been used to address this issue in the past. Mr Fairclough considered that AEMO had more LFAS available in the past. Mr Sharafi explained that if there is an imbalance, the LFAS resolves the issue because of Automatic Generation Control (**AGC**).[9]

Ms Robins noted that the Annual Ancillary Services Report for 2019 presents a figure that says that frequency is maintained 99.998% of the time and questioned how close the market is to affecting that figure, based on what AEMO had said today. Mr Sharafi considered that the performance of frequency relates to LFAS to some extent but it also relates to other things like the response of the generators in the system (such as droop control), so a direct connection cannot be made between frequency performance and LFAS.

Mr Daniel Kurz questioned whether the 28 August 2019 change to the LFAS quantities were incorporated into AEMO's current views or whether that changed the dynamic even further. Mr Maticka and Mr Huppatz considered that increasing the LFAS limit would make it more difficult to manage the situation, by effectively removing the Facilities that are providing Ancillary Services from the Balancing Portfolio and thereby constraining the ramp rate that can be achieved.

Mr Patrick Peake considered that Perth Energy would like to see the gate closure as short as possible, but noted that it is aware of the significant issues faced by Synergy and System Management, so it would be reluctant to see the BGC pushed beyond what can be accommodated on a regular basis and under difficult situations. Mr Peake did not want to be in a position where System Management cannot organise itself within 60 or 90 minutes.

5.5.1.3 AEMO's Presentation on Aggregate Ramping Impacts on the Market

Mr Fairclough gave a presentation at the workshop outlining aggregate ramping impacts on the market and AEMO's proposed solution. Discussion in relation to each slide is set out below.[10]

Slide 3 – Mr Fairclough explained that, to respond to the aggregate ramping of IPPs in a normal operating state, AEMO can:

1. displace the Balancing Portfolio to offset it, if it is in the interval and the Balancing Portfolio is available to move within the interval;
2. dispatch the Balancing Portfolio in advance of the interval to reduce the impact and duration on use of LFAS Facilities; and
3. constrain IPP Facilities.

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9 AGC is the mechanism to provide a signal for both Automatic Balancing and Load Following Services. AGC is actively controlling the Facility when providing LFAS. See https://www.aemo.com.au/-/media/files/electricity/wem/security_and_reliability/ancillary-services/2018/abc-and-agc-requirements-sept-2018.pdf?la=en&hash=DF420D332F1552755E73C8A258D962F0

10 AEMO's slides for the 6 September 2019 MAC workshop are available from the Rule Change Panel's website at https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2017_02.

Mr Fairclough explained that with option 2, AEMO rearranges the position of coal and gas within the Balancing Portfolio so that it has a faster ramp rate than it would otherwise have during that Trading Interval, and it can move upward or downwards, or sometimes upwards and downwards, as required in that interval. Mr Fairclough considered that a move to a 60-minute BGC will preclude option 2, which would limit AEMO to either dispatching the Balancing Portfolio to offset the aggregate ramping of IPPs within the interval or constraining IPPs.

Mr Fairclough noted that up to now, AEMO has used the ramp rates specified in Balancing Submissions and only varies the ramp rates as a last resort, when there is a High-Risk Operating State, because doing so will result in constrained off payments.

Ms Laidlaw noted that the difference between the BGC options is that the advanced dispatch option is available for a 90-minute BGC but not for a 60-minute BGC and considered that, in a situation where Synergy has not got anything more to give, AEMO would have nothing left to shift around and it would not matter what the BGC was.

Ms Laidlaw further considered that there is an equity issue when AEMO advance dispatches some units to increase Synergy's ramp rate to higher than 15 MW/minute, as AEMO is moving Synergy above what it puts in its Balancing Submissions and Synergy is not being compensated for providing the additional ramp. Ms Laidlaw considered that the shifting around of Synergy's dispatch arrangement to provide additional ramp sounds like load following.

Mr Huppatz noted that Synergy is not always marginal and clearing for Ancillary Services. Mr Huppatz considered that he was not sure how the ramp rate minimum comes in, because if Synergy has cleared at minus $1000/MWh, it is not expecting to move. Synergy might not have the down ramp at that point, because it cannot go lower, and it's not expected to, and is still compliant. Ms Laidlaw considered that it sounded as if the advanced dispatch would not work in these situations and questioned whether the number of these situations is growing.

Mr Huppatz considered the number is growing and noted that there will be circumstances where, because of increasing the Ancillary Service cap, regardless of the 90-minutes, Synergy will not be able to provide the necessary ramp. In the past, there were higher loads, and Synergy was not at the floor, so AEMO could move its plant around to do that.

Slide four – Mr Fairclough presented a chart illustrating the effect on the Balancing Portfolio when one IPP ramps up and another ramps down at a different ramp rate. Mr Fairclough noted that the Balancing Portfolio is used where possible to allow the market to function and that there are occasions within the interval when AEMO has no other tools to ensure a good outcome, so it moves the Balancing Portfolio up and down, but still meets the required outcome at the end of the interval.

Slides five and six – Mr Fairclough presented charts showing the Balancing Portfolio's ramp up and ramp down capabilities (respectively) over time for the periods July to December 2012, July to December 2018, and January to June 2019.

Mr Fairclough explained that AEMO excluded any machines that were providing LFAS when it considered the capability of the Balancing Portfolio, as these machines cannot respond to an unscheduled movement if they are responding to a scheduled movement. This limited the Balancing Portfolio ramp rate, so it was often easy for scheduled non-Synergy movements to exceed the Balancing Portfolio ramp rate, leading to the aggregate ramping issue. A Facility was also excluded from the analysis if it was operating near its maximum or minimum so that it did not have the ability to move to the necessary ramp rate in the next minute.

According to Mr Fairclough, the charts showed that:

- The Balancing Portfolio has a ramp rate less than 20 MW/minute in about 20% of the Trading Intervals, during which the Balancing Portfolio may have insufficient ramp up capability.
- The Balancing Portfolio has a ramp rate less than 20 MW/minute in about 40% of the Trading Intervals, during which the Balancing Portfolio may have insufficient ramp down capability.
- The ramp rate for the Balancing Portfolio varies substantially from year-to-year.

Ms Laidlaw noted that Synergy's Balancing Submissions normally have a 15 MW/minute ramp rate and questioned how often the ramp rate was below this value. Mr Fairclough explained that it is virtually always greater than 15 MW/minute if every Facility in the Balancing Portfolio is considered, but not if LFAS Facilities are excluded.

Ms Laidlaw considered that the dispatch mechanism dispatches other people up or down to certain levels based on the assumption that Synergy can ramp at 15 MW/minute, and part of why the other participants get sent long distances is because the RTDE thinks that it has something (i.e. Synergy) that can go the other way. Ms Laidlaw questioned whether, if Synergy did not have 15 MW/minute, AEMO would use LFAS to pick that up. Mr Fairclough confirmed that this would be the case.

Mr Huppatz noted that Synergy had moved from clearing 70 MW of LFAS to zero.
Ms Laidlaw clarified that the Balancing Portfolio provides a balancing function, including a rebalancing at 10 and 20 minutes notionally, as well as providing LFAS and Spinning Reserve.

Slide 7 – Mr Fairclough highlighted differences between January and February of 2019 in the ramp up and ramp down rates of the Portfolio. Mr Fairclough noted that the participation of the Balancing Portfolio in the LFAS market changed significantly at the start of February, such that there was an increase in AEMO's ability to use the Balancing Portfolio for intra-interval balancing. Mr Fairclough considered that the ramp rate had also varied over time due to changes over the years in the total quantity that is being cleared by the Balancing Portfolio. Mr Fairclough noted that in 2019, AEMO is faced with:

- Downward ramp less than 20 MW/minute about 38% of the time and less than 10 MW/minute about 3% of the time; and
- Upward ramp less than 20 MW/minute about 25% of the time and less than 10 MW/minute about 2% of the time.

5.5.1.4 AEMO's Proposed Linear Ramping Solution

Mr Fairclough noted that AEMO's proposed solution to address the aggregate ramp issue is to implement linear ramping. Mr Fairclough explained that to implement linear ramping, when the BMO finishes,[11] AEMO will assess the forecast ramping capability of the Balancing Portfolio, demand and other factors; and if the aggregate ramp requirement exceeds the capability of the Balancing Portfolio, then AEMO will set the ramp rates to linear.

AEMO explained that to do this, it will issue every non-Synergy Facility a Dispatch Instruction to go to a point at the end of the interval via a ramp rate determined by AEMO. The ramp rates in the Dispatch Instructions for non-Synergy Facilities may be less than the Facilities' Ramp Rate Limits and AEMO will calculate them by taking the change in quantity over the

11 That is, when the Balancing Merit Order has been calculated for a Trading Interval after the relevant BGC.

interval and dividing it by the number of minutes left in the interval. AEMO will then average the solution so that the resulting ramp rates do not have decimals. Finally, to match the linear ramping of the non-Synergy Facilities, AEMO will also linear ramp the Balancing Portfolio in the opposite direction.

Mr Fairclough considered that the aggregate ramp issue arises because generators ramp at different rates to how the load is moving and that, with linear ramping, there still could be mismatches if the Balancing Portfolio does not ramp at its expected ramp rate, but they should net out in most cases and there will be no aggregate ramp issue.

Mr Fairclough noted that AEMO had reviewed the Market Rules and concluded it can do linear ramping now, without the dispatch being Out of Merit. However, any change to the ramp rates from the Ramp Rate Limits would result in constrained off compensation, resulting in costs.

Mr Peake sought clarification on whether it had to be linear ramping for a full 30-minutes, noting that there's re-dispatch at 10 and 20 minutes. It was Mr Fairclough's understanding that AEMO was looking at this and that it would have to determine exactly what the process is and when it would be used. Mr Peake noted that, with linear ramping, he would hate to see a situation where plants are at less than their minimum as it will lead to issues with the Economic Regulation Authority (**ERA**).

Mr Stephen questioned whether using linear ramping to solve the instructed output fluctuation problem might cause more uninstructed fluctuation issues. Ms Robins agreed, noting that if AEMO was going to moderate a generator's ramp rate and there is a loss of revenue associated with generating less, this would provide an incentive for participants to increase their ramp rates to the maximum so that they will not lose as much if they are moderated, making the aggregate ramp issue worse.

There was some discussion about whether participants are required to ramp at their maximum ramp rates. Mr Fairclough clarified that participants are required to be able to ramp at the ramp rate indicated in their Balancing Submissions, which is not necessarily always the Facility's maximum ramp rate.

5.5.1.5 The Need for an Automated Linear Ramping Process

Mr Fairclough considered that AEMO could implement linear ramping manually for a 90-minute BGC. Mr Sharafi explained that, with manual intervention, the controller sees that it cannot respond to a fast movement of generators so he or she limits the ramp rate of some of the units or the controller constrains the generator, which is done under not normal conditions.

Mr Fairclough noted that, in contrast, if there is a move to 60-minute BGC, AEMO would need to be able to implement automated linear ramping, requiring a more conservative formula, from that date. Mr Sharafi considered that AEMO would need to implement automated linear ramping because it is beyond the capacity of a human being to deal with that issue in that short period of time.

Mr Stephen offered that linear ramping is employed in the NEM, but that it is a five-minute interval, not a half hour interval, and ramping occurs at the ramp rates in the bidding, which do not get moderated. Ms Laidlaw considered that in three years' time, there will not necessarily need to be linear ramping because LFAS can pick up small imbalances with a five-minute dispatch cycle, which means that the cost to make everyone switch to linear ramping would be required for a short-term solution. Ms Papps considered that the cost to implement linear ramping for a 30-minute interval might be quite different, and that the solution is quite different, to a five-minute interval.

Ms Papps expressed concern that linear ramping may cause instability if the ramp rates could be anything up to the Ramp Rate Limit because governors can be tuned to specific ramp rates but there are limits to the variability in the ramp rates that can be used. Mr Sharafi considered that AEMO may not have visibility of this, which may create issues for generators.

Ms Laidlaw questioned whether linear ramping would be built into the RTDE as part of the automated solution. Mr Fairclough considered that there was no need to change the RTDE, as AEMO could simply change the ramp rate that it feeds into the RTDE. Mr Sharafi considered that the controller can manually override what goes into the RTDE.

Ms Laidlaw questioned how AEMO would work out what the units are going to be dispatched to, and therefore, who's going where, and at what speed, if AEMO does not look at it through the RTDE. Mr Fairclough considered that this would have to be considered in how AEMO implements linear ramping, as AEMO had not worked out exactly how it was going to work yet.

The Chair noted that questions of cost and practicality cannot be answered if we do not know how the linear ramping model is going to work. Mr Fairclough considered that AEMO would have to come up with a formula for how it would implement linear ramping and that this formula would apply whether AEMO did it manually or used an automated process. Mr Fairclough noted that the requirement to ramp linearly would be lower with a 90-minute BGC, leading to a difference in constrained off payments between the two scenarios.

There was discussion on whether an understanding of how linear ramping would work and its costs to AEMO and Market Participants would be required prior to publishing a Draft Rule Change Report and attendees agreed that that would be quite a large process.

5.5.1.6 Timeframe for Implementation of Linear Ramping

Ms Robins noted that AEMO had suggested that it will implement linear ramping irrespective of this Rule Change Proposal. Mr Fairclough indicated that AEMO would like to implement linear ramping now because it has had to use back-up LFAS three times in a week. However, Mr Fairclough considered that linear ramping would always be a last option and that, while AEMO is thinking about linear ramping for its current operations, AEMO is not going to introduce linear ramping tomorrow.

The Chair noted that there are costs and timing implications associated with implementing an automated linear ramping process. Ms Robins questioned whether, if linear ramping is something planned for the longer term, the Rule Change Proposal should be held off while AEMO implements linear ramping or it should proceed with some other option. Ms Robins noted that 400 MW of wind and 200 MW of residential solar will be added to the system by mid-next year, so Market Participants may want to shorten the BGC now, rather than waiting to implement an aggregate ramping solution.

Ms Papps noted that participants may need time to implement control system and governor changes to implement linear ramping, which requires outage planning, outages, testing, commissioning, and finding a supplier. Ms Papps considered that there is not enough information and participants do not have an outage plan or an outage scheduled, which makes it difficult to provide a timeframe.

Ms Robins considered that if work cannot start on implementing linear ramping until the end of next year, then the time frame is too close to when the market reforms will be implemented. The decision could be made to not implement linear ramping but to hold off for the reforms. Mr Sharafi noted that AEMO had avoided making wholesale changes to the RTDE because it knew that the reforms would address most of the issues, with a different dispatch period and different structure to the Ancillary Services.

Mr Sharafi considered that implementing linear ramping requires system changes, and the efficiency of the solution and what can be gained from it needs consideration. Mr Sharafi urged attendees to consider the Rule Change Proposal in the context of the reform program and its time frames and noted that System Management does not have any resources to focus on other things.

5.5.1.7 Synergy's Gate Closures

Ms Robins noted that for Synergy's LFAS Gate Closure, the forecast is 10.5 hours ahead of the first Trading Interval and 16 hours ahead of the last Trading Interval in the relevant LFAS block. There was some confusion around when Synergy's LFAS Gate Closure occurs under the Market Rules, with most participants assuming Synergy uses the same LFAS Gate Closure as IPPs (see section 6.2.2.2 for discussion of how the LFAS Gate Closure is specified under the Market Rules).

Ms Robins considered that, if the BGC is reduced for IPPs, then it would seem reasonable to also reduce Synergy's gate closure for the Balancing Market but cautioned that Synergy is the dominant player in the market and there is a need to avoid infeasible dispatch. Mr Huppatz noted that, in its submission, Synergy indicated that it should be treated on a level playing field with the same BGC as IPPs.

In contrast, Mr Peake and Ms Papps considered that Synergy's gate closure should be as close as possible to the BGC for IPPs, as this would be most efficient for the market, but should not be the same as for IPPs. Ms Papps noted there are still some things about the Balancing Portfolio that are different than for IPPs, which requires a different gate closure for Synergy.

Mr Sharafi considered that AEMO does not mind if Synergy's gate closure for the Balancing Market is the same as everyone else's, so long as LFAS Gate Closure is before that. The attendees agreed that there was no need to disrupt the order of gate closures, with Synergy's gate closure following the LFAS Gate Closure.

Ms Robins noted that consideration needed to be given to what IPPs need to do in the time between Synergy's gate closure and when they bid, and how long they need to do it. Ms Papps considered that IPPs need to wait for the information to come out of AEMO and then respond to that information. Mr Stephen noted that the information on the BMO is provided at the start of every half-hour, at one-minute past the half hour Synergy must make its submission, AEMO's system processes Synergy's submission, and then IPPs can see the result and decide if they must change their submission and make their submission.

The Chair questioned whether it was a long period between when Synergy makes its submission and when the BMO is in IPP hands and considered that if it was an automated process it would take less than a minute. Ms Papps considered that if the BMO comes out at 8.01 AM then IPPs would not want to have to make a submission before 8:30 AM, as 30 minutes is too short.

Mr Maticka considered that the market was designed to allow IPPs to respond to the dominance of Synergy and that, from a technical point of view, it makes no difference to the power system. However, Mr Maticka posed the question of whether it is the correct lever for addressing market power. Ms Laidlaw responded that, in contrast to Synergy, one of the IPP's biggest risks is infeasible dispatch, and that this risk increases if they do not have some forewarning of what the Balancing Portfolio is doing. However, Mr Huppatz considered that Synergy also faces infeasible dispatch because of the forecasting inaccuracy, and the long gate closure.

Ms Robins questioned whether anyone had concerns with Synergy having a rolling gate closure instead of block bidding, as this would reduce the time frame of operation between the last forecast and the bid for the start of the Trading Interval. Mr Huppatz advocated for a rolling gate closure, noting that the shorter the gate closure, the better for market efficiency, as Synergy can reflect what is required.

Mr Huppatz considered that the market has changed and that there is inefficiency and additional risk to the market by Synergy not going to a rolling gate closure. Mr Huppatz noted, for example, that increasingly, Synergy needs to be able to get its plant in or out of the market, however, if the decision is left too late, Synergy may be able to de-commit the plant but it cannot bid it out, so the volume stays in the market. Mr Huppatz noted, for example, that if AEMO wants to request that Cockburn comes on because of a security issue, it cannot provide that volume because it ramps slowly and needs to start early in the day to be on that night.

Similarly, Mr Maticka noted that if Synergy is sitting at a mid-low point, it would end up having to decommit some coal and then it might have to bring it back on very quickly, within half an hour or an hour. Mr Maticka considered that this could present some horrendous problems for the management of the fleet and that Synergy cannot respond if it has such forward blocks.

Mr Huppatz questioned the logic of the requirement that by 10:00 AM, Synergy cannot adjust what it is going to do or provide a signal to the market for what Synergy is doing over the evening peak and considered that it is unworkable. Mr Huppatz added that Synergy can manage base load plant with a fixed gate closure but as soon as it starts becoming mid-merit, trying to manage with a block that is 10 hours in advance is not ideal.

Ms Wendy Ng (ERM) noted that when the Market Rules were developed, the block bidding and time frames were developed just to manage market power issues. Ms Ng questioned whether everyone was comfortable that the market power issues had disappeared, before going down the path of introducing a rolling gate closure for Synergy. Ms Ng considered that everyone needs to be comfortable with the change, given that there is a new world that the market is going to that will have Facility bidding and potentially 30-minute gate closure, with everyone on the same time frames. Mr Maticka considered Ms Ng's point was correct, that block bidding should not just be removed without checking whether some of the logic around it is still valid.

Ms Laidlaw noted that there is a half hour delay for the second interval in a block and questioned how that delay mitigates market power. Mr Maticka recalled that the idea of the design was to provide a mechanism to encourage Synergy to pull Facilities out of the Balancing Portfolio. Mr Peake considered that there was also a reluctance to make large changes to the original market design.

5.5.1.8 What Happens if the Gate Closure Remains the Same?

Ms Laidlaw questioned what AEMO would do if a shorter BGC is not implemented, whether it would continue to use the combination of pre-advanced dispatch and LFAS, and whether

AEMO would have the same concerns about using LFAS and its effect on system security. Mr Sharafi confirmed that this was the case and that AEMO would still have these concerns.

Mr Fairclough considered that if there is a greater frequency and impost of unscheduled movements, AEMO are likely to get into the situation of constraining IPPs more often. AEMO do not want to introduce linear ramping now because it knows that it costs everyone but considers that this is the way things are heading. Mr Fairclough considered that the change to BGC had not instigated AEMO's view on the use of LFAS.

Ms Laidlaw sought clarification on whether AEMO is removing LFAS as an option to deal with the aggregate ramp issue. Mr Fairclough confirmed that this was the case. Ms Laidlaw questioned whether AEMO therefore needed to set up the first part of the automated system, to check every Trading Interval to see whether it will use LFAS, and therefore need to use one of the remaining options to address the aggregate ramp issue. Mr Fairclough considered that AEMO already have the tools to do this, to a degree, so it doesn't need to build something to get the information.

Ms Laidlaw sought clarification on whether AEMO knows when it needs to linear ramp and questioned whether it was just that more often than not, AEMO are moving the Balancing Portfolio around to solve the problem. Mr Fairclough considered that AEMO uses the Balancing Portfolio on 99% of occasions.

Ms Laidlaw questioned whether AEMO were only rarely using LFAS, as it was her understanding that it was the tool most commonly used by AEMO. Mr Fairclough considered that if AEMO did not do anything else, it would default to LFAS.

Ms Laidlaw questioned whether AEMO were proposing that, in the frequent set of situations when the imbalance was only small, it was going to use linear ramping rather than LFAS. Mr Fairclough considered that AEMO was not thinking about the times when there was a little impost, which would be business as usual, but more the times when there is a 10 MW/minute or higher impost.

Ms Laidlaw questioned whether AEMO would have a threshold of LFAS usage that it would determine, and beyond that threshold would then go to linear ramping? Mr Fairclough considered that there would not be an LFAS threshold, but that the automation would be based on AEMO's assumptions about what the Balancing Portfolio could do.

5.5.1.9 Feedback from Market Participants on Questions Raised During the Workshop

Participants provided feedback on several questions stemming from the discussions at the workshop, which is presented in full in Appendix B. The following sections summarise key issues raised in response to these questions.

Question 1 What would Market Participants like to advise the Rule Change Panel to do regarding System Management's proposal for linear ramping, considering the timeframe for implementation, and the options to move to 60 or 90-minute Balancing Gate Closure?

AEMO requested that the Rule Change Panel consider the costs of linear dispatch in the determination of the appropriate gate-closure. ERM considered that it will need certainty on when System Management decides to operationalise and use linear ramping to give it a timeframe to determine if it needs to make changes to the way that its logic operates and to implement those changes.

Kleenheat considered that aggregate ramping is increasingly inadequate in the context of a growing penetration of intermittent Non-Scheduled Generation and noted that more LFAS capacity must be on standby in real-time to compensate for deviations from the aggregate ramping schedule and the varying output of renewable energy sources. Kleenheat considered that this leads to excessive and unnecessary costs for the market and noted that it was in favour of linear ramping as a solution for ensuring energy demand is met during each Trading Interval at minimal cost for the market.

Kleenheat requested that the Rule Change Panel carefully assess the possible additional costs that will be incurred by Market Participants (including Retailers) in the context of rising market operation costs to accommodate the WEM reform program over the coming years. Kleenheat understood that a 90-minute BGC is achievable at minor cost but that this is not the case for a 60-minute BGC, and recommended that the Rule Change Panel undertake a cost-benefit analysis of the 60 and 90-minute BGC options to support the decision-making process.

Synergy considered that either a 60-minute or a 90-minute gate closure would represent an improvement to the current arrangements but preferred a 60-minute gate closure and for the Balancing Portfolio to have same gate closure as IPPs. Synergy considered that the gate closure for the Balancing Portfolio should be as short as practicable to provide the most accurate information to the market; and ensure consistency between Synergy's offer pricing and the units that are dispatchable in real time.

Synergy considered that linear ramping should be adopted irrespective of which gate closure is selected, and that it is neither appropriate nor efficient to accommodate IPP movements at their maximum ramp rate through intra-interval adjustments to the Balancing Portfolio that are manifestly inconsistent with the portfolio's end-of-interval targets. Synergy reiterated that, with the changing SWIS load profile, and as the instances of the portfolio being dispatched at minimum generation levels increases, it is unlikely that portfolio movements will be able to accommodate IPPs moving at their maximum-ramp-rate without impacting the provision of essential system services.

Question 2 What are the implications of linear ramping for your units?

Alinta, Bluewaters, and ERM highlighted the need for changes to their units to allow for linear ramping. Bluewaters considered that steam turbines will need different control valves to throttle steam flow to limit/control ramps and will also require more maintenance and inspections, with reduced time between inspection intervals. Alinta reiterated that implementing linear ramping for a 30-minute Trading Interval for its Scheduled Generators would require both control system and governor changes, and scheduling of planned outages. Alinta advised the Rule Change Panel to consider the cost of these changes, taking into account that the move to a five-minute dispatch cycle, as part of the market reforms, may be implemented differently to a 30-minute dispatch cycle.

Bluewaters and ERM noted the commercial impacts of linear ramping (i.e. if ramp rates are constrained Market Participants can either lose out on MWh or generate at higher prices than the market price for longer periods). Bluewaters considered that restricting the ramp rates of quicker moving plant may also introduce a higher likelihood of non-compliance for over-generation and outages for under-generation, as tolerance levels will be reduced given the lower ramp rates.

ERM requested that if and when there is a move to linear ramping, it is ensured that generators have access to either constrained off or on payments so that financially, they aren't penalised for having to burn significantly more fuel than they would otherwise expect to burn.

Question 3 What is it that other Market Participants need to do following Synergy's gate closure and before Balancing Gate Closure, and how long does this take?

Alinta and Bluewaters both considered that Market Participants would have to review prices and internal positions, and potentially submit variation Balancing Submissions to reflect all available information, provide for optimal dispatch based on costs, and avoid infeasible dispatch. While Alinta considered that this process takes at least 60-minutes, Bluewaters considered that it takes around 1.5 hours to ensure that all intervals in the short-term horizon are correct.

Question 4 Would a rolling gate closure for Synergy affect other Market Participants and, if so, how?

Alinta considered that a rolling gate closure for Synergy will not affect other Market Participants, if the BGC is at least 60-minutes after Synergy's gate closure. However, ERM and Bluewaters considered that Market Participants may find themselves reviewing and changing bids and offers more often, which Bluewaters considered would introduce additional costs to be recovered from the Balancing Market.

ERM noted that it would only advocate for a rolling gate closure for Synergy if there is a gate closure time difference between Synergy and Market Participants, as Synergy should not have the same gate closure time as Market Participants while it is still bidding on a portfolio basis.

Question 5 Should we reduce the timeframe between LFAS Gate Closure and Synergy's gate closure and, if so, by how much?

ERM considered that if Synergy has a reduced gate closure for LFAS, then Market Participants should also have a reduced gate closure for LFAS. However, both ERM and Alinta noted that they did not advocate reducing the timeframe between LFAS Gate Closure and Synergy's gate closure.

Alinta considered that 60 minutes will allow Synergy to assess its LFAS Enablement for the next block, assess its portfolio position and submit corresponding Balancing Submissions. Similarly, Synergy advised that a minimum 60-minute lag between LFAS Gate Closure and BGC is required to allow participants sufficient time to incorporate LFAS clearing volumes in balancing offers.

Kleenheat favoured reducing the timeframe between LFAS Gate Closure and other Market Participants' gate closure (including Synergy's) as much as possible. Kleenheat considered that this would improve the economic efficiency of the WEM, minimise the total cost of supply to the market, provide more accurate information to base Price-Quantity Pairs on in LFAS and Balancing Portfolio submissions, and reduce the uncertainty of those submissions, leading to lower risks and better price signals.

Question 6 What is it that Synergy needs to do following the LFAS Gate Closure and why?

Synergy noted that after LFAS Gate Closure, it may need to update its balancing offers to reflect LFAS clearing volumes, which generally requires a re-run of Synergy's dispatch and pricing models.

Question 7 What is it that other Market Participants need to do following the LFAS Gate Closure and why?

Alinta and Bluewaters provided similar responses, noting that following LFAS Gate Closure Market Participants will need to assess their LFAS Enablement, make Balancing Submissions reflective of their LFAS Enablement, and prepare units to provide LFAS if required. Bluewaters also considered that IPP's may need to review the dispatch of associated generation Facilities to ensure sufficient energy is dispatched to meet their customer requirements if capacity has now been reserved for LFAS provision.

Question 8 Would a rolling LFAS Gate Closure affect Market Participants and, if so, how?

Alinta considered that a rolling LFAS Gate Closure may have high implementation costs or lead to inefficient or non-compliant outcomes because changes in LFAS Enablement require corresponding Balancing Submissions for Facilities to be dispatched optimally. Alinta explained that having a rolling LFAS Gate Closure means personnel will need to check changes in LFAS Enablement every 30 minutes, and if they fail to check and reflect changes in LFAS Enablement, it will either lead to non-compliance or the Facility will be underutilised. Alinta considered that these issues can be mitigated through a systemised solution, however it would be costly to implement, and the issues should be resolved with the market reform, as energy and essential system services will be co-optimised.

Bluewaters highlighted the additional costs associated with increased trading efforts, and Synergy considered that because of the frequency with which participants would have to update their Balancing Submissions, it is desirable to retain the current LFAS 6-hour (or similar) block structure.

5.5.2 18 October 2019 MAC Workshop

5.5.2.1 Constraining IPPs to Address the Aggregate Ramp Issue

Mr Fairclough confirmed that AEMO had reconsidered the options it has available to respond to the aggregate ramp of IPPs in a normal operating state and had discounted the option of constraining IPP Facilities. Mr Fairclough explained that constraining IPPs is effectively linear ramping, because instead of issuing a Dispatch Instruction at the ramp rate that the participant put in their Balancing Submission, AEMO will come up with a different ramp rate, whilst keeping the quantity in the Dispatch Instruction the same.

5.5.2.2 Incidence of the Aggregate Ramp Issue in 2018/19

Ms Robins noted that since the first workshop, AEMO developed a formula for predicting when linear dispatch will be required, based on the assumption that the only option available to System Management to offset the aggregate ramp of IPPs is to displace the Balancing Portfolio within the Trading Interval.

Mr Fairclough explained that AEMO had applied this formula to the market outcomes for 2018/19 to determine that linear ramping would have been required in about 10% of Trading Intervals (about five times per day) at a 60-minute BGC, and in about 7% of Trading Intervals (about three times per day) at a 90-minute BGC over that period. Mr Fairclough considered that the findings for the 90-minute BGC option were the same as for a two-hour BGC, and that the added half an hour didn't really make that much of a difference as far as determining what AEMO can do in advance.

5.5.2.3 The use of the LFAS Requirement to Address Instructed Fluctuations in Scheduled Generation

Ms Laidlaw noted that the incidence of the aggregate ramp issue seems very high at 7% and questioned why the risk of using LFAS materialises and must be acted on for the extra 3% at the 60-minute BGC and not at the 90-minute BGC. Mr Fairclough considered that:

- Saying there is a 3% difference doesn't capture all aspects of the issue, as AEMO:
  - only has what the Balancing Portfolio can move in the 60-minute BGC scenario; and
  - can dispatch more in advance in the 90-minute scenario.
- The 3% difference between the two scenarios in terms of the Trading Intervals when the aggregate ramp issue occurs requires that 20% of the energy would be constrained, which is significant.
- At a 60-minute BGC, the issue occurs in 10% of the intervals,[12] which is too much to rely on LFAS Facilities.
- The impost is too much for AEMO to determine which Trading Intervals would be manageable.
- A blanket cut-off would be employed such that LFAS could not be used any time the threshold is exceeded.

Ms Laidlaw and Mr Huppatz questioned whether AEMO's interpretation of the Market Rules, that LFAS can only be used for uninstructed fluctuations, meant that AEMO would have to apply linear ramping in the 7% of cases where the aggregate ramping issue occurs now. Mr Fairclough explained that with the definition of LFAS, the LFAS Requirement does not change and AEMO is bearing the risk of eating into the available LFAS. Mr Sharafi noted that at the beginning of the Trading Interval, AEMO eats into the LFAS but, as you move forward into the Trading Interval, the risk becomes smaller and smaller.

Mr Sharafi considered that AEMO should only use LFAS when it does not have any other choice. However, Mr Sharafi also noted that currently LFAS is used to enable the aggregate ramping of generators and that the situation would remain the same with a move to a 90-minute BGC.

Mr Arias questioned whether AEMO had considered the cost of using and enabling more LFAS per Trading Interval and not moving to automated linear ramping. Mr Sharafi confirmed that this was a consideration. However, Mr Fairclough explained that the issue is that the definition of LFAS does not include instructed changes.

Mr Arias considered that AEMO is already eating into the LFAS to address instructed fluctuations, regardless of how LFAS is specified. Mr Fairclough explained that AEMO had set its requirement ignoring instructed changes, and that AEMO was eating into that requirement at certain times and the question was about how often the market can live with that risk.

Ms Laidlaw questioned whether the Market Rules were necessarily the sticking point, considering that AEMO had technically not previously been setting the requirement according to the Market Rules, as it would not have provided enough LFAS for the system. Mr Fairclough considered that AEMO did not necessarily share this position.

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12 AEMO later corrected this value to 11% following the identification of errors in the calculation.

Ms Laidlaw cautioned that putting on additional LFAS may be a high cost option, particularly if the SWIS starts to run out of generation. Ms Robins questioned whether removing the use of LFAS to address the aggregate ramp issue is reasonable, given the need to maintain system security and reliability prior to the reforms. Mr Huppatz suggested that the LFAS Enablement may be one of the considerations in a cost benefit analysis (i.e. you either go for linear ramping to manage system security or you review how much LFAS is enabled or utilised).

5.5.2.4 Scope of the Rule Change Proposal

Ms Robins noted that, following the first workshop, RCP Support had received legal advice that the scope of the Rule Change Proposal is about 'accuracy of information' and that amendments to the Market Rules, such as the introduction of staggered or linear ramping, and changes to the LFAS Requirement, are outside the scope of this Rule Change Proposal. Ms Robins considered however, that this did not provide a barrier to moving to a 60- or 90-minute BGC, as AEMO had indicated that it could implement linear ramping without changes to the Market Rules.

5.5.2.5 Linear Ramping

Mr Huppatz offered that consideration needs to be given to linear ramping because of where the loads and dispatch are heading. Mr Huppatz considered that some form of linear ramping will be needed to ensure system security and that this probably informs the cost benefit analysis that RCP Support will undertake. Mr Quentin Jeay (Kleenheat) agreed and considered that it is better for the customer who pays for the cost of energy.

Ms Robins cautioned that any linear ramping introduced prior to the Energy Transformation Strategy (**ETS**) reforms[13] would have to be devised, designed and implemented to fit on top of the existing system, and that, at this point, we do not have a good understanding of how linear ramping might work in practice in the existing system. Mr Lei noted that the introduction of linear ramping slated for the ETS reforms was based on a 5-minute dispatch cycle rather than the current ten-minute cycle, and that this would solve a lot of the aggregate ramping issue. Mr Lei questioned whether this process is just about solving the issues until the ETS reforms kick in, and it was agreed that this was the case.

Ms Laidlaw noted that at the last workshop AEMO indicated that it was going to implement linear ramping and the question was whether it would have to be automated. Mr Fairclough confirmed this but suggested that the point was that AEMO may need to get to linear ramping at some stage, but AEMO has not foreseen a need to introduce it yet and will reassess this next year. Mr Lei reiterated Alinta's concerns about its machines, which are tuned to a certain ramp rate and will be very unstable if they are required to ramp at different ramp rates, noting that there will be a risk of them tripping more often.

5.5.2.6 How will the Automated Linear Ramping Process Work?

Ms Laidlaw questioned whether an automated linear ramping process would assume that the Balancing Portfolio was being dispatched at 15 MW/minute or whether this does not matter. Mr Fairclough considered that it does not matter, as the quantities remain the same and it's just the ramp to get there that matters.

Mr Fairclough explained that if there was an aggregate ramp issue that could not be offset by the Balancing Portfolio and linear ramping was necessary, then every Facility would be

[13] The ETS reforms are the successor to the EMR program.

dispatched linearly, which would be aggregated, and the Balancing Portfolio would ramp accordingly to offset the aggregate ramp. Mr Fairclough considered that the ramp that the Balancing Portfolio must deal with will always be set using a manual process and not using LFAS.

Ms Laidlaw questioned whether the Balancing Portfolio would be dispatched to a specific target, and if not, how AEMO would work out where to send the Balancing Portfolio if it was not using LFAS. Mr Fairclough considered that AEMO would not dispatch the Balancing Portfolio to a specific target but would move the Balancing Portfolio around during the Trading Interval to offset whatever remaining aggregate ramp existed. Mr Fairclough considered that it was not clear how AEMO would determine where to send the Balancing Portfolio but that controllers are trained to work this out.

5.5.2.7 Manual Linear Ramping

Ms Laidlaw and Mr Lei questioned whether, to stop using LFAS, AEMO's plan was to use linear ramping in the 7% of Trading Intervals where the aggregate ramp issue already occurs (i.e. at a two-hour gate closure). Mr Fairclough explained that if the market is not going to a 60-minute BGC, there are 7% of intervals where the Balancing Portfolio's ability to offset all other movements are exceeded, but because it has a bit more time and more options, things do not need to be automated and can be dealt with manually. Mr Fairclough considered that this may change at some point in the future but AEMO can deal with it right now and it is not intending to introduce manual linear ramping immediately.

Ms Laidlaw questioned whether AEMO had done any more work on how the manual linear ramping process would work and how at 90 or 60 minutes out, AEMO would determine what it needed to do and how it would change the ramp rates to linear ramp rates in the RTDE. Mr Fairclough noted that whilst it had not done any more work in this area, there was an existing manual process that allowed it to override the ramp rates.

Ms Laidlaw questioned how AEMO would work out the ramp rates for each generator and load them into the RTDE in time for each dispatch cycle. Mr Fairclough considered that AEMO would go through the same process that it used to work out when the linear ramping Trading Interval would occur, and at that point everyone's quantities would be divided by the time, and that would produce the linear ramping rates.

Ms Laidlaw questioned the practicality of this approach, given the timing requirements and that changes in demand and dispatch can occur within the ten-minute dispatch cycle. Ms Laidlaw asked at what stage AEMO would work out the dispatch requirements and input the ramp rates. Mr Sharafi considered that this was the controller's decision, based on their consideration of the conditions and determining what ramp rate each generator needs to get to its target.

Ms Laidlaw considered that the controller may need to override the ramp rate of only one or two generators, rather than everyone, and questioned whether it would be necessary to switch everyone over to linear ramping, which is quite involved. Mr Sharafi noted that AEMO had not done this yet, so it had not yet determined its process.

Mr Fairclough considered that the problem is that it's more difficult to do the calculation to pick a winner than just to say that, unfortunately, everyone loses, and if AEMO did pick winners, it would have to have a process for determining who would be the winner, which would be quite challenging.

Mr Fairclough noted that every now and again it had had to vary the ramp rates of Facilities, but not on a regular basis, and it was usually only for one or two Facilities. Mr Huppatz considered that AEMO routinely move the Balancing Portfolio outside of its clearing volumes to accommodate the ramping issue. Mr Fairclough considered that AEMO moves the Balancing Portfolio to ensure Power System Security.

Mr Fairclough explained that most of the time AEMO deals with the aggregate ramp issue by dispatching the Balancing Portfolio in advance, so that whoever is causing the aggregate ramp issue can do what it wants. Where that is not possible, AEMO absorbs the impost on LFAS machines. However, in some cases, there are Facilities with very high ramp rates that are ramping in different ways, but they are generally the only generators ramping when this occurs, so AEMO modifies the ramp rates of those Facilities. Mr Fairclough clarified that AEMO has not been in a situation yet where five other machines are also ramping.

5.5.2.8 Assessing the Benefits of the Proposal

Mr Fairclough considered that a dollar value for the costs associated with the Rule Change Proposal can be estimated but market simulation will be required to provide a dollar value estimate of the benefits from improved forecast accuracy. RCP Support agreed with Mr Fairclough, noting that this was the challenge that it was up against and questioned whether attendees had any suggestions for how the benefits of the Rule Change Proposal could be measured. No suggestions were put forward.

5.5.2.9 Enhancement of Information Used in Trading Decisions

Mr Sharafi noted that a major initiative to increase the accuracy of forecasting was to enable Non-Scheduled Generators to update their forecasts after BGC. Mr Sharafi questioned whether generators had made use of this initiative and noted that there are many things that can be done to increase the accuracy of the forecasts that are not currently being done.

Ms Laidlaw noted that generators have not made use of this initiative and considered that an updated forecast after BGC serves little purpose in terms of accuracy in bidding, as Market Participants cannot update their Balancing Submissions after BGC. However, Ms Laidlaw considered that the updated forecast would give Market Participants a better indication of whether they are about to be started up, which is useful from an operational standpoint.

Ms Laidlaw noted that a further option that may be useful operationally is to publish the current output of Non-Scheduled Generators (a persistence forecast) closer to real time to allow Market Participants to take that into account when they look at the BMO and see how much its likely to be affected. Ms Laidlaw considered that, at a certain stage, the persistence forecast is likely to be better than any forecast that a Market Participant is likely to get from Balancing Submissions.

Mr Paul Arias noted that AEMO is updating forecasts more frequently now and suggested another option to increase the accuracy of information available to Market Participants would be for AEMO to re-run and publish the Forecast BMO every 5 minutes. Mr Arias considered that five or six IPPs may change their position slightly in a half hour period and, if one of the IPPs is marginal, a Market Participant may get caught out due to sudden changes in price (e.g. the price could suddenly double or halve).

5.5.2.10 Amendments to Synergy's Gate Closure for the Balancing Market and the LFAS Gate Closure

Mr Lei noted that the main benefit of a reduced gate closure is better forecasts and questioned whether a lot of benefits could be realised if just Synergy's gate closure was reduced, without having all the cost associated with other changes to the BGC. Mr Lei considered that this would give Synergy time to consider more accurate information, as right now, it is locked out far ahead of time.

Ms Robins noted that, in the first workshop, there was general support for moving Synergy to a rolling gate closure and that an implication of moving Synergy to a rolling gate closure was that traders would need to monitor the Forecast BMO on a 24/7 basis to alleviate any risk of infeasible dispatch. However, when the possibility of moving the LFAS Gate Closure to a rolling gate closure was discussed, one of the Market Participants' concerns was that they may have to employ an additional trader because this would require 24/7 monitoring of the market. Additionally, Market Participants were concerned that there would be an increased risk that they would not realise that they had cleared in the LFAS Market, and therefore not reposition themselves accordingly in the Balancing Market, leading to penalties.

Ms Robins questioned whether, if there was a trader already monitoring the Balancing Market because of a Synergy rolling gate closure, there was an option to also move to a rolling gate closure for the LFAS Market. Mr Lei considered that LFAS and Balancing monitoring are different because if you are enabled for LFAS you must make a second Balancing Submission to reflect your enablement.

Mr Lei explained that, in contrast, Market Participants have a standing submission to react in the Balancing Market, so that a change to Synergy's Balancing Submission does not affect the validity of everyone else's Balancing Submissions and Market Participants are not obliged to submit another Balancing Submission. Mr Arias considered that changes to Balancing Submissions had to occur as soon as the participant knows that they are enabled following LFAS Gate Closure and, if participants have a standing submission, then that would need to be tweaked three times a day or more, based on the mix and how much is enabled.

Mr Huppatz considered that there are quite different drivers for LFAS and offered that participants have to see what is clearing in the market, which can change up to gate closure, and check that their Balancing Submissions have sufficient LFAS at the cap and floor pricing, to meet the obligation. Mr Huppatz noted that, if you bid at the floor, the risk is that you are capped at the floor, and it is not an economic run if you get put on.

Mr Arias agreed, noting that, with Balancing, if you are committed, you will guarantee a run level and price things so that if something is changed (e.g. someone else comes out) you can go either higher or lower in price. It is LFAS that leads to the obligation to then change bids in the Balancing Market.

Additionally, Mr Arias considered that a rolling gate closure for Synergy doesn't necessarily require a review every half an hour, whereas if you go to a rolling LFAS Gate Closure, and you are participating or planning on bidding into that market, you will have to review it every half an hour because of the potential for non-compliance issues. Accordingly, Mr Arias considered that block bidding for LFAS was still the preferred option. In response to a question on whether a two-hour LFAS Horizon (instead of 6 or 4-hour blocks) would introduce too much risk, Mr Arias considered that the risk would be too great not to have a trader on duty.

Ms Laidlaw questioned whether the LFAS Merit Order sometimes changes a participant's fundamental dispatch. Mr Arias considered that it can sometimes change the minimum commitment levels, as there are no guarantees on how much will be cleared in LFAS, if you clear at all. Mr Arias noted that not all machines can provide LFAS for their entire operational range.

Ms Laidlaw questioned how often the results of the LFAS Market surprise Market Participants. Mr Arias responded that there are certain periods that may surprise you, and others which may be the same for weeks on end, but you would never run the risk of not checking. Mr Lei agreed, noting that the risk would be too high.

5.6 MAC Consultation Following the MAC Workshops

5.6.1 11 February 2020 MAC Meeting

Ms Robins presented the estimated costs of three options to provide additional Balancing Market information to Market Participants to help improve the accuracy of their trading decisions, including:

1. Assessment of the implications of increasing the frequency of the BMO calculation to every ten-minutes for the whole Balancing Horizon, at a cost of $20,000, and taking approximately four months to complete.
2. Implementation of calculation of the Forecast BMO every ten minutes only for the Trading Interval for which gate closure is about to occur, at a cost of $90,000, taking approximately three months to complete.
3. Implementation of publication of a 5-minute balancing load forecast in a new report at a cost of $20,000 and taking approximately one month to complete.

A copy of Ms Robins' presentation is available in the meeting papers.

Ms Robins sought feedback from MAC members on whether the benefits of the additional information provided under each of the three options would outweigh their estimated implementation costs.

Mr Daniel Kurz (Market Generators) noted that more information led to better decision-making and Mr Oscar Carlberg offered that Alinta would consider the net benefits of the options given how much time remained before the new market arrangements were to begin.

Ms Ng noted AEMO's concerns about the volume of data that would be created if the Forecast BMO was published every five minutes and questioned why this would not also be a problem for the proposed Security Constrained Economic Dispatch (**SCED**) systems. Mr Maticka explained that the current systems were designed to support a 30-minute cycle and would need to be upgraded to support a more frequent cycle. In contrast, the proposed SCED process will use new systems built on a different technology platform and will be designed and tuned for a five-minute cycle.

Mr Sharafi observed that none of the options presented was required to facilitate a shorter BGC.

Ms Robins requested that Market Participants provide feedback on the three options to RCP Support by the following week. The feedback from MAC members was mixed:

- two Market Generators considered that the proposal to recalculate the Forecast BMO every 10 minutes for every interval in the balancing horizon would not provide benefits proportional to the additional cost, whilst another considered that this option could provide up to date information to inform commitment levels for LFAS;
- one Market Generator considered that an updated Forecast BMO every 10-minutes just for the next Trading Interval would be useful, as it would allow generators to bid more accurately, and would be more cost-efficient compared to the first option, whilst others considered there was little quantifiable benefit to be gained from this option; and

- one respondent supported the proposals for an updated Forecast BMO every 10-minutes just for the next Trading Interval, and publication of the 5-minute balancing load forecast in a new report, due to the indirect benefits of an efficient market.

5.7 Out of Session Consultation with AEMO

On 12 November 2019, AEMO provided RCP Support with an estimate of the constraint payments that it expected would occur with the introduction of automated linear ramping. AEMO used its analysis of the 2018/19 year determining the frequency of the requirement for linear ramping to determine that yearly constraint payments between $1.3 million and $2.2 million would be required, depending on the quantity of LFAS used.

On 24 December 2019, AEMO provided RCP Support with an estimate for implementing automated linear ramping of $200,000.

On 30 January 2020, RCP Support sought clarification on AEMO's understanding of several matters raised in relation to the Rule Change Proposal. Feedback was provided to RCP Support on 21 February 2020. Key aspects of this consultation are outlined below.

5.7.1 Existing Options for Addressing the Aggregate Ramp Issue

5.7.1.1 Constraining IPP Ramp Rates

At the 6 September 2019 workshop, AEMO outlined three options for addressing the aggregate ramp issue, two of which involved offsetting the aggregate ramp using the Balancing Portfolio, and a third option, which was to constrain non-Synergy Facilities (see section 5.5.1.3).

In relation to the constraint of non-Synergy Facilities AEMO explained that, in some cases in the past, there were Facilities with very high ramp rates that were ramping in different ways, but they were generally the only generators ramping when this occurred, so AEMO modified the ramp rates of those Facilities. AEMO clarified that it had not been in a situation yet where five other machines were also ramping.

However, at the MAC workshop on 18 October 2019, AEMO considered that constraining non-Synergy Facilities was no longer an option to address the aggregate ramp issue because:

- Issuing Dispatch Instructions to constrain non-Synergy Facilities that are causing the aggregate ramp issue is 'effectively linear dispatch.' In support of this, AEMO explained that instead of issuing a Dispatch Instruction at the ramp rate that the participant put in its Balancing Submission, it would come up with a different ramp rate, whilst keeping the quantity in the Dispatch Instruction the same.
- If AEMO gets into a High Risk Operating State because of an action that AEMO has taken in the first instance, it becomes conflicted because it then needs to constrain non-Synergy Facilities because of AEMO's actions.
- Constraining non-Synergy Facilities would conflict with the Market Rules because it would require Out of Merit Dispatch, which can only be used to avoid a High Risk Operating State.

Given the difference in explanations, the Rule Change Panel sought clarification on whether AEMO is able to constrain IPP Facilities to respond to the aggregate ramp issue.

AEMO considered that, while it can constrain non-Synergy Facilities, this is not the preferred option because this will result in discretionary outcomes (i.e. picking winners and losers).

It was also AEMO's understanding that all Facilities that ramp in an interval contribute to the aggregate ramping issue and that constraining a specific Facility will constitute Out of Merit Dispatch under clauses 7.6.1C(b) or 7.6.1C(c). AEMO considered that, when read in conjunction with clause 7.6.1D, clause 7.6.1C appears to indicate that options should first be pursued that do not trigger the need to issue Dispatch Instructions Out of Merit.

AEMO further considered that, in its view, the intent of the priority order of Dispatch set out in clauses 7.6.1C and 7.6.1D is such that AEMO should maintain in-merit dispatch as a priority under clause 7.6.1C(a) over reverting to Out of Merit Dispatch under clauses 7.6.1C(b) or 7.6.1C(c).

According to AEMO, the implementation of a linear ramping solution at a 60-minute BGC would enable this because dispatch under this method remains in-merit, whereas selectively constraining IPP Facilities would not.

5.7.1.2 Can Instructed Fluctuations be Included in the LFAS Requirement

RCP Support sought clarification from AEMO on its understanding of the LFAS Requirement and whether it can be employed to address fluctuations in the balance between supply and demand due to the dispatch of Scheduled Generators.

AEMO noted that, as indicated in its 2018 and 2019 Ancillary Services Reports, AEMO derives its LFAS Requirement through its analysis of differences in forecast error at different times of the day, where these differences are between forecast and final Non-Scheduled Generation output as well as the difference between demand forecasts and actual demand.

AEMO explained that the LFAS Requirement is set excluding fluctuations from the instructed dispatch of Scheduled Generators and considered that this was consistent with the intent of the standard specified in clause 3.10.1 of the Market Rules.

AEMO noted that in its view, under clause 3.11.1, AEMO must determine its requirements in accordance with the Ancillary Service Standards, including those in clause 3.10.1, which means that, by definition, the LFAS Requirement cannot be set with the intent to cover the issue of the aggregate ramping of non-Synergy Facilities. This, according to AEMO, is the main challenge for implementing a shorter gate closure.

5.7.1.3 Can we just Increase the LFAS Requirement to Reduce the BGC?

RCP Support requested clarification on whether a change to increase the LFAS Requirement is needed to reduce the BGC and by how much.

AEMO explained that currently, the aggregate ramp issue is managed through the manual dispatch of the Balancing Portfolio, and in real-time, the system responds so that any supply-demand imbalances remaining after the dispatch of the Balancing Portfolio are managed by LFAS. AEMO considered that the current use of LFAS for scheduled movements is a result of how the power system operates.

AEMO noted that under the existing gate closure or with a move to a 90-minute BGC, its intention is to continue to operate in this manner. However, at a 60-minute BGC, AEMO considered that the frequency of the aggregate ramp issue (i.e. greater than 10% of intervals after taking into account the dispatch of the Balancing Portfolio to offset non-Synergy scheduled ramping) would be a problem requiring the implementation of linear ramping.

AEMO reiterated that addressing aggregate ramping at a 60-minute BGC through LFAS is not an option. AEMO considered, that relying on LFAS is likely to not only lead to increased LFAS costs but will also lead to Power System Security risks because, as per the standard set in clause 3.10.1 of the Market Rules, LFAS is not intended to be used for scheduled plant movements.

Additionally, AEMO noted that the Market Rules do not provide for a change in LFAS Requirements in these circumstances because the derivation of the LFAS Requirement under the clause 3.10.1 standard in the Market Rules expressly excludes instructed movements of Scheduled Generators. As such, an increase in the LFAS Requirement is not permitted and an alternative solution is required in the form of linear ramping.

5.7.2 AEMO's Linear Ramping Solution

5.7.2.1 Is Linear Ramping Necessary?

RCP Support requested clarification on the requirement for linear ramping if the BGC is to be shortened. AEMO explained that it is continually monitoring and assessing whether a transition to a linear ramping solution is required under the current gate-closure arrangements (i.e. irrespective of a change to the BGC). AEMO considers that if system conditions accelerate, it may be required to introduce linear ramping at the existing 2-hour BGC.

AEMO reiterated that currently, the aggregate ramp issue is managed through manual dispatch of the Balancing Portfolio, with LFAS used to manage the remaining imbalances, and infrequently, AEMO has constrained individual IPPs due to excessive ramping. AEMO considered that, with a move to a:

- 90-minute BGC, AEMO will continue to operate in this manner and it will monitor if and when current practices need to change to transition to linear ramping, as it has observed that bidding behaviour and system conditions appear to be changing.
- 60-minute BGC, AEMO will implement an automated linear ramping solution from the implementation date because:
    - of the frequency of the aggregate ramp issue;
    - it will remove the risk of discretionary outcomes (i.e. picking winners and losers) that would result from a manual solution; and
    - it will minimise the impact on LFAS.

AEMO expressed the view that the concept of linear ramping is consistent with the current Market Rules and the WEM Objectives and also with the future direction of the market under the reforms.

5.7.2.2 How Will Linear Ramping Work?

RCP Support sought detailed clarification of how the linear ramping process will work at a practical level, including, in particular:

- how and at what point the RTDE would accommodate the outputs of the operation of the automated linear ramping tool in the RTDEs current mode of operation, and
- whether it is possible to implement an automated linear ramping tool that works in conjunction with the RTDE, without making wholesale changes to the way that the RTDE operates.

AEMO noted that linear ramping is provided for under the current Market Rules. AEMO anticipated that the RTDE changes would not constitute wholesale changes to the system or the RTDE to accommodate a new external automated linear ramping tool.

AEMO considered that the detailed methodology, which summarises AEMO's approach to determining when linear ramping is required (provided in the context of AEMO's analysis determining the frequency of the aggregate ramp issue) contained several steps that indicate how the requirement for linear ramping would be calculated.

AEMO considered that this analysis and the slides provided at the 6 September 2019 MAC workshop (see section 5.5.1) provided a high level understanding of how linear ramping would work, including how Synergy would first be dispatched to offset non-Synergy scheduled movements and how the dispatch of non-Synergy Facilities would be calculated.

5.7.2.3 Is Linear Ramping Needed Across a Full 30-Minute Trading Interval?

RCP Support noted that the aggregate ramp issue occurs in the first few minutes of a Trading Interval and sought clarification from AEMO on whether there is a requirement for linear ramping across an entire 30-minute Trading Interval and why.

AEMO confirmed that the aggregate ramp of Scheduled Generators is of most concern during the first 10 minutes of the interval. However, AEMO noted that under its proposed design, all Market Participants will be directed to ramp linearly to a target at the end of the 30-minute Trading Interval at a reduced ramp rate. AEMO considered that implementing linear ramping over the entire interval is necessary to ensure consistent dispatch outcomes without the need to pick winners and losers, mitigate the risk of manual controller intervention, and mitigate the impact on LFAS usage.

5.7.2.4 Frequency of the Need for Linear Ramping Using AEMO's New Method for Determining When Linear Ramping is Required

RCP Support noted that when AEMO's new method of determining when linear ramping is required was applied to the 2018/19 period, it indicated that linear ramping would have been required in 7% of Trading Intervals at a 90-minute BGC, and that this was the same as the current 2-hour gate closure. However, RCP Support noted that automated linear ramping was not needed in 7% of Trading Intervals in 2018/19 and questioned the validity of AEMO's new method of determining when automated linear ramping of IPPs is required.

AEMO acknowledged that, based on historical bidding behaviour, the risks are lower at the 90-minute and 2-hour gate closure timeframes. AEMO noted that linear ramping is not currently employed under the existing 2-hour gate closure and that, as per its previous submissions, this also applies to a potential shift to a 90-minute BGC. However, AEMO considered that bidding behaviour and system conditions appear to be changing and AEMO may be required to transition to linear dispatch under the current gate-closure.

6. The Rule Change Panel's Draft Assessment

In preparing its Draft Rule Change Report, the Rule Change Panel must assess the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3 of the Market Rules.

Clause 2.4.2 of the Market Rules states that the Rule Change Panel "*must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives*".

Clause 2.4.3 of the Market Rules states that, when deciding whether to make Amending Rules, the Rule Change Panel must have regard to:

- any applicable statement of policy principles the Minister has issued to the Rule Change Panel under clause 2.5.2 of the Market Rules;
- the practicality and cost of implementing the proposal;
- the views expressed in submissions and by the MAC; and
- any technical studies that the Rule Change Panel considers necessary to assist in assessing the Rule Change Proposal.

In making its draft decision, the Rule Change Panel has had regard to each of the matters described in clauses 2.4.2 and 2.4.3 of the Market Rules as follows:

- the Rule Change Panel's assessment of the Rule Change Proposal against the Wholesale Market Objectives is available in section 6.4 of this report;
- the Rule Change Panel notes that there has not been any applicable statement of policy principles from the Minister in respect of the Rule Change Proposal;
- the Rule Change Panel's assessment of the practicality and cost of implementing the Rule Change Proposal is available in section 6.6 of this report;
- a summary of the views expressed in submissions and by the MAC is available in section 5 of this report. The Rule Change Panel's response to these views is available in Appendix A of this report; and
- the Rule Change Panel does not believe a technical study in respect of the Rule Change Proposal is required and therefore has not commissioned one.

The Rule Change Panel's assessment is presented in the following sections.

6.1 Assessment of the Proposed Changes

The assessment of the proposed changes and the rationale for the Rule Change Panel's draft decision are set out below. In summary, the Rule Change Panel considers that:

- A 30-minute BGC is infeasible, given the existing market systems and processes, and the timeframe for starting some gas units, which can be up to 15 minutes (see section 6.1.2). A 30-minute or shorter BGC is best addressed as part of the Government's ETS reforms, which are scheduled for progressive implementation from 1 October 2022.
- A 60-minute BGC is not desirable, given that AEMO has indicated that:
    - o from the date of implementation of a 60-minute BGC, it would implement a complex automated linear ramping process to address imbalances between the aggregate ramp rate of IPPs and the ramp rate of demand that cannot be offset by the Balancing Portfolio (see section 5.7.2). Implementation of this process will be costly

and time consuming and will lead to a considerable increase in constraint payments (see section 6.6.3).

- o Synergy will be increasingly required to offset the aggregate ramp rate of IPPs within the Trading Interval, which could involve moving the Balancing Portfolio at ramp rates greater than the Ramp Rate Limit in Synergy's Balancing Submission, despite Synergy:
  - receiving less remuneration for supplying Ancillary Services now that other Market Participants provide LFAS; and
  - being dispatched at lower generation levels due to the changing SWIS load profile from an increasing penetration of solar PV and will therefore likely be physically less able to provide a service to offset the aggregate ramp rate of IPPs in the future.[14]

- A 90-minute BGC is achievable given that AEMO has indicated that it will not require any material costs or changes to AMEO's current systems or Market Participant's systems and is not expected to significantly increase constraint compensation. Additionally, the Rule Change Panel has found that it will lead to an increase in Load for Scheduled Generation (**LSG**) forecast accuracy of 1.34 MW from the current BGC (see section 6.1.3.2).

Therefore, the Rule Change Panel's draft decision is to move to a 90-minute BGC. The Rule Change Panel's assessment informing this decision is outlined in the remainder of section 6.1. Additional changes to Synergy's gate closure for the Balancing Market and to the LFAS Gate Closure are discussed in section 6.2.

6.1.1 Scope of the Rule Change Proposal

At the 6 September 2019 MAC workshop, AEMO asked whether amendments to the LFAS Gate Closure are within the scope of the Rule Change Proposal, so the Rule Change Panel sought legal advice about the scope of the Rule Change Proposal.

On the basis of this advice, the Rule Change Panel considers that amendments to the LFAS Gate Closure are within the scope of the Rule Change Proposal, because:

- there is a direct link between the LFAS Gate Closure and the BGC, as the LFAS Gate Closure is defined by reference to the BGC, and any change to the BGC will necessitate a change to the LFAS Gate Closure; and
- the intent in the development of the original proposal to reduce the BGC (PRC_2014_01) was to also reduce Synergy's gate closure for the Balancing Market and the LFAS Gate Closure, which suggests that the issue that the Rule Change Proposal is seeking to address may be broader than just the forecast information in the Balancing Market, as indicated in the submissions made by Alinta and AEMO.

However, the implementation of linear or staggered ramping, which require material changes to other functions such as the RTDE and the settlement Market Rules for calculating TES and constrained on and constrained off compensation, are beyond the scope of the Rule Change Proposal, as they go beyond the general issue of forecast accuracy.

[14] However, it is not clear whether this will continue in the foreseeable future due to the downturn in the economy because of the COVID-19 pandemic (see section 6.1.7.3).

The Rule Change Panel notes that AEMO has indicated that:

- it may need to implement linear ramping at some point in the future irrespective of any changes to the BGC;
- it can implement a 90-minute BGC without immediately implementing linear ramping;
- it will need to implement automated linear ramping to implement a 60-minute or shorter BGC; and
- it believes that it can implement linear ramping with no changes to the Market Rules.

Based on these considerations, and given that the Rule Change Panel has decided to approve a 90-minute BGC, the Rule Change Panel takes no view on if, how or when AEMO should implement linear ramping; nor on whether changes to the Market Rules would be necessary for AEMO to implement linear ramping.

6.1.2 Options for Reducing the BGC

The Rule Change Panel notes that there was general support from IPPs for a move to a 30-minute BGC. However, Synergy did not agree with this proposal, as the option to also reduce Synergy's gate closure for the Balancing Market was not contemplated in the proposal and Synergy was concerned that IPPs would be advantaged by widening the gap between Synergy's gate closure for the Balancing Market and the BGC.

As set out in section 6.1.1, the option to reduce Synergy's gate closure for the Balancing Market is within the scope of this Rule Change Proposal. Therefore, the Rule Change Panel has assessed whether Synergy's gate closure for the Balancing Market should be amended as part of this Rule Change Proposal. See section 6.2.1 for the Rule Change Panel's assessment and draft decision on this matter.

The Rule Change Panel also notes that AEMO did not support the move to a 30-minute BGC because it considered that a reduction to 30 minutes is infeasible with the current hybrid design of the Balancing Market, and in the absence of more fundamental reform of the WEM. AEMO noted that it takes a few minutes to do an initial assessment of the BMO and then 15 to 20 minutes to perform a detailed assessment to plan material changes to the Balancing Portfolio dispatch (see section 5.2.1.3). The Rule Change Panel considers that the timeframe of AEMO's process, when combined with a 15-minute start up period for open cycle gas turbines, is too lengthy to accommodate a 30-minute BGC.

In relation to this, the Rule Change Panel notes that a greater reliance on more flexible plant in the market, such as fast starting gas fired power plants, may provide the plasticity needed to manage dispatch and address the aggregate ramp issue, and is a likely outcome of the increasing penetration of renewables in the long term. However, the Rule Change Panel considers that it is better to allow a smooth transition of the market to accommodate a greater penetration of renewables than to implement a BGC that will make dispatch unmanageable and might risk stranding existing assets, such as slow-ramping Facilities (e.g. coal fired power plants).

The Rule Change Panel acknowledges Alinta's observation that a 30-minute BGC should be manageable because even in the current circumstances. System Management can address late changes to offers close to real time and it can call a High Risk or Emergency Operating State to resolve any Power System Security and/or reliability issues. However, the Rule Change Panel considers that these scenarios should be exceptions rather than the norm.

Therefore, the Rule Change Panel agrees with AEMO that a move to a 30-minute BGC is infeasible under the current market design.

In contrast to the 30-minute option for reducing the BGC, AEMO advised that:

- a 60-minute BGC would require some complementary changes to dispatch and settlement arrangements, to reduce the scope of preparatory steps, and the time needed to execute them; and
- a 90-minute BGC is likely to be achievable without any added changes to the design of the Balancing Market, although this may result in some increases to constrained on or constrained off compensation.

The Rule Change Panel agrees with both Perth Energy and Alinta, who supported consideration of alternative reduced gate closure options if a 30-minute option is not possible. The following sections set out the Rule Change Panel's consideration of the 60-minute and 90-minute BGC options.

6.1.3 Forecasting Accuracy at Shorter BGCs

6.1.3.1 How does Access to More Accurate Information Result in Efficiencies in the WEM?

The Rule Change Panel notes that under clause 7A.2.4., a Market Participant's Balancing Submissions must have Balancing Price-Quantity Pairs within the price caps and specify, for each Trading Interval covered in the Balancing Submission, whether the Facility is to use liquid or non-liquid fuel, the Ramp Rate Limit or Portfolio Ramp Rate Limit, and the available and unavailable capacity.

The Rule Change Panel considers that, to alter a Balancing Submission to better reflect changing market conditions, Market Participants are less likely to alter:

- the type of fuel used by their Facility, as Market Participants will want to ensure that they run their plants using the most efficient fuel source for their Facilities;
- their Ramp Rate Limit, as most Market Participants elect to ramp at their maximum Ramp Rates to maximise production within a Trading Interval;[15] and
- the available capacity, as all available capacity must be submitted into the Balancing Market.

Additionally, the Rule Change Panel notes that the pricing behaviour of Market Participants is constrained by the Market Rules. For any Trading Interval, Market Participants must not offer prices in their Balancing Submissions in excess of their reasonable expectation of the SRMC of generating the relevant electricity by the Balancing Facility, when such behaviour relates to market power. The risk of being non-compliant should therefore deter Market Participants from offering their quantities at higher than SRMC in response to changing market conditions.

15 Not all Facilities ramp at their maximum ramp capability. The Market Rules do not require that Market Participants set a Scheduled Generator's Ramp Rate Limit at the Facility's maximum ramp capability. The Market Rules define the Ramp Rate Limit as a Market Participant's best estimate, in MW per minute, on a linear basis, of a Facility's physical ability to increase or decrease its output from the commencement of a Trading Interval. However, this can vary, depending on whether a Facility is generating at its minimum stable level or a different output level. Clause 2.1.4 of the Market Procedure: Balancing Facility Requirements requires that a Market Participant is capable of responding to an electronic Dispatch Instruction from AEMO for each of its Balancing Facilities to ramp upwards or downwards to a target MW level at a rate less than or equal to the Facilities Ramp Rate Limit. This leaves the setting of the Facility ramp rate to the discretion of the Market Participant.

However, the Rule Change Panel considers that Market Participants are able to alter their Price-Quantity Pairs to reposition themselves in the Balancing Merit Order, based on more up to date information. Under the current market design, Market Participants can opt to bid their quantities:

- at the price cap to remove the risk of being called upon to run at a clearing price that is lower than their operating costs, leading to a loss; or
- at the price floor, to ensure dispatch of these quantities.

The Rule Change Panel considers that for most thermal power plants with a minimum stable generation (minimum generation) greater than zero, the respective Market Participant will (depending on any bilateral contracts and the outcome of the STEM Auction):

- bid their minimum generation at the price floor (to avoid infeasible dispatch) and any quantities above that generation at the relevant SRMC when they expect the Balancing Price to be high enough to make an overall profit; and
- bid all their generation capacity at the price cap if they expect the Balancing Price to be too low to make an overall profit.

Therefore, the Rule Change Panel considers that efficiencies can be created by providing Market Generators with more up to date price and load forecasts to inform better decision making about positioning their Price-Quantity Pairs.

However, the Rule Change Panel notes that more accurate forecasting and responding closer to real time may, but will not necessarily, reduce the aggregate ramping issue in the WEM. The result of Market Participants re-positioning their Balancing Price-Quantity Pairs at the price floor or cap and its effect on the aggregate ramp of IPPs will depend on the generation mix that is cleared to supply the market and changes in demand in the relevant Trading Interval.

6.1.3.2 Analysis of Increases in Forecast Accuracy with a BGC Closer to Real Time

Approach to the Analysis

The Rule Change Panel analysed whether forecast accuracy increases the closer the forecasting time is to real time. The Rule Change Panel considered the following variables:

- LSG, which is the actual generation attributable to Scheduled Generators in the SWIS, measured in MW;
- Non-Scheduled Generation (**NSG**), which is the total end of interval quantity attributable to Non-Scheduled Generators in the SWIS, measured in MW, and reflecting information provided in Market Participants Balancing Submissions; and
- Final Price, which is the final Balancing Price, representing the cost of providing the balancing energy, measured in $/MWh.

Actual values for each of these variables were extracted for each Trading Interval in the 2017 to 2019 period from the Balancing Market summaries available on AEMO's website.[16] AEMO provided the Rule Change Panel with twenty forecasts for each actual value of Total Generation, NSG, and Final Price, representing a forecast for each of the 30-minute Trading Intervals in the 10-hour lead up to the delivery interval.[17]

16 See http://data.wa.aemo.com.au/#balancing-summary.

17 AEMO publishes the BMO in half-hourly intervals.

Forecast LSG was calculated by subtracting each forecast of NSG from the corresponding forecast of Total Generation for each of the 20 forecasts, for each delivery interval.

The NSG values were also used to calculate a persistence forecast (**Persistence NSG**), which was the forecast for a target delivery interval based on the actual NSG observed in the preceding Trading Interval, measured in MW.[18]

Errors in forecasting were calculated for each variable by subtracting each forecast value (i.e. in each 30-minute Trading Interval leading up to the delivery interval) from the actual value in the delivery interval (i.e. forecast error = forecast – actual).

The absolute values of the errors were calculated and the Mean Absolute Error (**MAE**)[19] was derived for each of the twenty forecasts by taking the absolute value of the forecast errors in each calendar year and then averaging across all Trading Intervals for each forecast ahead of the delivery interval.

Comparisons were then made to see whether there were differences in accuracy between the forecasts for each of the differing BGC options (i.e. at 2 hours, 90 minutes and 60 minutes). To do this, difference in absolute error distributions were calculated by subtracting the absolute values of the errors for the forecasts at one BGC from the absolute value of the errors for the forecasts at a shorter BGC.

A bootstrapping percentile method[20] was then used to calculate 99% confidence intervals for the medians of the difference in absolute error distributions[21] to determine whether the confidence intervals:

- contained a median of 0 MW, which would indicate that there is no significant difference in the absolute values of the errors in forecasting between BGC options; or
- did not contain the median of 0 MW, which would indicate that there is a statistically significant difference in the absolute values of the errors in forecasting between the BGC options.

Results of the Analysis

The results of the analysis showed that the accuracy of Final Price and NSG forecasts do not increase significantly closer to real time.[22]

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18 AEMO previously provided the Rule Change Panel with forecast NSG data for the 2016 period, which was included in this analysis.

19 MAE was used because positive and negative values cancel out when averaged. For example, if one error is 6 MW and another error is -6 MW, the average error is zero. This does not show the range of errors, which is actually 6 MW in both directions. Additionally, the Mean Absolute Percent Error (MAPE) can be misleading because, if prices are close to zero, MAPE values can be large regardless of the actual absolute errors. If prices spike, resulting MAPE values are small. MAPE for negative prices are difficult to interpret.

20 Bootstrapping is a 'sampling with replacement' technique in which 1,000 random samples from the "Difference in Absolute Error" distributions were used to produce a 'bootstrap' distribution of the median difference values. The Bootstrap percentile method was then used to calculate 99% confidence intervals for the medians. If the confidence interval included a median of 0, the null hypothesis (i.e. that there is no difference between the absolute errors in forecast between the gate closure options) was accepted. If the confidence Interval did not contain a median of 0, then the alternative hypothesis (i.e. that there is a difference between the absolute errors of the forecasts for the different BGCs), was accepted.

21 Median differences were considered rather than mean differences, as the forecast distributions were highly leptokurtic (packed very closely around the mean), with lots of outliers that were skewed in a negative direction (i.e., the forecast Total Generation tended to be more incorrect when it was greater than the actual Total Generation).

22 The Rule Change Panel notes that, for the Trading Intervals considered in this analysis, Market Participants were not allowed to change their NSG forecast after BGC and therefore the NSG forecast cannot increase in accuracy closer than two hours to real time.

Additionally, it was found that:

- up until two hours before the start of the relevant Trading Interval the NSG forecast is more accurate than the Persistence NSG forecast; and
- Market Participants did not usually update their initial Balancing Submission to reflect changes in their NSG forecast.

It does not make sense to compare the accuracy of the NSG forecast and the Persistence NSG forecast closer to real time than two hours, as Market Participants were not allowed to update their Balancing Submissions to reflect an updated NSG forecast past BGC. However, with this in mind, the Rule Change Panel considers it likely that the Persistence NSG forecast would be more accurate than the NSG forecast from around 90 minutes before the start of the Trading Interval.

This means that a Persistence NSG forecast would only provide better value than the NSG forecast if the BGC was reduced to 60 minutes or less because if the BGC was 90 minutes any Balancing Submission would need to be made before BGC and therefore before the Persistence NSG forecast becomes more accurate than the NSG forecast. The Rule Change Panel notes that with increasing wind generation in the generation mix, any forecast of Non-Scheduled Generation (NSG forecast and Persistence NSG) becomes more volatile.

In contrast to this, there were statistically significant increases in accuracy closer to real time in LSG forecasts. The median differences between absolute errors in LSG forecasts were:

- 4.62 MW for the comparison of the forecast for the 120-minute BGC and the forecast for the 30-minute BGC;
- 2.58 MW for the comparison of the forecast for the 120-minute BGC and the forecast for the 60-minute BGC;
- 1.34 MW for the comparison of the forecast for the 120-minute BGC and the forecast for the 90-minute BGC; and
- 1.04 MW for the comparison of the forecast for the 90-minute BGC and the forecast for the 60-minute BGC.

The Rule Change Panel notes that the findings of its analyses are consistent with AEMO's findings, as presented in its first period submission, which show that (based upon 2016 data) the accuracy of demand forecasts in 2016 improved as the delivery interval approached.

The Rule Change Panel notes that, while statistically significant, the improvements in forecast accuracy for LSG are relatively modest when compared to the range of errors observed in forecasting LSG. The Rule Change Panel therefore concludes that moving the BGC closer to real time will increase the accuracy of LSG forecasts but that the benefit in terms of the forecast quantity will be relatively modest. However, the Rule Change Panel considers that even small discrepancies in quantities can have large implications if price forecasting is inaccurate.

Appendix C provides further discussion of the results of the statistical analysis, including charts illustrating the results.

6.1.3.3 Quantifying the Benefits of a Shortened BGC for Consumers and Market Outcomes?

The Rule Change Panel agrees with Alinta, AEMO, Bluewaters and Perth Energy that the benefits of the proposal are that it will allow Market Participants to respond more dynamically to changing market conditions by providing access to more accurate forecasts closer to real time for use in making trading decisions (see section 5.2.3).

The Rule Change Panel considers that this outcome will be promoted by clause 7A.2.8 and 7A.2.9, which require that Market Participant's, including Synergy, must ensure that their most recent Balancing Submissions accurately reflect all information reasonably available to them, including Balancing forecasts. Together, a reduced BGC and the obligations on Market Participants will reduce risk and create efficiencies, lowering costs for consumers.

However, in its first period submission, AEMO noted that it was not aware of a reliable method of translating the reductions in forecast error into estimates of market-wide cost savings and that attempts to quantify the savings would require speculative assumptions about how Market Participants would change their behaviour and any risk premiums they incorporate in their Balancing Submissions.

The Rule Change Panel agrees with AEMO and notes that options for assessing the benefits of changes to gate closures can include the use of estimates[23] or market simulation using a production cost model, both of which are only as accurate as the assumptions that are input to the analyses. Moreover, the accuracy of market simulation is reduced in the WEM because of Synergy's Portfolio bidding, and such simulations are time consuming and costly when considered in the context of the impending reforms under the ETS.

Accordingly, the Rule Change Panel's assessment of this Rule Change Proposal is based on stakeholder feedback in response to the first submission period, MAC meetings and workshops, and one-on-one stakeholder discussions. Amendments to the Market Rules are assessed against the Wholesale Market Objectives and the principles that underlie them.

6.1.3.4 What Impact will Moving the BGC Closer to Real Time Have on AEMO?

The Rule Change Panel notes that AEMO already has access to real time SCADA data (i.e. every 4-seconds) from each Facility, including Non-Scheduled Generation, that it uses to balance supply and demand, and will not have access to more accurate information if the BGC is reduced.

While AEMO is already able to do what it needs to do to manage system security and reliability within the current Market Rules, the Rule Change Panel considers that moving the BGC closer to real time will compress the time frame that AEMO has available to fulfil its functions in a normal operating state. There is a trade-off between providing more accurate information to Market Participants through shifting the BGC closer to real time and providing AEMO with sufficient time to fulfil its System Management functions, given the systems that it has available to meet these functions.

The Rule Change Panel considers that it is critical for AEMO to have the time that it needs to fulfil its System Management functions under the Market Rules. AEMO has indicated that it will have sufficient time to fulfil its System Management functions at a 90-minute BGC.

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23 See Electricity Authority (2015) Shortened Gate Closure and Revised Bid and Offer Provisions Consultation Paper and Decision Paper https://www.ea.govt.nz/search/?q=Shortened+gate+closure&s=&order=&cf=&ct=&dp=&action_search=Search.

See also: Facchini, Rubino, Caldarelli and Di Liddo (2019) Changes to Gate Closure and its impact on wholesale electricity prices: The case of the UK, Elsevier Vol. 125, pp 110-121.

6.1.4 Existing Options for Addressing the Aggregate Ramp Issue

6.1.4.1 Is Constraining IPP Facility Ramp Rates an Option for Addressing the Aggregate Ramp Issue?

At the 6 September 2019 MAC workshop AEMO noted that it could constrain the ramp rates of IPP Facilities to respond to the aggregate ramp issue (see slide 3, section 5.5.1.3). However, in the 18 October 2019 MAC workshop (section 5.5.2) and in out of session consultation with AEMO (section 5.7.1.1), AEMO considered that constraining IPP Facilities was not an option for addressing the aggregate ramp issue. The reasons provided by AEMO included that:

- issuing Dispatch Instructions to constrain non-Synergy Facilities that are causing the aggregate ramp issue is effectively linear dispatch;
- if AEMO gets into a High Risk Operating State because of an action that AEMO has taken in the first instance, it becomes conflicted because it then needs to constrain non-Synergy Facilities because of AEMO's actions;
- constraining non-Synergy Facilities would conflict with the Market Rules because it would require Out of Merit Dispatch, which can only be used to avoid a High Risk Operating State; and
- the Market Rules require that AEMO should maintain in-merit dispatch as a priority over reverting to Out of Merit Dispatch and should therefore pursue options that do not trigger the need to issue Dispatch Instructions Out of Merit.

AEMO concluded that implementing a linear ramping solution would enable a 60-minute BGC because dispatch under this solution would remain in-merit, whereas selectively constraining IPP Facilities would not.

In the 1 May 2017 MAC meeting, Mr Stevens noted that System Management is able to constrain IPPs on or off in aggregate ramp situations rather than risking Power System Security to follow the merit order (see section 5.1.1.2). The Rule Change Panel agrees with Mr Stevens and notes that the ramp rates of IPPs can be constrained by reducing the ramp rate, reducing End of Interval targets, or delaying ramping altogether.

In contrast to AEMO, the Rule Change Panel considers that AEMO's ability to constrain individual IPP ramp rates in the first 10 minutes of a Trading Interval is a different option for addressing the aggregate ramp issue than constraining the ramp rates of all IPPs across an entire Trading Interval under the linear ramping solution described by AEMO.

Moreover, the Rule Change Panel considers that it is unclear why AEMO suggests that it is conflicted and unable to constrain individual IPP ramp rates due to AEMO having 'caused' an aggregate ramp issue when it dispatches Facilities. The Rule Change Panel notes that it is Market Participants that provide ramp rates in their Balancing Submissions and that AEMO is obligated to dispatch according to the BMO.

Furthermore, the Rule Change Panel considers that if the position is taken that AEMO is conflicted because of its obligation to dispatch Market Participants and its requirement to address an aggregate ramp issue resulting from that dispatch, then this conflict will occur regardless of the BGC (i.e. whether 60 minutes, 90 minutes or 2 hours).

The Rule Change Panel agrees with AEMO that, in dispatching Facilities, AEMO should first pursue options that do not trigger the need for Out of Merit Dispatch. However, the Rule Change Panel considers that this does not negate the ability to constrain IPPs when it is necessary. If the network is in a Normal Operating State and there is a potential to enter a High Risk Operating State, then AEMO can take steps to constrain any Facility, including non-Synergy Facilities, to avoid the High Risk Operating State.

The Rule Change Panel notes AEMO's comparison of the benefits of the option for linear ramping at a 60-minute BGC, which it considered would enable in-merit dispatch, against the option to selectively constrain IPP Facilities, which it considered requires out of merit dispatch. However, the Rule Change Panel considers that the option to constrain IPP Facilities already exists in the market and accords with AEMO's past behaviour, where it has chosen to constrain the ramp rates of one or two IPPs where it considered that the Facilities ramp rates were too high.

The Rule Change Panel notes that an automated linear ramping process is not yet implemented in the market and AEMO has not yet determined the detail of how such a process would work. Given this, the Rule Change Panel cannot form a view as to whether linear ramping is a better solution to the aggregate ramp issue than constraining IPPs.

Moreover, the Rule Change Panel considers that constraining only the individual Market Participants that are causing an issue, for the duration of that issue, may result in lower constrained off payments than would occur with a linear ramping solution in which the ramp rates of all Market Participants are constrained for an entire Trading Interval.

6.1.4.2 The Use of LFAS to Offset the Aggregate Ramp Issue

AEMO's Interpretation of the Derivation of the LFAS Requirement

AEMO considers that the Market Rules prevent it from using LFAS to address the aggregate ramp issue and that this is the main challenge for shortening the gate closure. However, the Rule Change Panel has legal advice to the contrary.

The Rule Change Panel notes that the Load Following Service is defined in clause 3.9.1 as the service of frequently adjusting the output of one or more Scheduled Generators or the output of one or more Non-Scheduled Generators, within a Trading Interval so as to match total system generation to total system load in real time to correct any SWIS frequency variations.

The Rule Change Panel considers that AEMO's use of LFAS to cover fluctuations due to generation ramping (including the aggregate ramping of IPPs) to date is consistent with this definition, which refers to the correction of <u>any</u> SWIS frequency variations and does not specify a cause (i.e. whether the variation is due to instructed or uninstructed fluctuations).

The Rule Change Panel notes that clause 3.11.1 states that AEMO must determine all Ancillary Service Requirements in accordance with the SWIS Operating Standards and the Ancillary Service Standards. The Ancillary Service Standards are set out in section 3.10 of the Market Rules. Clause 3.10.1(a) sets the standard for Load Following Service, as the level sufficient to provide Minimum Frequency Keeping Capacity, which is the greater of:

- 30 MW; and
- the capacity sufficient to cover 99.9% of the short-term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1-minute average readings around a thirty minute rolling average.

AEMO considers that the derivation of the LFAS Requirement under clause 3.10.1 'expressly excludes' instructed movements for Scheduled Generators. However, the Rule Change

Panel considers that clause 3.10.1 omits mention of instructed movements for Scheduled Generators, rather than explicitly stating that they cannot be included in the LFAS Requirement.

The Rule Change Panel considers that if the LFAS Requirement expressly excluded instructed movements of Scheduled Generators, then AEMO's current use of LFAS to address instructed fluctuations would be a compliance issue, requiring an amendment to the Market Rules.

The Rule Change Panel considers that the standard for Load Following Service is the minimum standard and does not set the maximum level of LFAS capacity that System Management is permitted to procure (e.g. see clause 3.11.3, which allows System management to reassess the level of Ancillary Service Requirements). The Rule Change Panel notes that the standard for the Load Following Service set out in clause 3.10.1(a) has never been employed as the maximum LFAS Requirement, as it would not provide sufficient LFAS capacity to cover the range over which frequency keeping capacity is required.

The Rule Change Panel considers that, while clause 3.10.1 appears to qualify the definition of Load Following Service as the service of frequently adjusting output to only cover uninstructed output fluctuations from Scheduled Generators, System Management must also consider the SWIS Operating Standards in determining the Ancillary Service Requirements.

The SWIS Operating Standards are set out in clause 3.1 and include the frequency standards in the Technical Rules (clause 3.1.1 of the Market Rules). That is, LFAS is used to restore frequency and keep it within the normal frequency band of 49.8 to 50.2 Hz for 99% of the time. The determination of Ancillary Service Requirements by AEMO is therefore broader than the Minimum Frequency Keeping Capacity and should include sufficient Load Following Service to ensure that the frequency standards for the network are met.

Moreover, clause 3.3.2(c) notes that when the SWIS is in a Normal Operating State, System Management must schedule and dispatch Ancillary Services in accordance with the Ancillary Service Requirements (i.e. both the Operating Standards and the Ancillary Service Standards).

For the reasons outlined above, the Rule Change Panel considers that the Market Rules allow AEMO to use LFAS to address the aggregate ramp issue, which accords with AEMO's current practice, within the current market design.

AEMOs Other Assumptions Regarding LFAS

The Rule Change Panel considers that it is unclear why AEMO would consider that it is acceptable to use LFAS to address the aggregate ramp issue under the Market Rules if the BGC is set at 90 minutes, but not if the BGC is set at 60 minutes. The standard for Load Following Services in the Market Rules is not specified differently for differing gate closures.

It is also not clear to the Rule Change Panel how AEMO can choose to allow a small impost on the use of LFAS to address the ramping of generators (e.g. up to 10 MW/minute) but not allow a larger impost, as the standard for Load Following Services in the Market Rules does not limit the use of LFAS on the basis of generator ramp rates.

The Rule Change Panel further considers that if AEMO has reached the opinion that the use of LFAS to facilitate the market is a design flaw, then AEMO should develop a plan for how the market should be redesigned so that LFAS is not employed to facilitate the market (including use of linear ramping if necessary), consult on that plan with all Rule Participants via the MAC, and develop and submit a Rule Change Proposal to address the flaw.

6.1.5 Increased Requirement for LFAS at a 60-Minute BGC

The Rule Change Panel notes AEMO's view that the system responds in real time such that any supply-demand imbalances that remain after the dispatch of the Balancing Portfolio, are managed by LFAS and accordingly under a 60-minute gate closure, relying on LFAS will increase LFAS costs and result in Power System Security risks.

The Rule Change Panel agrees with AEMO that some increase in the LFAS Requirement may result from a move to a 60-minute BGC, particularly if, as AEMO claims, it is unable to reconfigure the Balancing Portfolio to offset the aggregate ramp issue in the same way that it can at a 2-hour or 90-minute BGC.

However, the Rule Change Panel notes that it is impossible to determine exactly what the increase in the LFAS Requirement will be, as Synergy's Ancillary Service generators simultaneously provide Balancing and Ancillary Services (including LFAS, Spinning Reserve and LRR), and supply energy balancing services for the Balancing Portfolio.[24] However, this task may become easier as other participants increasingly provide LFAS.

It is not clear to the Rule Change Panel what system security risk would occur, as under clause 3.11.3, if System Management considers that a considerable shortfall of any Ancillary Service relative to the applicable standard is occurring, or is likely to occur before the next annual update, it can reassess the level of the requirement for that Ancillary Service at that time and procure additional Ancillary Services.

6.1.6 Assessment of the Frequency of the Need for Linear Ramping

AEMO undertook an analysis of the frequency of the need for linear ramping for the 60- and 90-minute BGC options, using data for each Trading Interval in 2018/19.[25]

AEMO's analysis considered whether the Balancing Portfolio ramp rate in each Trading Interval was high enough to offset the residual aggregate ramp rate of IPPs (or overshoot) after the aggregate ramp rate of IPPs met the ramp rate of demand, or whether linear ramping would be required.

As noted in its presentation at the 6 September 2019 MAC workshop (see section 5.5.1.3, slides five and six), AEMO noted that when it assessed the Balancing Portfolio ramp rate capabilities, it excluded any machines that were providing LFAS because these machines cannot respond to an unscheduled movement if they are responding to a scheduled movement.

The Rule Change Panel considers that this proposition can lead to incorrect conclusions. This is because the Facilities respond to changes in frequency resulting from the combined influence of changes in supply and demand that occur concurrently in time, irrespective of whether they are the result of scheduled or unscheduled generation movements.

Moreover, the Rule Change Panel considers that a scenario whereby LFAS machines are set aside to only address selected types of fluctuations in the balance between supply and demand would pose a significant risk to system security and is impossible to achieve without

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24 Refer to System Management's Ancillary Service Report for the WEM 2019, Appendix 1, page 21. https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf.

25 AEMO provided the Rule Change Panel with an overview of AEMO's assumptions, the formula that it used for this assessment, and a spreadsheet demonstrating the application of this formula to the 60-minute BGC option but only for the Trading Intervals that AEMO identified in its assessment as requiring linear ramping.

making major changes to the way that the system operates, given the automaticity of Ancillary Services.[26]

AEMO's analysis of gate closure options assumed that, at the 90-minute BGC, it would have the same ability to meet the requirements of the market as it currently has at a 2-hour BGC.[27] That is, AEMO did not consider that the half-hour period that it would lose with a shift to a 90-minute BGC (from the 2-hour BGC) would have any effect on its ability to move coal plant ahead of the Trading Interval to reposition the Balancing Portfolio to offset the aggregate ramp issue.

Therefore, AEMO's analysis of the 90-minute BGC option can be considered to be equivalent to an assessment of the current BGC option. Based on its analysis of the 90-minute BGC option, AEMO found that in the 2018/19 period, linear ramping would have been required in 7% of Trading Intervals.

However, the Rule Change Panel notes that AEMO did not actually need to use linear ramping, requiring the placement of constraints on the ramp rates of all Market Participants across a 30-minute Trading Interval, in 7% of Trading Intervals in 2018/19 and that the market continued to function effectively.

In the 18 October 2019 MAC workshop, AEMO noted that it had not used linear ramping on a regular basis, but when it did, the linear ramping involved constraining the ramp rates of only one or two Facilities that were causing a ramping issue, and not AEMO's new automated linear ramping solution (or a manual version of it). AEMO noted that it had never encountered a situation where five IPPs were causing an excessive ramp issue at the same time.

For its analysis of the 60-minute BGC option, AEMO assumed that its only tool to offset the aggregate ramp of IPPs would be to reconfigure the Balancing Portfolio within the Trading Interval (see section 5.5.2). That is, AEMO assumed that it would no longer be able to:

- move Synergy's coal plant ahead of the Trading Interval to make way for gas plant;
- constrain IPP Facilities; or
- rely on LFAS to address any remaining imbalance between the ramp rates of IPPs and demand that the Balancing Portfolio is unable to offset.

Based on its analysis of the 60-minute BGC option, AEMO found that in the 2018/19 period, linear ramping would have been required in 11% of Trading Intervals.

However, the Rule Change Panel considers that AEMO can constrain IPP Facilities that cause excessive ramping issues (see section 6.1.4.1) and AEMO can rely on LFAS to address any remaining imbalance between the ramp rates of IPPs and demand that the Balancing Portfolio is unable to offset (see section 6.1.4.2).

Therefore, the Rule Change Panel concludes that the approach that AEMO used to assess when linear ramping is necessary is overly conservative because it:

- was based on improbable assumptions about the way that the market operates in real time;

26 That is, through governor response and AGC.

27 AEMO considered that it would have 20% more ramp rate at the 90-minute BGC than at the 60-minute BGC due to the ability to move coal plant prior to the delivery interval. The value of 20% was determined arbitrarily and AEMO noted that it conducted a sensitivity test of the analysis at 15% and 25%. The Rule Change Panel has been unable to verify this analysis.

- identified a requirement for linear ramping in the 2018/19 period irrespective of whether it was actually needed; and
- unnecessarily limited the options available to AEMO for offsetting imbalances between the aggregate ramping of IPPs and the ramp rate of demand.

The Rule Change Panel acknowledges that establishing the likely requirement for linear ramping is a difficult task. The data needed to determine the frequency of the aggregate ramp issue is either not collected by AEMO or is confounded. For example, it is impossible to determine from the available SCADA or Dispatch Instruction data how much or how often:

- The Balancing Portfolio is currently moved specifically to address the aggregate ramp issue:
    - within a Trading Interval, because energy provided by Synergy for balancing and LFAS are indistinguishable, as the same units provide both services, as well as Spinning Reserve and LRR, which are triggered automatically with changes in frequency; and
    - ahead of the delivery interval, with coal plant moved up or down specifically to enable positioning of gas plant to offset the aggregate ramp of IPPs at the start of the Trading Interval.
- LFAS under AGC is currently employed to offset the imbalance in ramping between demand and IPPs that is not able to be met by the Balancing Portfolio at the start of a Trading Interval.
- IPPs are constrained (either through adjustments to their ramp rates or End of Interval targets or through maintaining a constant ramp rate) specifically for the purpose of the aggregate ramp issue.

The Rule Change Panel therefore considers that any assessment of the incidence of the aggregate ramp issue will be theoretical in nature and may not necessarily represent what is happening now or will happen in the future under any of the gate closure options.

6.1.7 The Effects of an Increasing Penetration of Renewables on the Market

6.1.7.1 Technological Developments in the WEM

The Rule Change Panel agrees with AEMO's, Perth Energy's and Synergy's observations regarding the detrimental effects of an increasing penetration of renewables on forecasting in the WEM; and with AEMO's view that shortening the BGC will be consistent with these technological developments.

The International Energy Agency (**IEA**) assessed other jurisdictions, including Great Britain, Texas, California, South Africa, Brazil and Germany to identify a high penetration, benchmark renewable energy market design.[28] The IEA noted that, in the past, there was relatively stable demand, baseload operated as baseload and low mid-merit, and generation comprised mainly conventional plant. Given the longer timeframe for system and market operations, energy and Ancillary Services could be run separately, using manual processes.

[28] See: IEA, Electricity market design and Renewable Energy (**RE**) Deployment (RES-E-MARKETS), September 2016; See also: KPMG, Electricity Market Design Principles – identifying long-term market design principles to support a sustainable energy future for Australia April 2018.

Traditional Ancillary Services to arrest frequency excursions included LFAS and Spinning Reserve Service.

In contrast, the IEA found that in the benchmark renewable design demand is characterised by the 'duck curve', coal plant operating in mid-merit or peaking mode, conventional generation giving way to resources that provide flexibility to respond to volatile demand, and energy and Ancillary Services are co-optimised and include new services for inertia, fast frequency response and generator ramping capability.

The Rule Change Panel notes that the WEM is situated somewhere between the historical and benchmark renewable design. The duck curve is already affecting the WEM, some coal plant operates in mid-merit mode and LFAS is sculpted. The ETS reforms include plans to co-optimise energy and Ancillary Services and to reduce the gate closure to 15 or 0 minutes.

The Rule Change Panel therefore considers that a shortened BGC in the WEM is consistent with changes in market design to accommodate an increasing penetration of renewable technologies observed in other jurisdictions.

6.1.7.2 Increasing Need for LFAS

AEMO noted at the MAC workshops that the availability of LFAS is now more important than before because of the increased frequency and magnitude of unscheduled events (e.g. from wind and solar generation) and with new wind farms (about 400 MW) joining the system in 2020.

The Rule Change Panel notes that the current WEM design was developed when the penetration of renewable generation was much lower and acknowledges AEMO's concern that it may not have enough LFAS to address the aggregate ramp issue, as well as address other imbalances between supply and demand.

However, the Rule Change Panel considers that the effects of an increasing penetration of renewables in the system, including the increased reliance on LFAS, will result regardless of a change to the BGC. Moreover, the Rule Change Panel notes that it is a function of AEMO to ensure that the SWIS operates in a secure and reliable manner (clause 2.2.1), and that there are provisions in the Market Rules to ensure that AEMO is able to do this.

For example, clause 3.11.7A requires Synergy to make its capacity to provide Ancillary Services from its Facilities available to System Management to a standard 'sufficient to enable System Management to meet its obligations' in accordance with the Market Rules. Under clause 2.2.2(a), where Synergy cannot meet the Ancillary Service Requirements, it is a function of System Management to procure adequate Ancillary Services. Clause 3.11.8A allows System Management to procure an Ancillary Service Contract from any Rule Participant, not just Synergy.

AEMO must update the Ancillary Service Requirements on an annual basis, and the requirements must be set based on the Facilities and configuration expected for the SWIS in the coming year (clause 3.11.2.). If AEMO considers that a considerable shortfall of any Ancillary Service relative to the applicable Ancillary Service Standard is occurring, or is likely to occur, before the next update under clause 3.11.2, AEMO may reassess the level of the Ancillary Service Requirements for that Ancillary Service at that time (clause 3.11.3.). There is no restriction on what AEMO can procure but the requirements must be audited and approved by the ERA.

Therefore, the Rule Change Panel considers that if, as AEMO states, the variability of wind and solar generation, and the aggregate ramp issue, are already eating into the required

Ancillary Services that are available to the market, leaving the system exposed to possible contingencies, then it is incumbent on AEMO to remedy this and AEMO has the tools to do so under the Market Rules.

6.1.7.3 Issues Facing the Balancing Portfolio

Synergy has noted that, with the changing SWIS load profile, and as the instances of the Balancing Portfolio being dispatched at minimum generation levels increase, it is unlikely that movements of the Balancing Portfolio will be able to accommodate IPPs moving at maximum-ramp-rates without impacting the provision of Ancillary Services.

Moreover, Synergy considers that it is neither appropriate nor efficient to accommodate IPP movements at their maximum ramp rate through intra-interval adjustments to the Balancing Portfolio that are manifestly inconsistent with the Balancing Portfolio's end-of-interval targets.

The Rule Change Panel notes that in the current market design, Synergy is the default provider of Ancillary Services and must make its capacity to provide Ancillary Services from its Facilities available to AEMO to a standard sufficient to enable AEMO to meet its obligations in accordance with the Market Rules (clause 3.11.7A).

Therefore, the Rule Change Panel understands that an argument could be made that it is Synergy's role to address the aggregate ramp issue. However, as explained below, the Rule Change Panel considers that such an argument may be unreasonable in light of changes in Synergy's ability to recover Ancillary Services costs, changes in the use of Synergy's coal fleet, and the growing incidence of the low load days.

Ancillary Services provided by the Balancing Portfolio are remunerated via an administrative mechanism, as it is impossible to determine the quantities of Ancillary Services that Synergy supplies, with its portfolio of units simultaneously providing energy and Ancillary Services to the market, and energy balancing services to its own portfolio.[29] The compensation paid to Synergy for balancing supply and demand has previously covered all of the Load Following Services that Synergy provides, including the dispatch of Synergy's Balancing Portfolio to offset the aggregate ramp of IPPs when needed.[30] However, other Market Participants have more recently been providing LFAS, so Synergy is remunerated less for providing these services to the market.

The Rule Change Panel notes that Synergy has an aging coal fleet and that the Minister has publicly announced that the first of Muja Power Station's two C units will be retired from October 1, 2022[31] and the second unit will be retired from 1 October 2024.[32] The Minister also noted that two Muja D units and Collie Power Station will continue to operate, with the retirement of Muja C, ensuring that Muja D operates more frequently, increasing its stability and long term viability.

29 See System Management's Ancillary Service Report for the WEM 2019, Appendix 1, pp.21 https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf

30 See the 'Ancillary Services Report for the WEM 2019,' Appendix A, page 21 https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf.

31 See Media Statement: https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/Muja-Power-Station-in-Collie-to-be-scaled-back-from-2022.aspx

32 See response to Question on Notice 2192 http://www.parliament.wa.gov.au/parliament/pquest.nsf/viewLAPQuestByDate/62E9D738B3A19ADA48258410002133F9?opendocument

The Rule Change Panel considers that it is reasonable to assume that Synergy will attempt to maximise the use of its remaining coal Facilities across the next decade[33] and that the issues experienced by Synergy on low load days will increase for Synergy with a reduced BGC.

For example, at a 60-minute BGC, in some Trading Intervals, it is likely that AEMO will be unable to move Synergy's coal plant ahead of the delivery interval to bring gas units on to offset the aggregate ramp of IPPs. This may increase the duty on the Balancing Portfolio, which would need to be reconfigured to offset the aggregate ramp of IPPs and, at the same time, the Balancing Portfolio would be called upon to act as the default provider of LFAS (when others are not cleared to provide LFAS or are otherwise unable to provide that service) and other Ancillary Services.

Such a scenario may be exacerbated by the current trend of an increasing number of low load days due to changing demand and a high penetration of rooftop PV, although it is not clear to the Rule Change Panel the extent to which this trend will continue in the near future in the SWIS. [34]

The Rule Change Panel does not consider that it is reasonable to increase the balancing duties of the Balancing Portfolio and require it to move at ramp rates greater than the Ramp Rate Limit in Synergy's Balancing Submission to address the aggregate ramp issue at a time when the Balancing Portfolio is increasingly incapable of doing so, and when Synergy may be unable to recover its costs.

6.1.8 AEMO's Linear Ramping Solution

6.1.8.1 The Need for Automation of Linear Ramping at a 60-Minute BGC

Human Capabilities

AEMO suggested that automated linear ramping is required at a 60-minute BGC because it is beyond the capability of a human to deal with linear dispatch in this short period of time. The Rule Change Panel agrees that the complex automated linear ramping solution described by AEMO (i.e. requiring calculation of adjusted ramp rates for all Market Participants and input to the RTDE) may be beyond the capacity of a human to implement at a 60-minute BGC.

However, it is not clear to the Rule Change Panel that the complex automated linear ramping solution described by AEMO, that constrains all IPPs for an entire Trading Interval, is

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33 This is consistent with the operation of Synergy's coal plant in mid-merit and peaking modes rather than as baseload.

34 There are a number of factors that may mitigate the decline in daytime demand, including:

- The Federal and State Government responses to the COVID-19 pandemic, with both implementing strict self-isolation rules and restricting activities to essential services. This should result in a shift in demand to residences from businesses, small to medium enterprises and industry (See Australian Energy Council's 2020 Energy Insider 2 April 2020: Energy demand – flattening the curve?). Further, the COVID-19 pandemic is expected to have a significant negative impact on the global and Western Australian economies, which is likely to reduce household incomes and may dampen the uptake of rooftop solar PV.
- The Western Australian Government released the Distributed Energy Resources (**DER**) Roadmap on 4 April 2020 (https://brighterenergyfuture.wa.gov.au), where the Government recognised that the speed and scale of uptake of DER (such as rooftop solar PV) is reducing daytime demand to levels where significant risks to the security and reliability of the SWIS could occur by around 2022 if steps are not taken to manage the situation. The DER Roadmap specifies a set of 36 actions to address these risks, such as the installation of distribution batteries by Western Power and the running of a pilot of time-of-use retail tariffs.

necessary at a 60-minute BGC and why the process that has been used in the past cannot continue to be used at a 60-minute BGC.

The Rule Change Panel notes the observations by:

- Alinta, that even in the current circumstances there can be late bona fide changes to offers close to real time and System Management is able to manage these effectively (see section 5.2.4.1);
- Perth Energy, that System Management has accepted the high-level design of Western Power's GIA solution, which includes the need for AEMO's operators to continually assess and accommodate short-term changes in dispatch every few minutes (see section 5.2.2); and
- AEMO, that controllers can determine when the aggregate ramp may be an issue and address it by constraining the one or two Facilities that are causing an excessive ramp issue within a limited timeframe, and that it has never experienced a scenario where five other machines were ramping at the same time.

Therefore, the Rule Change Panel considers that AEMO can address the current aggregate ramp issue at a shorter BGC and that, if AEMO believes that the aggregate ramping of more than one or two Facilities will be an issue in the future, AEMO should provide input to the ETS reform program or submit a Rule Change Proposal to address this future concern.

Picking Winners and Losers

The Rule Change Panel notes AEMO has reasoned that automation of linear ramping is needed to remove the risk of discretionary outcomes (i.e. picking winners and losers).

It is not clear to the Rule Change Panel why the issue of AEMO 'picking winners and losers' must be contemplated at a 60-minute BGC, but it has not been raised as an issue at the current BGC in the instances when AEMO has decided to constrain the ramp rates of particular Facilities that were seen to be causing an excessive ramp issue.

The Rule Change Panel notes AEMO's intention for the automatic linear ramping process to constrain all Market Participants across an entire Trading Interval. The Rule Change Panel considers that this decision itself creates winners and losers:

- a Market Participant that causes the issue will win, as it will not be constrained as much because all other generators will also be constrained; and
- Market Participants that do not cause the issue will lose, as they are being constrained for something that is beyond their control.

The Rule Change Panel notes that the decision to constrain all Market Participants across an entire Trading Interval is also contrary to the causer pays principle.

6.1.8.2 How Will Automated Linear Ramping Work?

The Rule Change Panel notes that AEMO is unclear on the details of how its automated linear ramping process will work. For example, AEMO noted that it would not build a separate automatic linear ramping tool, but it has not yet determined the detailed design of the systems and processes within existing systems that it will use to give effect to this process.

AEMO also noted that, as part of this process, it will issue every non-Synergy Facility a Dispatch Instruction to go to a point at the end of the interval via a ramp rate determined by AEMO, which will be calculated by taking the change in quantity over the interval and dividing it by the number of minutes left in the interval. However, the Rule Change Panel notes that it is not clear by how much each Facility will be constrained, and on what basis (i.e. will every Facility be constrained by the same amount or will ramp rates be constrained based on ramp rate capabilities, or in proportion to a Facility's size?).

AEMO has also noted that non-Synergy Facilities will be dispatched linearly to a target at the end of the Trading Interval and that the Balancing Portfolio will be dispatched in the opposite direction to offset the aggregate ramp of IPP Facilities.

However, the Rule Change Panel notes that it is not clear how Synergy will be dispatched within the Trading Interval. LFAS machines are under AGC and will ignore the RTDE instructions and follow the frequency (dispatched every 4-seconds), while other Facilities in the Balancing Portfolio will be required to be dispatched by the RTDE to a target on a 10-minute dispatch cycle to offset the linear ramp of IPPs.

The Rule Change Panel considers that this will be a complex process, given variable demand within a Trading Interval (e.g. due to wind and solar), and a 10-minute dispatch cycle, possibly requiring large volumes of LFAS to balance the system and to ensure that Synergy meets its target at the end of the Trading Interval, potentially making linear ramping a costly solution.

The Rule Change Panel also notes that in discussion at MAC meetings (see the 1 May 2019 MAC meeting minutes, section 5.1.1), AEMO indicated that changes were needed to prevent constraint payments, which would result as an unintended consequence of implementing linear ramping (see section 5.2.3). Despite this warning, AEMO's linear ramping solution estimates increases in constraint payments of $1 million to $3 million per annum (see section 6.6.1.4).

The Rule Change Panel considers that questions of the cost and practicality of AEMO's linear ramping solution, even whether it is a viable option, cannot be answered if AEMO does not know how the linear ramping mechanism will work. Nevertheless, the Rule Change Panel considers that the complex linear ramping process described by AEMO appears:

- unnecessary, as there are other options available to AEMO to address ramping issues;
- lengthy, given the timeframe of the ramping issue, which occurs in the first 10-minute dispatch cycle;
- unfair, as it penalises Market Participants that are not causing ramping issues;
- potentially costly, given the need for increased LFAS and constraint payments; and
- technically challenging.

Accordingly, the Rule Change Panel cannot support a BGC option under which AEMO intends to implement this process.

6.1.9 The Rule Change Panel's Draft Decision on BGC Options

The Rule Change Panel considers that it is possible to increase LSG forecast accuracy by moving to a 90-minute BGC, which has little in the way of cost and practicality implications (see section 6.6).

However, the possible costs and timeframe associated with a move to a 60-minute BGC may outweigh the benefits achievable at this gate closure, particularly if AEMO pursues linear ramping as a result of the move to a 60-minute BGC (see section 6.1.6 for discussion of AEMO's views on linear ramping).

Therefore, the Rule Change Panel's draft decision is to move to a 90-minute BGC.

In relation to this, the Rule Change Panel notes that clause 7A.1.16 requires AEMO to determine a point in time immediately before the commencement of a Trading Interval for the purpose of setting the BGC, which must be no shorter than two hours and no longer than six hours before the commencement of a Trading Interval. That is, the Market Rules currently provide AEMO with the flexibility to set the BGC within set gate closure time limits and do not specify that the BGC must be 2 hours. Consequently, the specification of a fixed 90-minute BGC will remove AEMO's discretion to change the BGC.

6.2 Additional Issues Identified by the Rule Change Panel

The assessment of the additional issues identified by the Rule Change Panel and the rationale for the Rule Change Panel's draft decision on these matters are set out below. In summary, the Rule Change Panel proposes to:

- set Synergy's gate closure for the Balancing Market to 150-minutes and implement a rolling gate closure for Synergy, instead of the current restriction on Synergy to bid in blocks; and
- set the LFAS Gate Closure to 210-minutes for both IPPs and Synergy, with the requirement for block bidding remaining but being reduced from six to four hours.

6.2.1 Synergy's Gate Closure for the Balancing Market

6.2.1.1 Forecasting Accuracy

The same approach to analysis of forecasting error that was employed to assess increases in forecasting accuracy from a reduction in the BGC was employed to assess increases in forecasting accuracy from moving Synergy's gate closure for the Balancing Market closer to real time (see section 6.1.3.2).

The results again showed that there were statistically significant increases in accuracy closer to real time in LSG forecasts. The median differences between absolute errors in LSG Forecasts were:

- 8.6 MW for delivery in the first Trading Interval in the Balancing Horizon, for the comparison of the forecast for Synergy's current gate closure for the Balancing Market (i.e. 240 minutes) to the proposed 120 minute gate closure option (i.e. one hour ahead of a 60-minute BGC); and
- 7.3 MW for delivery in the first Trading Interval in the Balancing Horizon, for the comparison of the forecast for Synergy's current gate closure for the Balancing Market (i.e. 240 minutes) to the proposed 150-minute gate closure option (i.e. one hour ahead of a 90-minute BGC).

Appendix C provides further discussion of the results of the statistical analysis, including charts illustrating the results.

6.2.1.2 Should Synergy have the same Gate Closure as IPPs?

The Rule Change Panel agrees with AEMO that market efficiency will be improved when all Market Participants are able to make operational decisions with the most accurate available information. The potential efficiency benefits of allowing participants to respond to later, more accurate forecasts also apply to the Balancing Portfolio.

However, the Rule Change Panel notes that while Synergy considered that it should have the same BGC as IPPs, Alinta and Bluewaters considered that Synergy's gate closure should be as close as possible to the BGC, as this would be most efficient for the market, but should not be the same as for IPPs due to issues with market power.

The Rule Change Panel notes that the risk to IPP's of being caught in infeasible dispatch and having to pay refunds is greater if they do not have forewarning of what the Balancing Portfolio will do. The Rule Change Panel therefore agrees with Alinta and Bluewaters that it is important that IPPs are able to update their Balancing Submissions having seen the final position of the Synergy Portfolio, which should be allowed for when setting the gate closure timeframes.

6.2.1.3 What Do IPPs Need to do between Synergy's Gate Closure and BGC?

The Rule Change Panel considers that the timeframe between Synergy's gate closure for the Balancing Market and the BGC should be as short as possible, allowing just sufficient time for IPPs to do what they need to do to bid efficiently and avoid infeasible dispatch.

The Rule Change Panel notes that Alinta and Bluewaters both considered that Market Participants would have to review prices and internal positions, and potentially submit variation Balancing Submissions to reflect all available information, provide for optimal dispatch based on costs, and avoid infeasible dispatch.

Alinta considered that this process takes at least 60 minutes and that 30 minutes was too short a timeframe, as the Market Rules specify that AEMO has 15 minutes into an interval to publish an updated BMO,[35] which may give participants only 15 minutes to review and respond to changes (see Appendix B). Bluewaters considered that it takes around 1.5 hours to ensure that all intervals in the short-term horizon are correct.

The Rule Change Panel agrees with Alinta that it should only take up to 60-minutes for IPPs to do what is needed following Synergy's gate closure, given that processing and publication of the BMO is largely automated and that updated forecasts are published every half hour. The Rule Change Panel's draft decision is therefore to move Synergy's gate closure for the Balancing Market to one hour ahead of the BGC (i.e. 150 minutes ahead of the delivery interval).

6.2.1.4 Market Power and Block Bidding Arrangements

The Rule Change Panel notes that AEMO, Alinta, Perth Energy and Synergy suggested that consideration be given to changing the requirement for block bidding by Synergy to a rolling gate closure to allow it to update its Balancing Submissions with changing market conditions (see section 5.2.5).

The Rule Change Panel agrees that the requirement for block bidding is and will continue to become increasingly unworkable as the penetration of renewables gradually increases; and that it does not make sense in terms of system security or efficiency for Synergy to be unable to move its fleet to respond to changing market conditions.

The Rule Change Panel notes that a number of different reasons were offered for why the current block bidding arrangements are in place, including that:

- they are intended to help address Synergy's market power by allowing IPPs to respond to Synergy's bids;

35 See clause 7A.3.1.

- they are intended to encourage Synergy to pull Facilities out of the Balancing Portfolio;
- they have been in place since market start and have not already been changed because:
  - o there has been a reluctance to make large changes to the original market design;
  - o they were needed to facilitate a smooth transition to the new market arrangements without risking system security and reliability;[36] and
- they were introduced as a quid pro quo to offset Synergy's benefits associated with its ability to return Facilities from Outage materially earlier than other Market Participants.

The Rule Change Panel notes that Synergy remains dominant in the market and, unlike all other Market Participants, continues to bid as a Portfolio, so it remains appropriate for IPPs to be able to respond to Synergy's bids. However, the Rule Change Panel agrees with Alinta and Perth Energy that it is not in the market's interest for Synergy to base its bids on potentially highly inaccurate information or for its gate closure restrictions to adversely affect other market outcomes.

The Rule Change Panel notes that Facility bidding by Synergy is an intended outcome of the energy market reforms under the ETS and that, in the past, the requirement for block bidding has not provided an incentive for Synergy to pull its Facilities from the Balancing Portfolio. Additionally, it is not clear to the Rule Change Panel that the information that Synergy uses to bid in each consecutive Trading Interval in the 6-hour block, which becomes increasingly inaccurate with each half-hour increment, necessarily impedes Synergy's market power, so much as it creates inefficiencies.

The Rule Change Panel considers that a one-hour lag in bidding between Synergy and IPPs is sufficient to reduce Synergy's ability to exercise dominance because IPPs can revise their submissions after Synergy's gate closure for the Balancing Market. Moreover, the Rule Change Panel agrees with Synergy that the requirement for all Market Participants to offer at SRMC where the behaviour relates to Market Power currently appears to be a sufficient arrangement to mitigate against market power abuses and result in economically efficient prices and outcomes.

The Rule Change Panel notes that the increase in the accuracy of LSG forecasting of 7 MW is just for the first Trading Interval in Synergy's 6-hour bidding block. Forecasting will also be more accurate for subsequent Trading Intervals within the 6-hour bidding block, as the timeframe between the BGC and the delivery interval is reduced for all Trading Intervals within a block. There is also the potential for efficiency gains to be made with an amendment to the Market Rules to remove the requirement for Synergy to bid in 6-hour blocks, and to move to a rolling gate closure. This will ensure a 7 MW increase in forecast accuracy for all Trading Intervals, and not just the first Trading Interval in the block.

The Rule Change Panel also notes that AEMO indicated that it did not foresee any operational challenges associated with moving to a rolling gate closure for Synergy. However, other Market Participants will be affected through a possible need to review Synergy's position more frequently.

Nevertheless, the Rule Change Panel considers that the increased requirement to review the market will be a likely outcome of the impending market reforms under the ETS and that the move to a rolling gate closure will reduce the asymmetry in access to accurate information for making trading decisions between IPPs and Synergy and increase competition.

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36 Market Participants were referring to the market arrangements that were implemented in 2012.

Moreover, in being able to respond more flexibly to the changing market conditions, Synergy will provide more cost reflective pricing signals to the market.

The Rule Change Panel's draft decision is therefore to move Synergy's gate closure for the Balancing Market to a rolling gate closure of 150 minutes, allowing Synergy to update its Balancing Submissions more often, to address changes in market conditions.

6.2.2 The LFAS Gate Closure

6.2.2.1 Forecast Accuracy

The same approach to analysis of forecasting error that was employed to assess increases in forecasting accuracy due to a reduction in the BGC was employed to assess increases in forecasting accuracy due to movement of the LFAS Gate Closure closer to real time (see section 6.1.3.2).

The results again showed that there were statistically significant increases in accuracy closer to real time in LSG forecasts. The median differences between absolute errors in LSG Forecasts were:

- 7.3 MW for delivery in the first Trading Interval in the LFAS Horizon for the comparison of the forecast for the current LFAS Gate Closure (i.e. 300 minutes) to the proposed 180 minute gate closure option (i.e. two hours ahead of a 60-minute BGC); and
- 4.7 MW for delivery in the first Trading Interval in the LFAS Horizon for the comparison of the forecast for the current LFAS Gate Closure (i.e. 300 minutes), and the forecast for the proposed 210 minute gate closure option (i.e. two hours ahead of a 90-minute BGC).

Appendix C provides further discussion of the results of the statistical analysis, including charts illustrating the results.

6.2.2.2 Should Synergy Have the Same LFAS Gate Closure as IPPs?

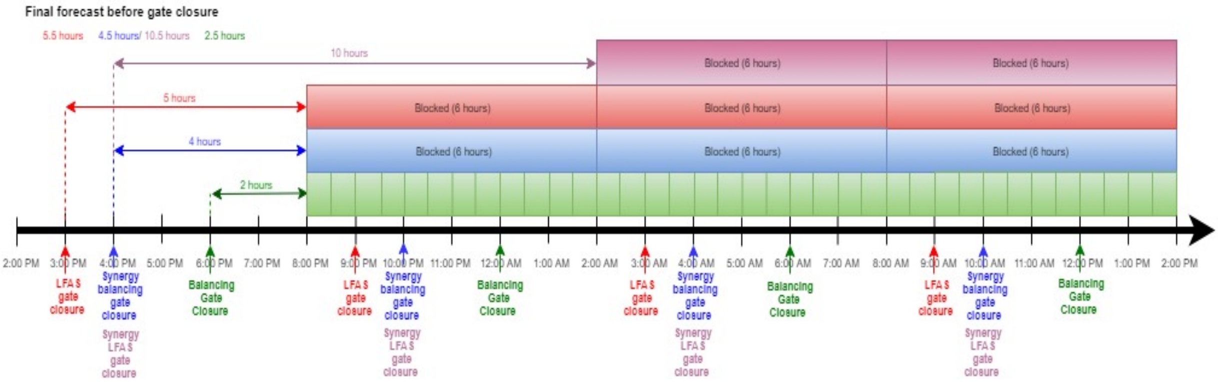
The Rule Change Panel notes that Synergy currently uses the same LFAS Gate Closure as IPPs. This is different to the way that Synergy's LFAS Gate Closure is currently specified in the Market Rules, in which:

- clause 7B.2.3 requires that Synergy must submit a LFAS Submission to AEMO for all Trading Intervals in the Balancing Horizon for which it has not already made an LFAS Submission, immediately before 1:00 PM;
- clause 7B.2.4(aA) allows Synergy to submit an updated LFAS Submission for its Balancing Portfolio for one or more Trading Intervals in the Balancing Horizon for which LFAS Gate Closure has not occurred; and it can do this at the time it makes an updated Balancing Submission under clause 7A.2.9(d);[37] and
- clause 7B.2.9 specifies that the subsequent LFAS submission overrides the earlier LFAS Submission for the relevant Trading Interval.

Figure 2 illustrates the current LFAS Gate Closure arrangements.

[37] That is, immediately before 1:00 PM or within one hour after LFAS Gate Closure, for any Trading Interval in the Balancing Horizon for which BGC is more than two hours in the future.

Figure 2: Current LFAS Gate Closure Arrangements



The Rule Change Panel notes that, despite the market not currently operating in this way, Alinta and ERM expressed a preference in submissions following the 6 September 2019 workshop for the market to operate as specified in the Market Rules. However, AEMO's preference was for Synergy and IPPs to continue to use the same LFAS Gate Closure and no Rule Participants have raised concerns with the Rule Change Panel regarding this arrangement.

As noted above, the Rule Change Panel agrees with AEMO that market efficiency will be improved when all Market Participants are able to make operational decisions with the most accurate available information. The Rule Change Panel therefore can see no reason why it is necessary for Synergy and IPPs to have different LFAS Gate Closures.

The Rule Change Panel's draft decision is therefore to align the IPP and Synergy LFAS Gate Closures, which will also align the requirements in the Market Rules with current practice in the LFAS Market, ensuring clarity for Market Participants and reducing the risk of non-compliance.

6.2.2.3 What Time Difference is needed between the LFAS Gate Closure and Synergy's Gate Closure for the Balancing Market?

The Rule Change Panel considers that a reduced LFAS Gate Closure will give providers of LFAS access to more accurate forecasts closer to real time to bid into the LFAS market. The Rule Change Panel therefore agrees with Kleenheat[38] that reducing the timeframe between LFAS Gate Closure and other Market Participants' gate closures (including Synergy's) as much as possible will provide more accurate information to base Price-Quantity Pairs on in LFAS and Balancing Portfolio submissions, leading to increased efficiency, lower risks and better price signals.

In relation to this, the Rule Change Panel notes that both Synergy and Alinta considered that a minimum 60-minute lag is required between LFAS Gate Closure and BGC to allow participants sufficient time to incorporate LFAS clearing volumes into their Balancing Submissions. To allow for this, the LFAS Gate Closure must be at least an hour ahead of Synergy's gate closure for the Balancing Market. As noted above, Market Participants will then need at least an hour between Synergy's gate closure for the Balancing Market and the BGC to review prices and internal positions, and potentially submit variation Balancing Submissions.

The Rule Change Panel notes that, as with the suggested amendments to Synergy's gate closure for the Balancing Market, AEMO has noted that it does not foresee any additional

38 See Kleenheat's submission following the 6 September 2019 workshop, Appendix B.

operational challenges to shortening the LFAS Gate Closure, as long as the gate closures occur in the same order as they currently occur.

The Rule Change Panel's draft decision is therefore to set the LFAS Gate Closure 210 minutes ahead of the delivery interval, which is an hour ahead of Synergy's gate closure for the Balancing Market (i.e. 150 minutes ahead of the delivery interval), and two hours ahead of the BGC (i.e. 90 minutes ahead of the delivery interval).

6.2.2.4 LFAS Gate Closure Block Bidding Arrangements

The Rule Change Panel considers that a reduced LFAS horizon will give providers of LFAS access to more accurate forecasts closer to real time. However, the Rule Change Panel acknowledges Market Participants preference for block bidding in the LFAS Market and, in particular, Bluewaters, Alinta's and Synergy's concerns regarding the implications of a rolling LFAS Gate Closure. These included increased trading requirements and the need to employ an additional trader to monitor outcomes in the LFAS Market due to:

- the uncertainty in the market, as there are no guarantees on who will be cleared and how much will be cleared in the LFAS Market; and
- the need to make a second Balancing Submission to reflect LFAS Enablement (ensuring that there is sufficient LFAS at the cap and floor pricing) after being cleared in the LFAS Market.

Otherwise, Market Participants may risk inefficient or non-compliant outcomes if they do not realise that they have cleared in the LFAS Market and reposition themselves accordingly in the Balancing Market, leading to penalties.

However, the Rule Change Panel notes that Market Participants did not have any concerns about moving the block structure to four hours instead of six hours, which will remove the errors in forecast accuracy that would occur in the final two hours of the LFAS bidding block. The Rule Change Panel's draft decision is therefore to reduce the LFAS bidding blocks to four hours.

6.2.3 Other Options for Enhancing Information Used in Trading Decisions

Three options were presented to the MAC on 11 February 2020 for enhancing the information used in trading decisions, including:

1. increasing the frequency of the BMO calculation from half-hourly to every ten-minutes for the whole Balancing Horizon, which AEMO assessed would cost $20,000 and take approximately four months to implement;
2. calculation of the Forecast BMO every ten minutes but only for the Trading Interval for which gate closure is about to occur, which AEMO assessed would cost $90,000 and take approximately three months to complete; and
3. publication of a 5-minute balancing load forecast in a new report, which AEMO assessed would cost $20,000 and take approximately one month to complete.

Feedback from the MAC on the three options was mixed. Two Market Generators considered that the proposal to recalculate the Forecast BMO every 10 minutes for every interval in the balancing horizon would not provide benefits proportional to the additional cost, whilst another considered that this option could provide up to date information to inform commitment levels for LFAS.

One Market Generator considered that an updated Forecast BMO every 10-minutes but just for the next Trading Interval would be useful, as it would allow generators to bid more accurately, and would be more cost-efficient compared to the first option. Others considered there was little quantifiable benefit to be gained from this option.

One respondent supported the proposals for an updated Forecast BMO every 10-minutes, but just for the next Trading Interval, and publication of the 5-minute balancing load forecast in a new report, due to the indirect benefits from market efficiency.

The Rule Change Panel notes that, there was some consensus from the MAC that the benefits from the first two options were not proportional to the costs, or there was little quantifiable benefit to be gained from the options. Additionally, while there was some support for the third option, this support was not provided by a Market Generator that might use the information to inform its bidding.

Moreover, only one Market Generator supported the first option for the additional information that it might provide about the LFAS market. The Rule Change Panel notes that there are few Market Participants that currently provide LFAS. Similarly, only one Market Generator supported the second option and this generator updates its Balancing Submissions more frequently than other generators.

The Rule Change Panel does not consider that it is cost effective to implement a Rule Change to accommodate the behaviour of only one or two participants in the market. The Rule Change Panel's draft decision is therefore not to amend the Market Rules to implement any of the three proposed options for enhancing information used in trading decisions.

6.3 Amendments to the Proposed Amending Rules

Following the first submission period, the Rule Change Panel has made some additional changes to the proposed Amending Rules. The additional changes are shown in detail in Section 7 of this report and a summary is provided below.

The Rule Change Panel proposes to amend:

- clause 7A.1.16 to implement a 90-minute BGC and to facilitate the transition to this new BGC at the commencement date, because Synergy's gate closure for the Balancing Market and the LFAS Gate Closure are defined in relation to the BGC;
- clause 7A.1.17 to remove AEMO's ability to change the BGC, as outlined in section 6.1.9, from the commencement date;
- clause 7A.2.6 to reflect the deletion of clause 7A.2.9(e);
- clause 7A.2.9(d) to reduce Synergy's gate closure for the Balancing Market from two hours before BGC to one hour before BGC; and to remove clause 7A.2.9(e) to remove the restriction on Synergy to bid in blocks in the Balancing Market and allow for a rolling gate closure;
- clause 7A.2.12 to reflect deletion of clause 7A.2.9(e), to make direct reference to clause 7A.2.9(d) and to remove reference to it as the applicable clause;
- clause 7A.3.5 and 7B.2.4 to align Synergy's LFAS Gate Closure with the LFAS Gate Closure for other Market Participants;
- clause 7A.2A.4(b)(i)(2) to reflect the changes to clause 7A.2.9(d);
- the definition of 'Balancing Gate Closure' to reflect the changes to clauses 7A.1.16 and 7A.1.17;

- the definition of 'LFAS Gate Closure' to shorten the LFAS Gate Closure from three to two hours before BGC and reflect shortening the size of the blocks from six hours to four hours; and
- the definition of 'LFAS Horizon' to shorten the LFAS blocks from six hours to four hours and reflect changes to the LFAS Gate Closure.

6.4 Wholesale Market Objectives

The Rule Change Panel considers that the proposed amendments to the BGC, Synergy's gate closure for the Balancing Market and the LFAS Gate Closure, will:

- allow Market Participants, including Synergy, to delay making trading decisions in both the Balancing and LFAS markets until closer to real time, when more accurate forecasts of LSG for each Trading Interval are available; and
- allow Synergy to provide more accurate pricing signals to the market.

The Rule Change Panel considers that this will reduce risk and allow Market Participants to respond to changing market conditions, promoting economic efficiency and minimising the long-term cost of electricity supplied to consumers (Wholesale Market Objectives (a) and (d)).

Furthermore, the Rule Change Panel considers that the proposed amendments to:

- Synergy's gate closure for the Balancing Market will reduce the asymmetry in access to accurate information for making trading decisions between IPPs and Synergy in the Balancing Market, increasing competition (Wholesale Market Objective (b)); and
- the LFAS Gate Closure will also align the requirements in the Market Rules with practice in the LFAS Market, ensuring clarity for Market Participants and reducing the risk of non-compliance (Wholesale Market Objective (d)).

The Rule Change Panel notes that the proposed amendments to the BGC, as modified in this Draft Rule Change Report, are consistent with changes in market design to accommodate an increasing penetration of renewable technologies observed in other jurisdictions (Wholesale Market Objective (c)).[39]

The Rule Change Panel therefore considers that the proposed amendments to the Market Rules, as modified in this Draft Rule Change Report, will better achieve Wholesale Market Objectives (a), (b), (c) and (d); and are consistent with Wholesale Market Objective (e).

6.5 Protected Provisions, Reviewable Decisions and Civil Penalties

The proposed Amending Rules do not amend any Protected Provisions or Reviewable Decisions. However, it is proposed to amend clause 7A.2.9(d) and to remove clause 7A.2.9(e). Clause 7A.2.9 is a civil penalty provision.

Clause 7A.2.9 outlines the requirements for Synergy's Balancing Submissions. The amendment to sub-clause 7A.2.9(d) clarifies that Synergy's gate closure for the Balancing Market is one hour ahead of BGC and removal of clause 7A.2.9(e) removes the requirement for block bidding by Synergy.

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39 For example, see IEA, Electricity market design and Renewable Energy (**RE**) Deployment (RES-E-MARKETS), September 2016; KPMG, Electricity Market Design Principles – identifying long-term market design principles to support a sustainable energy future for Australia April 2018.

The Rule Change Panel considers that the proposed amendments to clause 7A.2.9:

- should not affect the classification of this clause as a civil penalty provision; and
- do not alter the intent of the clause and so no amendment to the current civil penalty is required.

The Rule Change Panel will liaise with EPWA on the proposed changes to the civil penalty provision.

The Rule Change Panel does not consider that any of the other proposed new Amending Rules should be reviewable decisions or civil penalty provisions.

6.6 Practicality and Cost of Implementation

6.6.1 Cost

6.6.1.1 First Period Submissions

AEMO's initial assessment of the cost and practicality of implementing the changes in this Rule Change Proposal only considered a change in the BGC on AEMO's systems and processes. While AEMO provided suggestions for complementary changes that may assist the transition to a gate closure of less than 90 minutes, it had not yet analysed the potential costs of these changes due to the range of available implementation options.

AEMO considered that it would need to make the following changes to its Wholesale Electricity Market Systems (**WEMS**) to accommodate a later BGC of 30 minutes or more:

- configuration changes to the BGC parameter, as the BGC is a configurable field in the WEMS;
- changes to systems that support monitoring and compliance processes; and
- amendments to the automated test suite.

However, a BGC of less than 30 minutes would require more substantial changes to AEMO's systems, such as the timing of the calculations for the BMO processes, and it may even need to invest in improving the efficiency of the calculation of the BMO.

Similarly, AEMO anticipated that only minor changes would be required in the IT systems that support power system operation. AEMO noted that the System Operating Command and Control Centre User Interface (**SOCCUI**) is currently able to accommodate gate closure periods down to 30 minutes.[40] However, a gate closure period of less than 30 minutes would require changes to processing cycles, leading to more substantial system change requirements.

AEMO considered that minor changes to Market Procedures, internal procedures, compliance monitoring processes for gate closure violations, and documentation and information published by AEMO would be required to accommodate changes to BGC, although the scope of the required changes had not yet been compiled.

Alinta noted that the specific costs associated with reducing the gate closure will depend on the solution adopted but identified the possible costs as:

- AEMO (including System Management) system, staff and procedure costs; and

40 The SOCCUI is AEMO's interface for dispatch and system control of the SWIS.

- Market Participant's IT system, staff and procedure costs, as well as any software changes to implement flexible ramping (if required).

Alinta considered that it would be in a better position to quantify any costs it expects to incur once the Rule Change Panel releases its draft decision.

AEMO and Alinta both considered that shortening the gate closure would reduce the current delay when a generating unit returns to service following maintenance, with low cost generation displacing higher cost generation, and would reduce the Balancing Price. AEMO noted the PUO's estimate of a recurring benefit of $300,000 per annum (see section 5.2.3) and considered that a shift to a 90-minute BGC could realise approximately one-third of this benefit.

Synergy disagreed with the PUO's estimate, noting that a Facility operator will know well in advance of two hours when its Facility will be able to return from a Forced Outage. However, the Rule Change Panel notes that it is the BGC that constrains the ability of a Facility to return to service, rather than whether a participant has knowledge more than two hours ahead of whether it can return to service. If the BGC is reduced, Market Participants can return to service closer to the delivery interval.

Community Electricity noted that the question of the costs involved in implementing the change is not applicable to it as it is a pure retailer.

Perth Energy considered that, as participants already have an obligation to update their Balancing Submissions after BGC under some circumstances, Perth Energy will not incur any additional costs associated with the proposed changes.

Synergy noted that the changes would require Synergy to make minimal changes to its IT systems. However, Synergy considered that this Rule Change Proposal will cause a significant wealth transfer from Synergy to other Market Participants with no other benefit that is consistent with the Wholesale Market Objectives. However, this assessment appears to be based on a shortening of the BGC for IPPs but no change to Synergy's gate closure.

6.6.1.2 6 September 2019 MAC Workshop

In its advice to the Panel following the 6 September MAC workshop, Alinta noted that it is likely to be able to implement linear ramping for a 30-minute Trading Interval for its Scheduled Generators but it is likely to cost in the order of $200,000 per unit, as it requires both control system and governor changes.

6.6.1.3 18 October 2019 MAC Workshop

In the 18 October 2019 MAC meeting, Bluewaters questioned whether most of AEMO's costs associated with the 90-minute BGC would already exist in the 120-minute BGC. AEMO confirmed that the difference between the 90- and 120-minute BGCs would be zero. Mr Arias considered that, on that basis, that the starting point for the Rule Change Proposal was a 90-minute BGC.

6.6.1.4 AEMO's Automated Linear Ramping Solution

AEMO provided feedback to the Rule Change Panel on 30 January 2020 in which it noted that implementation of automated linear ramping would not be without moderate costs and that there would be ongoing constraint payments. AEMO's cost estimate for implementing automatic linear ramping was $200,000, which covered changes to the RTDE and the user interface (SOCCUI).

AEMO did not consider its estimate to be expensive or technically challenging. However, AEMO acknowledged that, without Market Rule changes to the TES calculations, there were constraint payment cost implications from the application of linear ramping, estimated to be in the range of $1 million to $3 million per annum, which AEMO described as being 'moderate.'

AEMO noted that its estimate for the cost of implementation was a high-level estimate and reiterated that detailed design for its systems and processes have not yet been determined.

6.6.2 Practicality

6.6.2.1 First Period Submissions

AEMO advised that a shift to a 90-minute BGC could commence in advance of IT system changes, which would take approximately three to six months to implement and schedule into AEMO's IT release plan. AEMO suggested that, in the interim, Market Participants could be instructed to ignore warning messages related to submissions in the period between two hours and 90 minutes before the start of the Trading Interval, although AEMO considered that this would not be ideal.

AEMO further advised that the security controller role was scheduled to be operational in the fourth quarter of 2017. AEMO considered that this would share some of the operational burden on the generation controllers and reduce any risk to system security that could otherwise occur by an increase in the generation controller's workload from a move to a shorter gate closure which may occur due to increased market dynamics.[41] AEMO had not yet analysed the scope or time requirements associated with the complementary changes to dispatch and settlement arrangements.

Alinta noted that if the Rule Change Proposal is accepted as proposed, Alinta would be able to implement the change with limited lead time. However, Alinta considered that if it is required to make software changes to allow for greater flexibility in ramping, Alinta would need sufficient time to implement this solution. Alinta considered that it will be in a better position to identify the time required before implementation once the Rule Change Panel releases its draft decision.

Community Electricity noted that the question of the time required for implementing the change is not applicable to it as it is a pure retailer.

Perth Energy also considered that the question of the time required for implementing the change is not applicable to Perth Energy.

6.6.2.2 AEMO's Automated Linear Ramping Solution

AEMO provided feedback to the Rule Change Panel on 30 January 2020 in which it considered that its linear ramping solution is both practical and feasible to implement, as rule changes are not required for implementation.

6.6.2.3 6 September 2019 MAC Workshop

In discussion regarding AEMO's automated linear ramping solution, Alinta noted that Market Participants may need time to implement control system and governor changes to implement linear ramping, which requires outage planning, outages, testing, commissioning, and finding

41 AEMO advised that the security desk role was in place at the end of 2017. The role provides support to security decisions that need to be made in the control room and therefore does share some of the operational burden and has reduced the risk associated with having a single generation controller.

a supplier. Alinta noted that, there was not enough information about the automated linear ramping process and that Market Participants do not already have an outage plan or an outage scheduled, which would make it difficult to provide a timeframe for implementation.

6.6.3 Assessment of Cost and Practicality

The Rule Change Panel notes AEMO's intention to implement an automated linear ramping process if a change is made to a 60-minute BGC, and that the potential costs associated with implementation of this process supersede AEMO's assessment of the cost implications provided in its first period submission.

This automated linear ramping process will take time to implement and will:

- incur costs on AEMO of approximately $200,000 for implementation of the automated linear ramping process.
- incur costs on some Market Participants of approximately $200,000 per generation unit to make control system and governor changes to allow for flexible ramping; and
- involve constraining the ramp rates of individual IPPs, which will lead to constraint payments of about $1 million to $3 million per annum.

There were also other minor costs associated with administrative and IT system changes identified by both AEMO and Market Participants.

While AEMO considered that its automated linear ramping process is both practical and feasible to implement because it does not require changes to the Market Rules, Alinta noted the difficulties in being able to provide a timeframe for implementation of modifications to its units and, in particular, the need to plan and schedule outages, and source suppliers, which could take some time.

The Rule Change Panel is aware of the short duration until the new market arrangements under the ETS reforms, which are scheduled for progressive implementation from 1 October 2022, and that AEMO's resources are stretched, given the workload involved with these reforms. The Rule Change Panel therefore considers that this should be accounted for in assessment of this proposal and in setting the commencement date for the Amending Rules.

The Rule Change Panel has therefore decided to avoid the costs and timeframe associated with the implementation of AEMO's automated linear ramping process and to move to a 90-minute BGC. AEMO previously indicated that a change to a 90-minute BGC is achievable with low implementation cost and risk. However, AEMO has been unable to confirm this, or to provide cost and time estimates for the changes to Synergy's gate closure for the Balancing Market or to the LFAS Gate Closures, in time for publication of this Draft Rule Change Report.

While the Rule Change Panel has not conducted a formal cost-benefit analysis for this Rule Change Proposal, based on this previous advice from AEMO, the Rule Change Panel is of the view that AEMO's costs to implement the proposed amendments are justified by the likely efficiency benefits resulting from the ability of Market Participants to make trading decisions based on more accurate forecasting information.

7. Amending Rules

The Rule Change Panel proposes to implement the following Amending Rules (~~deleted text~~, added text,). The Amending Rules are presented below in their entirety, marked up against the Market Rules as at 08 April 2020 and the Amending Rules in RC_2018_05 which will commence on 21 July 2020.

…

7A.1.16. With effect on and from the Trading Interval commencing at 8:00 AM on the Balancing Market Commencement Day until the end of the Trading Interval commencing at 7:30 AM on DD.MM.YYYY, AEMO must determine a point in time immediately before the commencement of a Trading Interval for the purpose of setting the Balancing Gate Closure. The point in time must be no shorter than two hours and no longer than six hours before the commencement of a Trading Interval and must be published on the Market Web Site.

~~7A.1.17. AEMO may, from time to time, change the point in time determined under clause 7A.1.16 by publishing the new point in time on the Market Web Site and specifying the date from which the new point in time is to take effect, which shall be no earlier than 2 months from the date of publication.~~

7A.1.17. With effect on and from the Trading Interval commencing at 8:00 AM on DD.MM.YYYY and all Trading intervals thereafter, the Balancing Gate Closure is 90 minutes immediately before the commencement of the Trading Interval.

7A.2. Balancing Submissions

7A.2.1. A Market Participant must at all times ensure that it has made a Balancing Submission in accordance with clause 7A.2.4 for each Trading Interval in the Balancing Horizon for each of its Balancing Facilities.

7A.2.2. A Market Participant may submit a subsequent Balancing Submission in accordance with clause 7A.2.4 in respect of any of its Balancing Facilities, excluding Facilities in the Balancing Portfolio, and:

(a) the Balancing Submission may be for one or more Trading Intervals in the Balancing Horizon; and

(b) the Balancing Submission must be made before Balancing Gate Closure for any Trading Interval in the submission.

7A.2.3. A Market Participant with a Balancing Facility that is:

(a) the subject of an Operating Instruction; or

(b) undergoing a Test that has an approved Test Plan,

must ensure that a Balancing Submission submitted under this section 7A.2 is consistent with the proposed operation of the Balancing Facility for each Trading Interval specified in the Operating Instruction or the Test Plan. The provisions of this clause 7A.2.3 do not apply to the Balancing Portfolio.

7A.2.4. A Balancing Submission must:

(a) be in the manner and form prescribed and published by AEMO;

(b) constitute a declaration by an Authorised Officer;

(c) have Balancing Price-Quantity Pair prices within the Price Caps;

(d) specify, for each Trading Interval covered in the Balancing Submission, whether the Balancing Facility is to use Liquid Fuel or Non-Liquid Fuel;

(e) specify the Ramp Rate Limit or the Portfolio Ramp Rate Limit (as applicable) for each Trading Interval covered in the Balancing Submission; and

(f) specify the available capacity and the unavailable capacity as determined under clause 7A.2.4A, 7A.2.4B or 7A.2.4C (as applicable) for each Trading Interval covered in the Balancing Submission.

…

7A.2.6. A subsequent Balancing Submission made under clauses 7A.2.2, 7A.2.9(d), ~~7A.2.9(e),~~ 7A.2.9(f), 7A.2.9B, 7A.2.9C, 7A.2.10 or 7A.3.5 in respect of the same Balancing Facility covering the same Trading Interval as an earlier Balancing Submission, overrides the earlier Balancing Submission for, and has effect in relation to, that Trading Interval.

…

7A.2.9. Synergy, in relation to the Balancing Portfolio:

(a) must, subject to clauses 7A.2.9(d) to 7A.2.9(f), ensure that for each Trading Interval in the Balancing Horizon the most recently submitted Balancing Submission in respect of that Trading Interval accurately reflects:

i. all information reasonably available to Synergy, including Balancing Forecasts published by AEMO and the latest information available to Synergy in relation to any Forced Outage for a Facility in the Balancing Portfolio;

ii. subject to clause 7A.2.9A(b), Synergy's reasonable expectation of the capability of its Balancing Portfolio to be dispatched in the Balancing Market for that Trading Interval; and

iii. the price at which Synergy intends to have the Balancing Portfolio participate in the Balancing Market;

(b) must indicate in a manner and form prescribed by AEMO:

i. which of the Balancing Price-Quantity Pairs that it has priced at the Minimum STEM Price are for Facilities that are to provide LFAS;

ii. which Facilities are likely to provide LFAS; and

iii. for each completed Trading Interval, which Facilities actually provided the LFAS in the Trading Interval;

(c) must:

i. ensure that quantities in the Balancing Price-Quantity Pairs in its Balancing Submissions that are required for the provision of Ancillary Services, other than LFAS, are priced at the Price Caps;

ii. advise AEMO in a manner and form prescribed by AEMO, the Facilities which are likely to provide the quantities specified in clause 7A.2.9(c)(i); and

iii. for each completed Trading Interval, advise AEMO which Facilities actually provided the Ancillary Services referred to in clause 7A.2.9(c)(i) in the Trading Interval;

(d) may submit a new, updated Balancing Submission in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure is more than ~~two~~ one hour~~s~~ in the future;~~:~~

~~i. by submitting its updated Balancing Submission to AEMO immediately before 1:00 PM; or~~

~~ii. otherwise by submitting its updated Balancing Submission to AEMO within one hour after LFAS Gate Closure;~~

(e) ~~may submit a new, updated Balancing Submission in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure is more than two hours in the future if a Facility in the Balancing Portfolio has experienced a Forced Outage since the last Balancing Submission;~~[Blank]

(f) may after the time specified in clause 7A.2.9(d), submit a new, updated Balancing Submission to reflect the impact of a Forced Outage which Synergy expects will cause a Facility to run on Liquid Fuel, where the Facility would not have run on Liquid Fuel but for the Forced Outage, in order to meet Synergy's Balancing Market obligations in relation to the Balancing Portfolio under this Chapter 7A; and

(g) must, as soon as it becomes aware that:

i. either:

1. a Facility in the Balancing Portfolio has experienced a Forced Outage; or

2. System Management has approved a request for Opportunistic Maintenance for a Facility in the Balancing Portfolio; and

ii. the outage will reduce the available capacity of the Balancing Portfolio in a Trading Interval in the Balancing Horizon from the quantity reported as available in the current Balancing Submission for that Trading Interval; and

iii. there is a credible risk that representation of the relevant capacity as available in the Balancing Submission might, in the circumstances:

1. affect any expected EOI Quantity provided to another Market Participant for the Trading Interval under clause 7A.3.1(c); or

2. cause System Management to dispatch Balancing Facilities Out of Merit under clauses 7.6.1C(b) or 7.6.1C(c),

submit a new, updated Balancing Submission for the Trading Interval to:

iv. make any relevant Scheduled Generator capacity subject to the outage unavailable; and

v. unless otherwise permitted under clauses 7A.2.9(d) to 7A.2.9(f), remove or reduce the quantity of the highest price Balancing Price-Quantity Pair or Balancing Price-Quantity Pairs (excluding any Balancing Price-Quantity Pairs that are required to be offered at the Price Caps under clause 7A.2.9(c)) to remove the capacity subject to the outage from its Balancing Price-Quantity Pairs.

…

7A.2.12. Where Synergy has submitted an updated Balancing Submission for the Balancing Portfolio in accordance with clause~~s 7A.2.9(e) or~~ 7A.2.9(f) because of a Forced Outage of one of the Facilities in the Balancing Portfolio after the time specified in ~~the applicable~~ clause 7A.2.9(d) it must, as soon as reasonably practicable, provide AEMO with written details of:

(a) the nature of the Forced Outage;

(b) when the Forced Outage occurred;

(c) the duration of the Forced Outage; and

(d) information substantiating the commercial impact, if any, of the Forced Outage.

…

7A.3.5. A Market Participant~~, other than Synergy in respect of the Balancing Portfolio,~~ must, within 60 minutes after LFAS Gate Closure for an LFAS Horizon, for each Trading Interval in that LFAS Horizon, use its best endeavours to make a new Balancing Submission for each of its LFAS Facilities in the LFAS Enablement Schedules for that Trading Interval, which must fulfil the following conditions:

(a) the total quantity in Balancing Price-Quantity Pairs priced at the Alternative Maximum STEM Price is at least the Upwards LFAS Enablement for the Facility; and

(b) the total quantity in Balancing Price-Quantity Pairs priced at the Minimum STEM Price is at least the quantity of capacity for the Facility specified in Appendix 1(b)(xiii) plus the Downwards LFAS Enablement for the Facility.

…

7A.2A.1. Subject to clauses 7A.2A.3 and 7A.2A.4, a Market Participant (other than Synergy in respect of the Balancing Portfolio) must, as soon as practicable after each Trading Interval, for each of its Balancing Facilities that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage that relates to any capacity for which the Market Participant holds Capacity Credits that:

(a) was declared unavailable in the Facility's Balancing Submission for that Trading Interval; and

(b) was not subject to an approved Planned Outage, Consequential Outage or Commissioning Test Plan in that Trading Interval,

unless the relevant capacity was declared unavailable in the Facility's Balancing Submission because the Market Participant reasonably expected that its Reserve Capacity Obligations for the Trading Interval would be reduced because the maximum site temperature for the applicable Trading Day would exceed 41 degrees Celsius.

7A.2A.2. Subject to clauses 7A.2A.3 and 7A.2A.4, Synergy must, as soon as practicable after each Trading Interval, for each Facility in the Balancing Portfolio that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage that relates to any capacity for which Synergy holds Capacity Credits that:

(a) was declared unavailable in the Balancing Portfolio's Balancing Submission for that Trading Interval; and

(b) was not subject to an approved Planned Outage, Consequential Outage or Commissioning Test Plan in that Trading Interval,

unless the relevant capacity was declared unavailable in the Balancing Portfolio's Balancing Submission because Synergy reasonably expected that its Reserve Capacity Obligations for the Trading Interval would be reduced because the maximum site temperature for the applicable Trading Day would exceed 41 degrees Celsius.

…

7A.2A.4. Clauses 7A.2A.1 and 7A.2A.2 do not apply in respect of a Trading Interval if:

(a) the relevant capacity was previously subject to an approved Consequential Outage or Commissioning Test Plan for the Trading Interval; and

(b) System Management notified the Market Participant that the capacity was no longer subject to the Consequential Outage or Commissioning Test Plan for the Trading Interval:

i. less than 30 minutes before:

1. Balancing Gate Closure for the Trading Interval, for a Facility that is not in the Balancing Portfolio; or

2. the ~~latest~~ time specified in clause 7A.2.9(d) for the Trading Interval, for a Facility in the Balancing Portfolio; or

ii. at a time when the Facility was not synchronised and could not be synchronised by the start of the Trading Interval given the Facility's relevant Equipment Limits.

…

7B.2. LFAS Submissions

7B.2.1. A Market Participant may submit an LFAS Submission in respect of any of its LFAS Facilities, other than the Balancing Portfolio:

(a) in accordance with clause 7B.2.7;

(b) for any or all Trading Intervals in the Balancing Horizon; and

(c) before LFAS Gate Closure for those Trading Intervals.

7B.2.2. A Market Participant may submit an updated LFAS Submission in respect of any of its LFAS Facilities other than the Balancing Portfolio:

(a) in accordance with clause 7B.2.7;

(b) for one or more Trading Intervals in the Balancing Horizon; and

(c) before LFAS Gate Closure for those Trading Intervals.

7B.2.3. Synergy must, immediately before 1:00 PM, submit an LFAS Submission, for all Trading Intervals in the Balancing Horizon for which it has not already made an LFAS Submission, by submitting it to AEMO in accordance with clauses 7B.2.5, 7B.2.6 and 7B.2.7.

7B.2.4. Subject to clause 7B.2.5, Synergy may submit an updated LFAS Submission in respect of the Balancing Portfolio:

(a) in accordance with clauses 7B.2.6 and 7B.2.7; and

(aA) for one or more Trading Intervals in the Balancing Horizon for which LFAS Gate Closure has not occurred.~~; and~~

~~(b) at the time it makes an updated Balancing Submission under clause 7A.2.9(d).~~

…

11. Glossary

...

Balancing Gate Closure: For a Trading Interval means the point in time immediately before the commencement of the Trading Interval determined ~~by AEMO under clause 7A.1.16 or 7A.1.17, as applicable~~ in accordance with clauses 7A.1.16 or 7A.1.17 as applicable.

…

LFAS Gate Closure: Means, for the ~~12~~ eight Trading Intervals in an LFAS Horizon, the point in time which is ~~3~~ two hours immediately before the Balancing Gate Closure for the first of those Trading Intervals.

LFAS Horizon: Means a ~~6~~ four hour period commencing at 8:00 AM, 12:00 PM, 4:00 PM~~2:00 PM~~, 8:00 PM, 12:00 AM or 4:00 AM ~~2:00 AM~~, as applicable.

…

Appendix A. Responses to Submissions Received in the First Submission Period

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
AEMO's Advice on Gate Closure Options			
1	AEMO	AEMO advised that the current hybrid design of the Balancing Market, with System Management retaining responsibility for scheduling and dispatching generation Facilities within the Synergy Balancing Portfolio, constrains the extent to which the BGC can be shifted later. AEMO noted that this constraint was acknowledged (albeit superficially) in MAC discussions in 2010 preceding the design and development of the Balancing Market, and the chosen market design pathway was to "push the [then] current hybrid model as far as it can go". AEMO considered that compared to more advanced market designs, the hybrid model was acknowledged as providing a reduced opportunity to shorten the gate closure.	The Rule Change Panel agrees with AEMO that the hybrid design of the market constrains the extent to which the BGC can be shifted later and notes that it agrees with Alinta that there is a trade-off between shifting the BGC closer to real time and maintaining system security. See section 6.1.2 for a discussion on the options to reduce the BGC.
2	AEMO	AEMO explained that the WEM differs from other electricity markets as AEMO's generation controllers have an incomplete generation dispatch schedule at the point of BGC, with information only about the dispatch of energy and LFAS from IPP Facilities, which frequently provide less than half of the energy and LFAS Requirements of the WEM in aggregate. After BGC, AEMO's generation controllers must 'fill in the gaps,' analysing the Forecast [BMO] and scheduling the various Balancing Portfolio Facilities to achieve energy dispatch consistent with the BMO. AEMO's generation	The Rule Change Panel notes that Synergy's gate closure for the Balancing Market and Synergy's LFAS Gate Closure occur prior to the IPPs BGC. AEMO's generation controllers should therefore have information about Synergy's LFAS Facilities and the Balancing Portfolio that can be used to inform decisions about dispatch at the point of BGC. The Rule Change Panel acknowledges the process used by controllers to 'fill in the gaps' to achieve energy dispatch consistent with the BMO and that it is a function of System Management to procure adequate Ancillary

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		controllers must also ensure adequate Ancillary Service availability to manage system frequency and maintain Power System Security (noting that the Balancing Portfolio provides the majority of the LFAS, Spinning Reserve Service and Load Rejection Reserve Service requirements). In some circumstances, the scheduling of the Balancing Portfolio requires movement of Synergy Facilities in advance of the Trading Interval to ensure sufficient capability for the Balancing Portfolio as required to achieve BMO requirements.	Services and ensure that the SWIS operates in a secure and reliable manner (see section 6.1.7.2, under 'Increasing Need for LFAS). The Rule Change Panel further acknowledges that one of the options employed by System Management to address the aggregate ramp issue is to dispatch Synergy's Facilities ahead of the Trading Interval to ensure that the Balancing Portfolio has the ramp capability necessary to offset the aggregate ramp of IPPs.
3	AEMO	AEMO noted that where multiple Facilities are ramping in the same direction from the start of a Trading Interval, this has the implication of creating an aggregate ramp movement that may exceed the underlying movement in demand in the early minutes of the Trading Interval. The Balancing Market design accounts for total upward and downward ramping movements in solving the end-of-interval energy balance but does not consider ramping misalignment that can affect the energy balance within the Trading Interval. By default, the implication of this is that any ramping mismatch within the Trading Interval is assumed to be absorbed by LFAS.	The Rule Change Panel notes AEMO's description and explanation of the aggregate ramp issue. However, the Rule Change Panel does not agree that: • the ramping misalignments within the Trading Interval that can affect the energy balance within the Trading Interval are not contemplated under the Market Rules; or • the absorption of the ramping mismatch by LFAS is an implication or assumption, rather than a requirement. See section 6.1.4.2 of this report.
4	AEMO	The standard for Spinning Reserve Service in clause 3.10.2 is set at a level to cover only 70 per cent of the output of the generating unit with the highest output at that time and must include LFAS capacity. Consequently, where LFAS upward-moving capability is	The Rule Change Panel notes that the overlap between Spinning Reserve Service and LFAS can reduce the availability of these services. However, the Rule Change Panel considers that the standard for Spinning Reserve does not limit the LFAS Requirement and that it is a

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		absorbing ramping mismatches within a Trading Interval, this can lead to a reduction in the available Spinning Reserve Service capability for short periods, leaving the SWIS vulnerable to a contingency event that occurs during the ramping mismatch.	function of System Management to procure adequate Ancillary Services to ensure that the SWIS operates in a secure and reliable manner. See sections 6.1.4.2 and 6.1.7.2 of this report.
5	AEMO	AEMO analysed the Dispatch Instruction data for the 2016 calendar year and found that: • The aggregate start of interval ramping of IPP generators exceeded 10 MW per minute in 670 Trading Intervals (nearly four per cent of Trading Intervals, or two per day) and exceeded 15 MW/minute in 193 Trading Intervals (one per cent of the year, or once every second day). • IPP generators frequently finished their ramping in the early minutes of the interval. Of the 670 Trading Intervals where the aggregate ramping exceeded 10 MW per minute, the maximum ramp duration was: o less than 5 minutes in 180 of these Trading Intervals (27 per cent); o less than 10 minutes in 492 of these Trading Intervals (73 per cent); and o less than 15 minutes in 585 of these Trading Intervals (87 per cent). AEMO noted that similar proportions were evident for the Trading Intervals where the aggregate ramping exceeded 15 MW per minute.	The Rule Change Panel notes AEMO's findings regarding the aggregate ramping issue in 2016, and in particular, that: • the aggregate ramping of IPPs exceeded Synergy's ramp rate in only 193 Trading Intervals in this period; and • the maximum ramp duration was less than ten minutes in 73% of these Trading Intervals (although AEMO did not provide the actual percentages for the 193 Trading Intervals in which the aggregate ramping of IPPs exceeded Synergy's ramp rate). The Rule Change Panel notes that AEMO's new method for identifying when an aggregate ramp issue occurs identified a much higher incidence (i.e. 7%) than the incidence of the aggregate ramp issue in 2016. See section 6.1.6 for discussion of AEMO's approach to determining when linear ramping is required and to identifying the incidence of the aggregate ramp issue.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
6	AEMO	AEMO advised that AEMO's generation controllers have an incomplete dispatch schedule at the point of BGC and are required to plan and execute the dispatch of the Facilities within the Balancing Portfolio during the two hours before the start of the Trading Interval. During this time, controller is seeking to satisfy multiple objectives: • dispatch of energy according to the BMO (including accommodation of the aggregate ramping requirements of IPP generating units), the Synergy dispatch guidelines (provided under clause 7.6A.2(a)), and the obligation to employ reasonable endeavours to minimise changes to the Synergy Dispatch Plan (under clause 7.6.2A), noting that the Balancing Portfolio provides roughly half of the annual energy requirements of the WEM; • dispatch of LFAS according to the LFAS Merit Order and the Synergy dispatch guidelines (provided under clause 7.6A.2(a)), noting that the Balancing Portfolio provides more than half (and sometimes all) of the WEM's LFAS Requirement; • availability of adequate Spinning Reserve Service and Load Rejection Reserve Service to satisfy the requirements for these services in clause 3.10 of the WEM Rules; and • maintenance of Power System Security.	The Rule Change Panel agrees with AEMO's explanation of its functions and requirements under the Market Rules.
7	AEMO	AEMO explained that during the period between receipt of the final BMO (a few minutes after the BGC) and the start of the Trading Interval, where a forecast change of	The Rule Change Panel notes AEMO's explanation of its processes and has considered the timeframes for each process in its assessment of options for reducing the

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		at least 50 MW is required in Balancing Portfolio generation (i.e. in about 40% of Trading Intervals), the controller: • Takes a few minutes to perform an initial assessment of the current operating levels and ramping capability of the Facilities within the Balancing Portfolio, comparing these with the BMO and system security assessments to determine whether a detailed assessment will be required; • Takes approximately 15 to 20 minutes to perform a detailed assessment to plan material changes to the Balancing Portfolio dispatch before the start of the Trading Interval, such as starting or stopping a generating unit or a coal mill, in order to achieve the required energy movement, aggregate ramp rate and/or preserve or restore system security. • Issues the relevant instructions to Synergy power station operators to give effect to the chosen Balancing Portfolio Dispatch Plan, with longer lead time actions, such as starting or stopping coal mills and slow ramping of coal units, collectively taking 45 to 60 minutes, and the start-up of open cycle gas turbines taking up to 15 minutes. AEMO considered that in total, the time requirement for these steps can exceed 80 minutes in circumstances where larger movements of the Balancing Portfolio Facilities are required in advance of the Trading Interval and, in extreme cases, can exceed 90 minutes.	BGC. On the basis of this assessment, the Rule Change Panel agrees with AEMO that a move to a 30-minute BGC is not feasible under the current market design (see section 6.1.2 of this report). The Rule Change Panel notes AEMO's observation that the time requirement for these steps can exceed 80 minutes in circumstances where larger movements of the Facilities in the Balancing Portfolio are required in advance of the Trading Interval and, in extreme cases, can exceed 90 minutes. However, in 2017 AEMO indicated that this occurred in only 1% of Trading Intervals in 2016 and, using its new method for assessing the requirement for linear ramping, in 7% of Trading Intervals in the 2018/19 period (see section 6.1.6 for a discussion of AEMO's approach to determining the incidence of the aggregate ramp issue). See section 6.1.4 for discussion of the options that AEMO has available to offset the aggregate ramp of IPPs.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		AEMO further noted that, in parallel to the steps described above, the generation controller routinely undertakes system security assessments when significant changes in system dynamics occur, to identify any potential contingency violations and assess alternative generation scenarios. According to AEMO, this takes approximately 25 minutes, after which any contingencies identified may require a detailed assessment of the ability of the system to accommodate changes in dispatch.	
8	AEMO	AEMO considered that a reduction of the gate closure to 90 minutes is likely to be achievable without any additional changes to the design of the Balancing Market, though it may result in some increases to constrained on/off compensation in situations where required movements of the Balancing Portfolio are large and preparatory steps must be taken in advance of the Trading Interval. AEMO advised, however, that a reduction to a 60-minute BGC would require some complementary changes to dispatch and settlement arrangements to reduce the scope of those preparatory steps (and hence the time required to execute them). AEMO advised that a shift to 30-minute Balancing Gate Closure is infeasible with the current hybrid design of the Balancing Market, and in the absence of more fundamental reform of the WEM.	The Rule Change Panel notes AEMO's advice in relation to the options for reducing the BGC. The Rule Change Panel agrees with AEMO that a 30-minute BGC is infeasible under the current market design. See section 6.1.2 of this report for a discussion of this topic. Also see: • section 6.1.3.2 for a comparison of the benefits achievable in forecast accuracy under the 60- and 90-minute BGC options; • section 6.1.6 for discussion of AEMO's method for determining when linear ramping is required; and • section 6.1.8 for discussion of AEMO's linear ramping solution.
9	AEMO	AEMO observed that the need to accommodate the aggregate ramping of IPP generators at the start of a	The Rule Change Panel notes the requirements and obligations on AEMO under the Market Rules.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Trading Interval can create challenges for AEMO's generation controllers and require preparatory scheduling of the Balancing Portfolio to balance the ramping without materially eroding Ancillary Service quantities within a Trading Interval.	
Support for and Opposition to the Proposal			
10	AEMO	AEMO noted that it was supportive of a shortened gate closure (or removal of the gate closure) but considered that this could best be achieved as part of the full set of WEM reforms proposed by the PUO.	The Rule Change Panel notes the short duration until the commencement of the new market arrangements under the ETS reforms, which are scheduled for progressive implementation from 1 October 2022. However, the Rule Change Panel also notes AEMO's advice that the implementation costs for a 90-minute BGC will be low and will require limited system changes. AEMO suggested in its first period submission that the Rule Change Panel consider the merit of changes to related market timeframes, particularly the LFAS Gate Closure and the deadlines for Synergy in submitting updated Balancing Portfolio Supply Curves. In out of session consultation, AEMO noted that a change to Synergy's gate closure for the Balancing Market involves a change to a parameter in its IT systems. However, AEMO has not investigated the ease (or difficulty) of reducing the LFAS Gate Closure or bidding block size.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
			Nevertheless, AEMO's submission following the 6 September 2019 workshop indicates that it can see no system security or operational issues associated with: • reducing Synergy's gate closure for the Balancing Market; • a rolling gate closure for Synergy's Balancing Submissions; • reducing the LFAS Gate Closure; and • a rolling gate closure for LFAS Submissions. The Rule Change Panel is awaiting cost and time estimates associated with changes to the LFAS Gate Closure from AEMO but considers that there is an opportunity to increase efficiencies in the WEM until the wider design changes are implemented through the ETS reforms.
11	Alinta	Alinta considered that the current gate closure times limit the flexibility of generators to take efficient actions in response to changing circumstances in the two hours leading up to real time. The gate closure times constrain both IPP's and Synergy's generators from responding dynamically to changing environmental and commercial conditions, meaning that higher cost plant may be dispatched when lower cost plant should be. For instance, if a planned generation outage finishes earlier than expected, a participant may not bring it back into service until after the two hours have elapsed. Other	The Rule Change Panel notes that forecasts of LSG are more accurate closer to real time (see section 6.1.3.2) and therefore agrees with Alinta that the current BGC limits the ability of Market Participants to respond to changing market conditions in the two hours ahead of the delivery interval, creating inefficiencies. The Rule Change Panel also agrees with Alinta that lengthier BGC periods delay the ability of Market Participants to return units to service, which can also lead to inefficiencies (see section 6.6.3).

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		capacity, which may have a higher marginal cost, would operate instead.	
12	Synergy	Synergy described the current differential gate closures as bereft of any analytical, or logical, basis as a market power mitigation measure. Synergy considered that the differential gate closures create inefficient economic signals, allow shadow pricing by other generators and therefore, discourage competition among generators, driving up the long-term costs of electricity. Synergy noted that there is no analysis of which Synergy is aware, that has examined the extent, if any, that such mitigation measures outweigh the inconsistency of the measures against the Wholesale Market Objectives. Specifically, Synergy noted that the limitations on when Synergy can make Balancing Submissions for the Balancing Portfolio appear to be inconsistent with the Wholesale Market Objectives of economic efficiency, encouragement of competition among generators and minimisation of the long-term cost of electricity supplied to customers from the SWIS. Synergy therefore considered that the Rule Change Panel should remove these Market Rules, which it described as discriminatory and economically inefficient.	See sections 6.2.2.2 and 6.2.2.4 of this report for consideration of whether Synergy should have the same gate closure as IPPs and discussion of market power mitigation, respectively.
Benefits of the Proposal			
13	AEMO	AEMO was concerned that shortening of the gate closure beyond 90 minutes in the absence of other changes to the market design may lead to unintended	See section 6.6.1.4 of this report for discussion of the cost of constraint payments.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		consequences, such as increased instances of constrained on/off compensation or declarations of High-Risk Operating States.	
14	AEMO	AEMO observed that Perth Energy's analysis of forecasting accuracy only included some basic statistics of forecast variation (maxima, minima and averages) based on the current gate closure time and did not assess the accuracy of forecasts at a 30-minute BGC. AEMO undertook an analysis of the 2016 calendar year, which was presented to the 1 May 2017 MAC meeting and showed that the accuracy of demand and price forecasts improved as the Trading Interval approached and that, as such, improvements in forecast accuracy are likely to be achievable by shifting BGC later. However, AEMO concluded that the improvements may not be as large as suggested by Perth Energy in its proposal. AEMO also noted that it was not aware of a reliable method of translating reductions in forecast error into estimates of market wide cost savings.	The Rule Change Panel notes that its analysis of forecast accuracy produced similar results to those produced by AEMO in its first period submission. See section 6.1.3.2. See also section 6.1.3.5 for discussion on quantifying the benefits of the proposal.
15	AEMO	AEMO noted that it would be expected that the improved forecast accuracy would result in cost savings for consumers due to improved decision-making by, and reduced risk for, Market Participants. AEMO advised, however, that attempts to quantify the savings would require speculative assumptions of behaviour changes and reductions in any risk premium incorporated in Balancing Submissions.	The Rule Change Panel agrees that there will be cost savings for consumers due to improved decision-making by, and reduced risk for, Market Participants, but that any estimates of savings would be dependent on making speculative assumptions about behaviour changes and changes in risk premiums incorporated in Balancing Submissions. See section 6.1.3.5 for discussion on quantifying the benefits of the proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
16	AEMO	AEMO observed that a later BGC would reduce the current delay when a generating unit returns to service following maintenance. AEMO explained that when low-cost generation returns from maintenance, it can displace higher-cost generation and reduce the Balancing Price. AEMO noted that the EMR highlighted this advantage in the *Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*, which estimated a recurring benefit of $300,000 per annum if the BGC was moved to 30 minutes before the start of the interval. AEMO suggested that a shift to a 90-minute BGC could realise approximately one-third of this benefit.	See section 6.6.3 for assessment of the cost and practicality of the proposal.
17	Alinta	Alinta considered that there are several benefits of reducing the gate closure, including: • Providing more flexibility for participants by increasing the ability of generators to take efficient actions in response to changing market circumstances, such as changes in demand and wind generation levels and forecasts, unplanned plant outages, early return from outages and unplanned transmission outages, and/or fuel supply constraints; • Assisting short term participation and risk management in the physical electricity market; • Enabling greater certainty for participants about their own fuel and plant status when making final submissions;	The Rule Change Panel agrees with the benefits identified by Alinta (see section 6.1.3.5).

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		• Reduced reporting, compliance, and administration costs, i.e. participants submitting revisions to bids between two hours (current gate closure) and the gate closure that is implemented will no longer have an obligation to report their reasons (noting that records will still be kept outlining any reasons for the rebids – as per the current rule requirements). Alinta noted that these benefits would lead to improvement in overall market efficiency and considered that the productive efficiency benefits of the additional flexibility would be considerable.	
18	Bluewaters	Bluewaters agreed that moving the BGC to 30 minutes before a Trading Interval would provide Market Participants with a greater opportunity to respond to forecast changes and enable making of more accurate trading decisions, which are likely to promote the economic efficiency of the Wholesale Electricity Market.	The Rule Change Panel agrees with the benefits of the proposal suggested by Bluewaters (see section 6.1.3.5).
19	Bluewaters	Bluewaters noted that the proposed reduction of BGC down to 30-minutes was intended to be an ongoing interim measure, while a sub-30 minute gate closure arrangement was being considered as part of the market reform. Bluewaters welcomed the opportunity to comment on this matter at the appropriate time.	The Rule Change Panel agrees with Bluewaters and notes that a sub-30-minute gate closure is being contemplated under the ETS, due for implementation from 2022.
20	Synergy	Synergy considered that the Rule Change Proposal should not be progressed in its current form because it has, at least, the following negative effects when assessed against the Wholesale Market Objectives:	See section 6.4 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		• It will increase the information asymmetry between Synergy and IPPs and therefore decrease economic efficiency; • It will increase the costs of LFAS and/or increase the risks to system security and reliability; and • It is unlikely to have any material impact on lowering the costs in the WEM - a position supported by the IMO when it assessed the same proposition (and, by operation of section 1.18 of the Market Rules, the Rule Change Panel is now deemed to have assessed it as such).	
21	Synergy	Synergy considered that there appeared to have been no evidence provided in the Rule Change Proposal that the gains in economic efficiencies from greater flexibility for IPPs to respond to load forecasts would outweigh what Synergy described as the 'economic inefficiencies associated with this obvious wealth transfer.' Synergy argued that the only evidence of the benefits provided appeared to be based on fundamentally flawed analysis, and specifically the fundamental assumption that all changes in the Balancing Price between the forecast price and the Final Price would be able to be avoided if a shorter BGC was implemented. Synergy considered that for such material benefits to be realised, there would need to be an, almost, unlimited amount of spare capacity available 30 minutes before BGC that was capable of providing electricity at the forecast price, that was able to be made available at much less than 30 minutes notice, and that was sitting idle at the time of the	See sections 6.1.3.2, 6.1.2 and 6.2.1 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		forecast. Synergy considered that this was obviously an extremely unlikely scenario.	
22	Synergy	Synergy considered that its proposition, that the benefits are significantly less than is claimed in the Rule Change Proposal, was supported by the analysis presented by AEMO at the MAC meeting, which seemed to indicate that the majority of the changes of the Balancing Price (and quantity) are due to forecast error, that are not known until real time. Synergy considered therefore, that irrespective of the changes to a shorter gate closer, the resultant changes to the Balancing Price could not be avoided.	See section 6.1.3.2 for the results of the Rule Change Panel's analysis of forecast accuracy.
23	Synergy	Synergy reasoned that, to the extent that the changes occur in real time, the energy could only be provided by Facilities already online and not at maximum capacity, or Facilities that have very short start up times (i.e. Facilities with "spare", and available, capacity). Synergy considered that, to the extent these Facilities exist, application of general market theory should mean that those Facilities have already made a Balancing Submission at a price at which they would be prepared to generate. Accordingly, the only benefit that the Rule Change Proposal could provide is limited to the extent that those Facilities have not already bid at a price that the relevant Market Participant would be prepared to operate. Synergy considered that the fact that it generally has the most in-merit Facilities already online that could provide energy at the Balancing Price	See section 6.1.3.1 for consideration of how access to more accurate information results in efficiencies in the WEM. The Rule Change Panel notes that Market Participants usually do not bid all of the capacity of a Facility with a minimum stable level of operation (minimum generation) at SRMC. This is because such a bid could lead to infeasible dispatch (e.g. where the Facility becomes the marginal unit and is dispatched below its minimum generation). Therefore, Market Participants usually bid: • a Facility's minimum generation at the Minimum STEM Price and only any quantities above the minimum generation at SRMC, if it expects a Balancing Price that would result in a profit for the Facility; and

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		compounds the over estimation of benefits in the Rule Change Proposal.	• all capacity at the relevant price cap if it expects a Balancing Price that would not result in a profit for the Facility. However, due to forecast inaccuracies, the Facility may end up being dispatched for its minimum generation at an unprofitable price or will not be dispatched even though the Balancing Price would have been profitable. Both outcomes are inefficient and a shorter gate closure will allow Market Generators to better manage this risk.
24	Synergy	Synergy considered that the EMR's claim of a $300,000 per year benefit, resulting from a shortened gate closure and reductions in the time IPP Facilities could return from Forced Outages, was incredibly optimistic. Synergy considered that in its 'extensive experience', a Facility operator will generally, know well in advance of two hours when its Facility will be able to return from a Forced Outage. Synergy considered therefore that the current BGC is sufficiently close to real time to realise most of the benefits claimed by the EMR.	See section 6.6.1 of this report.
25	Synergy	Synergy contended that any benefit capable of being realised due to the increased flexibility offered by the Rule Change Proposal would be orders of magnitude lower than the $50m+/year benefit claimed by Perth Energy, if it exists at all.	See section 6.1.3.5 for discussion on quantifying the benefits of the proposal.
26	Synergy	Synergy contended that while there is very limited benefit able to be realised in terms of increases to economic efficiency based on increased flexibility for	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market, including consideration of whether Synergy should have

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		IPPs, there is a vastly increased ability for IPPs controlling Facilities with flexible capacity (including capacity already committed) to bid in a manner that maximises their profits by shadow pricing against Synergy's locked in prices. Synergy considered that, with improved forecasts (no matter how slight), the risks for IPPs associated with shadow pricing are decreased and the logical result is that instances of shadow pricing and inefficient wealth transfers will increase. This outcome, according to Synergy, would further decouple the Balancing Price from the economically efficient pricing it should reflect, and further decrease the potential competition between the Balancing Portfolio and IPP generators, ultimately leading to higher costs for consumers. Synergy considered therefore, that unless the Rule Change Panel modifies the proposal to create the same gate closure times for the Balancing Portfolio as exist for other Market Participants, the Rule Change Panel should reject the proposed amendments to the Market Rules.	the same gate closure as IPPs (section 6.2.2.2) and market power and block bidding arrangements (section 6.2.2.4).
27	Synergy	Synergy contended that it is unclear how, under the Market Rules, AEMO can start to position plant up to 110 minutes ahead of the Trading Interval, given that it does not have a final BMO until just prior to the start of a Trading Interval. Synergy reasoned therefore, that the only Facilities to which AEMO could be referring are the Facilities within the Balancing Portfolio. Synergy considered that this appeared to be an acknowledgement by AEMO that it uses Synergy's	The Rule Change Panel acknowledges Synergy's concerns regarding the use of Synergy's Facilities to address the aggregate ramp issue. See section 6.1.7.3 for discussion of issues facing the Balancing Portfolio. See also section 6.2.1 for amendments to Synergy's gate closure for the Balancing Market.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Facilities to provide free LFAS. Synergy highlighted its concern that there is a significant risk that AEMO's use of this 'free LFAS' is only likely to increase if the Rule Change Proposal is progressed in its current form. Further, Synergy considered that, when combined with the obvious economic inefficiencies associated with AEMO dispatching the Balancing Portfolio on, and the Balancing Price often being set by, data that is up to 10 hours old, this inefficient cross-subsidy provides further support for Synergy's argument for an even playing field between the Balancing Portfolio and IPPs.	
Other Options for Enhancing Information Used in Trading Decisions			
28	Alinta	Alinta recommended that consideration should be given to amending the Market Rules to allow (but not require) Market Generators to update their wind forecasts after gate closure.	The Rule Change Panel notes that since Alinta made its submission, the requested change has been implemented with the commencement of Rule Change Proposal RC_2014_06 on 1 July 2019.
29	Bluewaters	Bluewaters considered that even with the shorter gate closure, accuracy of trading decisions may still be compromised due to the potential volatility and unpredictability of Intermittent Generators' outputs. Bluewaters noted that the current market arrangement does not provide accurate forecasts of Intermittent Generators' outputs and proposed making Market Rules to require AEMO to publish this information on a timely basis, to assist addressing the issue and further enhance the effectiveness of the shortened gate closure in achieving more accurate trading decisions.	See section 6.2.3 for discussion of other options for enhancing information used in trading decisions.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Amendments to Synergy's Gate Closure for the Balancing Market and the LFAS Market and the LFAS Gate Closure			
30	AEMO	In its submission, AEMO noted that Perth Energy had only proposed a change to BGC but did not appear to have considered the merits of changes to related market timeframes, particularly the LFAS Gate Closure and the deadlines for Synergy in submitting updated Balancing Portfolio Supply Curves. AEMO considered that market efficiency would be improved when all Market Participants are able to make operational decisions with the most accurate available information. Consequently, AEMO suggested that the Rule Change Panel consider the potential for amendments to these timeframes. AEMO noted that it did not foresee any additional operational challenges to those it had already mentioned in relation to the Rule Change Proposal if these timeframes were shortened proportionally.	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market. See section 6.2.2 for discussion of amendments to the LFAS Gate Closure.
31	Alinta	Alinta noted that under the current WEM design, Synergy continues to be subject to differential treatment i.e. it is able to bid as a portfolio in the energy markets, but the Market Rules provide it with fewer opportunities to revise its Balancing Portfolio Submissions (i.e., during five fixed periods each day) and these submissions are locked in ahead of IPP gate closure. Alinta considered that these timelines can lead to inefficient market outcomes. Alinta considered that it is not in the market's interest for Synergy to base its bids on potentially highly inaccurate information, or for its gate closure restrictions to	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market. See section 6.2.2 for discussion of amendments to the LFAS Gate Closure. The Rule Change Panel notes that Alinta later changed its position regarding replacing the 6-hour block-based gate closure for the LFAS Market with a rolling gate closure (see Appendix B). See section 6.1.3.5 for discussion on quantifying the benefits of the proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		adversely affect other market outcomes. Alinta considered that there will be benefits with amending the LFAS Gate Closure and the Balancing Market gate closure for the Balancing Portfolio. Alinta therefore recommended that consideration be given to replacing the 6-hour block-based gate closure for the LFAS Market with a rolling gate closure and changing Balancing Market gate closure for the Balancing Portfolio to a rolling gate closure. Alinta considered that this should be subject to a cost-benefit analysis, and the solution selected should not present an impediment to or delay a move to full Facility bidding.	
32	Alinta	Alinta advised that if the Balancing Market gate closure for the Balancing Portfolio was moved to a rolling gate closure it is still important that IPPs are able to update their Balancing and LFAS Submissions having seen the final position for the Synergy Portfolio and therefore, the gate closure times selected will need to allow for this.	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market and, in particular, section 6.2.1.4 for consideration of Synergy's market power. See section 6.2.2 for discussion of amendments to the LFAS Gate Closure.
33	Alinta	Alinta understood that the current arrangements were originally needed to facilitate a smooth transition to the new market arrangements[42] without risking system security and reliability, and to address concerns around market power. However, Alinta noted that its preference is that Synergy be required to make submissions for each of its Facilities so that it is dispatched on the same basis as other participants' Facilities (including the form	The Rule Change Panel agrees with Alinta's preference for Synergy to be dispatched on the same basis as other Market Participants and notes that Facility bidding is being contemplated under the ETS.

42 Alinta was referring to the new market arrangements implemented in 2012.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		of submissions, gate closure, surveillance etc.) as soon as practicable.	
34	Bluewaters	Bluewaters proposed that the Rule Change Panel assess the implication of reducing the BGC on Synergy's market power and give due consideration to whether the reduced gate closure should also be applied to Synergy. Bluewaters also considered that a shorter LFAS Gate Closure would promote economic efficiency in the WEM.	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market and (particularly section 6.2.1.4 for consideration of Synergy's market power). See section 6.2.2 for discussion of amendments to the LFAS Gate Closure.
35	Perth Energy	In Perth Energy's submission to the first submission period, it noted that it had undertaken further analysis in relation to the causes of significant variability in market outcomes over time, particularly price, and determined that movements in the Synergy Portfolio were a key contributor to this variability. Accordingly, Perth Energy suggested that the Rule Change Proposal could be further amended to allow Synergy to make rolling forecasts rather than fixed-point, and to reduce Synergy's Portfolio gate closure times commensurately with those proposed for other participants, for example, from six-hours to two-hours. Perth Energy reasoned that this would allow Synergy to more actively manage its Facilities, minimise volatility in the market and improve overall market efficiency, in accordance with the intent of Perth Energy's Rule Change Proposal. Perth Energy noted however, that practically, Synergy could remove Facilities from the Synergy portfolio to achieve later gate closure, should it be beneficial, and therefore implementation of the Rule	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market (particularly section 6.2.1.4 for consideration of Synergy's bidding arrangements).

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Change Proposal should not be unduly deferred for these changes.	
36	Synergy	Synergy considered that the Rule Change Panel must use this opportunity to create an even playing field between Synergy and IPPs in terms of BGC. Synergy considered that if it were able to offer prices on an even playing field with other Market Participants, the market would be able to realise the significant benefits associated with long-term price signals that reflect the cost of electricity production, without the negative consequences that are associated with information asymmetry embedded in the current Market Rules, and exacerbated by the Rule Change Proposal.	See section 6.2.1 for discussion of amendments to Synergy's gate closure for the Balancing Market and, in particular, section 6.2.1.2 for consideration of whether Synergy should have the same BGC as IPPs.
37	Synergy	Synergy considered that the gate closures (which it described as discriminatory) may have originally been introduced as a quid pro quo to offset Synergy's benefits associated with its ability to return Facilities from Outage materially earlier than other Market Participants. Synergy considered, however, that if the Rule Change Panel decided to move to a 30-minute BGC for IPP Facilities, then IPPs and Synergy (with respect to the Balancing Portfolio) would be able to return Facilities from Forced Outage at, effectively, the same time. Therefore, Synergy considers that, to the extent this basis for discrimination ever existed, it no longer exists in any material sense.	See section 6.2.1.4 for consideration of Synergy's market power. The Rule Change Panel has no comment regarding Synergy's speculation that the differing gate closures for IPPs and Synergy were intended to offset other benefits for Synergy under the Market Rules. However, the Rule Change Panel notes that Synergy cannot increase the available quantity (or prices) in its Balancing Submissions after its gate closure, but if a lower cost unit is ready to return to service after an outage there is nothing in the Market Rules to prevent AEMO from using that Facility rather than another Facility in the Balancing Portfolio to meet Synergy's dispatch obligations.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
38	Synergy	Synergy considered that it is a generally accepted economic principle that efficient markets require symmetrical information amongst Market Participants. Synergy stated that it was maintaining its long-held position that the current Market Rules requiring Synergy to offer its Balancing Portfolio into the Balancing Market at a gate closure materially longer than the gate closure for IPPs creates economically inefficient price signals, which results in decreases in dynamic economic efficiency, and, ultimately, higher prices for consumers. Synergy considered that the Market Rules that require all Market Participants to offer at SRMC where the behaviour relates to Market Power are sufficient to mitigate against market power abuses and result in economically efficient prices and outcomes, unlike the gate closures.	See section 6.2.1.4 for consideration of Synergy's market power.
39	Synergy	Synergy noted that the proposed reduction in BGC would reduce the current time lag for IPP Facility Balancing Submissions by 75%, but only reduce the time lag for the Balancing Portfolio by a maximum of 37.5%, and a minimum of 15% (due to Synergy's requirement to bid in six-hour blocks tied to the LFAS Gate Closure – see Market Rules 7A.2.9(d)). Synergy considered that the effect of this disproportionate change is that Synergy and IPP information becomes more asymmetric and therefore, there is a greater risk of economically inefficient wealth transfers from Synergy to IPPs, with no consequential benefit to consumers.	See section 6.1.2 for consideration of amendments to Synergy's Gate Closure.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Solutions to Address the Aggregate Ramp of IPPs			
40	AEMO	AEMO considered that there may be merit in staggering the start times of IPP Dispatch Instructions within a Trading Interval, without altering the end of interval MW targets. AEMO noted that this would reduce the need for positioning of the Balancing Portfolio to counter fast IPP ramping and alleviate the need for the ramping to be absorbed by LFAS (reducing the erosion of available Spinning Reserve that can occur within the Trading Interval). AEMO anticipated that such a change may enable the gate closure period to be shortened to 60 minutes, though further analysis was required to confirm this. AEMO observed, however, that such a change in operational practice may result in increased constrained on/off compensation payments as it deviates from the assumption in the Maximum/Minimum TES calculations that ramping commences at the start of the relevant Trading Interval. AEMO suggested that changes to these calculations are worthy of consideration as part of any exploration of this option. AEMO also advised that any analysis of this option should consider the impact of such a change on the revenues earned by generators.	The Rule Change Panel notes that AEMO's position regarding staggered ramping was later superseded by its plan to implement an automated linear ramping process from the date that a 60-minute BGC would commence. See section 5.5.1 for discussion at the 6 September 2019 MAC workshop in which AEMO introduced this plan and section 6.1.6 for the Rule Change Panel's assessment of AEMO's method for determining when linear ramping is required in the context of the 60- and 90-minute BGC options. See section 6.6.1 for consideration of costs associated with this proposal.
41	AEMO	AEMO considered that linearly dispatching generators at the ramp rate required to meet the MW target by the end of the Trading Interval was less favourable. AEMO anticipated that while linear ramping may reduce the pre-interval requirements to position the Balancing Portfolio	The Rule Change Panel notes that AEMO's original position on linear ramping was superseded by its plan to implement an automated linear ramping process from the date a 60-minute BGC would commence. See section 5.5.1 for discussion at the 6 September 2019

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		and reduce the pressure on LFAS, it would likely require additional implementation costs for AEMO and Market Participants, in addition to changes to calculations for constrained on/off compensation. AEMO observed that it may also be inconsistent with the broader WEM reforms proposed by the PUO.	MAC workshop in which AEMO introduced this plan, section 5.7 for out of session consultation with AEMO on the linear ramping solution, and section 6.1.6 for the Rule Change Panel's assessment of AEMO's method for determining when linear ramping is required in the context of the 60- and 90-minute BGC options. The Rule Change Panel notes that AEMO estimates the implementation of AEMO's automated linear ramping solution to: • cost $200,000; and • lead to constraint payments of between $1 million and $3 million per annum. The Rule Change Panel further notes that AEMO's linear ramping solution is expected to lead to costs for Market Participants to modify their generation units to allow for flexible ramping. See section 6.6.1 for consideration of costs associated with this proposal.
42	Alinta	Alinta acknowledged System Management's concern that a 30-minute (or less) gate closure may compromise System Management's ability to plan the system to allow movements to occur, whilst ensuring sufficient Ancillary Services are scheduled and ensuring the Synergy portfolio is positioned to meet the peaks and troughs. However, Alinta considered that, following discussions at the MAC meeting, it appears possible to reduce the gate closure without significant detrimental effects on these matters. Alinta noted that even in the current circumstances, there can be late 'bona fide' changes to	See section 6.1.2 for discussion of options for reducing the BGC.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		offers close to real time and System Management manages this risk effectively. Alinta considered that, as such, the security implications of a 30-minute gate closure period should be manageable, and noted further that, if required, System Management can call a High, or Emergency, Risk Operating State in order to resolve any Power System Security and/or reliability issues.	
43	Alinta	Alinta noted that, if System Management's concerns are unable to be mitigated sufficiently, the Rule Change Panel should seek to identify cost efficient solutions that will: • reduce the regulatory barriers that hinder participants from taking efficient actions to react to changing circumstances in the lead-up to real time; while • maintain the existing level of reliability of supply.	The Rule Change Panel notes Alinta's advice and considers that the additional changes to the proposed Amending Rules set out in sections 6.1 and 6.2 should meet these criteria, whilst allowing AEMO to meet its obligations within the current market design.
44	Alinta	Alinta considered that requiring linear ramping via the Market Rules would be problematic and costly to implement. Alinta noted that this option would cost in the order of $200k per unit to implement as it requires control system and governor changes. Alinta considered further, that there is the potential that these amendments would only be required for a short period of time as these changes would unlikely be required to support the market reform currently being contemplated by the Minister for Energy (i.e. security constrained five minute dispatch and co-optimised energy and Ancillary Services markets).	See section 6.6.3 for the Rule Change Panel's assessment of the practicality and cost implications of this proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Alinta stated that, given this, Alinta would not support the dispatch systems and Market Rules being changed to require the linear ramping of IPP Facilities. However, Alinta noted that, as discussed with the Rule Change Panel Secretariat on 24 May 2017, there could be other software changes that could be made outside the governor that could provide a solution to the IPP ramp rate issue and allow Facilities to support flexible ramping, in a significantly more cost effective manner. Alinta considered that this solution would require further assessment to understand if it is a viable solution.	
45	Alinta	Alinta noted that the RTDE currently provides Dispatch Instructions on a ten-minute basis. Alinta considered that consideration could be given to dispatching some Facilities ten or even twenty minutes into the Trading Interval, in order to alleviate System Management's issues with IPPs being dispatched at their maximum ramp rates at the start of a Trading Interval, and this resulting in combined IPP ramp rates that are sometimes three to four times higher than the ramp rate of the Balancing Portfolio. Alinta also considered that this solution would require further assessment to understand if it is a viable solution.	The Rule Change Panel notes that the implementation of linear or staggered ramping, which will require material changes to other functions such as the RTDE, the settlement Market Rules for calculating TES and constrained on and constrained off compensation, are beyond the scope of the Rule Change Proposal. See section 6.1.1 for discussion of the scope of the Rule Change Proposal. The option for linear ramping is only considered as part of this Rule Change Proposal because AEMO has indicated that it will implement linear ramping if the 60-minute BGC is implemented under this proposal (see section 5.7.2 for out of session consultation with AEMO on this topic). In contrast, AEMO has ruled out implementing a staggered ramping solution.
46	Alinta	Alinta considered that, if there isn't a cost effective technical solution to resolving System Management's	See section 6.1 for the Rule Change Panel's assessment of the 60- and 90-minute BGC options.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		system security concerns, the Rule Change Panel could, in its draft decision, look to amend the Rule Change Proposal to reduce the length of the BGC period from two hours to no more than one hour. Alinta suggested that this may provide a balanced solution, which addresses the trade-off between capturing the benefits of flexibility and managing system security. Alinta considered that this solution would also allow a move to a 30-minute (or less) gate closure as time, and circumstances, allow.	
47	Alinta	Alinta suggested that each of the options that it suggested for consideration by the Rule Change Panel to address the aggregate ramp issue should be subject to a cost-benefit analysis to identify the most appropriate solution.	See section 6.1.3.5 of this report.
48	Synergy	Synergy noted AEMO's ability to use LFAS, either expressly through the LFAS Markets or by dispatching Facilities within the Balancing Portfolio, will be reduced if the BGC is reduced to 30 minutes or less. Therefore, Synergy considered that, to the extent AEMO is required to use LFAS to allow for these large movements in Facility output to occur, in order to maintain the system in a secure and reliable manner, AEMO will have to: 1 Increase the formal LFAS Requirement for all Trading Intervals where there is a possibility of significant changes in the output of multiple	See section 6.1.7.2 of this report for discussion of the increasing need for LFAS and section 6.1.7.3 for discussion of issues facing the Balancing Portfolio. The Rule Change Panel notes that AEMO proposed a sculpted LFAS Requirement in its Ancillary Services Report for the WEM 2019[43] (for the 2019-20 Financial Year) with 85 MW between 5:30 AM and 7:30 PM, and 50 MW between 7:30 PM and 5:30 AM, for both LFAS Upwards and Downwards.

43 See; https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Facilities (i.e. pay for significantly more LFAS and leave that LFAS idle almost all of the time); 2 Increase the availability and dispatch of ultra-flexible plant within the Balancing Portfolio; 3 Increase the likelihood of insufficient LFAS being available when needed; or 4 Adopt a sculpted LFAS Requirement. Synergy considered that outcomes 1 to 3 are obviously economically inefficient and/or pose an increased, and unacceptable, risk to Power System Security and reliability. Synergy understood that the current Market Rules already allow for a sculpted LFAS Requirement but noted that it appeared that AEMO chooses to use the Balancing Portfolio to provide the extra LFAS instead. Therefore, Synergy considered that the Rule Change Panel should amend the Market Rules to have an express requirement for AEMO to use a sculpted LFAS Requirement, and not to use the Balancing Portfolio in a manner different to other Facilities.	
The GIA Solution			
49	Perth Energy	In its submission to the first submission period, Perth Energy noted that since it had lodged its Rule Change Proposal, further information had become available regarding the GIA solution. Perth Energy understood that: • a tool would be developed by Western Power to run in parallel to the market to review the loading on	The Rule Change Panel notes Perth Energy's concerns regarding implementation of the GIA tool and the impact that it would possibly have on market outcomes. The Rule Change Panel does not have access to information on the effect of the GIA tool on market outcomes since its implementation and is therefore unable to comment on this topic. The Rule Change

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		network elements every few minutes and determine how GIA generators can be dispatched; and • the intention was for each GIA generator to have the price quantity pairs inserted into the market bid stack after BGC. According to Perth Energy, this would mean that the forecast quantities and prices of all GIA generators would be absent from the market, making outcomes highly volatile, and significantly increasing risk for non-GIA participants by preventing them from responding to accurate price signals. Perth Energy considered that this would be a significant contributing factor to accurate pricing and participation in the market and suggested therefore that the Rule Change Proposal could be further amended to remove the BGC altogether, allowing Market Participants to respond to changes in quantities and prices until the commencement of the relevant Trading Interval, including to movements of GIA generators. In support of this, Perth Energy noted that System Management had apparently accepted the high-level design of Western Power's GIA solution at that time, including the inherent need for its operators to continually assess and re-dispatch Facilities every few minutes. Perth Energy considered therefore, that System Management could accommodate short-term changes in dispatch such as those required under the Rule Change Proposal, and those required with the removal of gate closure, despite System Management voicing its	Panel further notes that changes to the GIA tool itself are beyond the scope of this Rule Change Proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		reluctance. Perth Energy considered that amendments to remove BGC would better achieve the Wholesale Market Objectives.	
50	Perth Energy	In its out of session submission, Perth Energy proposed that the urgency rating of the Rule Change Proposal be amended from a medium to a high urgency rating. In relation to the GIA, Perth Energy noted that Western Power had advised that: • The GIA arrangement would now cover up to eight new generators with a maximum capacity of 900 MW, which was larger than the 400 MW that was originally intended. • Rather than being a short term solution that would be replaced by AEMO's market tools in mid-2019, the GIA would remain in place for at least four years, much longer than originally planned, as the new access arrangements will not be in place until October 2022 at the earliest. • Western Power's modelling of the GIA arrangement showed that it would cause increased inaccuracy for the forecast Balancing Price. Perth Energy contended that this would accentuate the inaccuracies in the load forecast and that the implementation of a "pre-dispatch" tool that operates during the current gate closure creates "firm" and "non-firm" pricing. According to Perth Energy, this would cause the cost of supply to customers to rise due to Generators not being able to optimally bid into the	The Rule Change Panel notes Perth Energy's concerns regarding implementation of the GIA tool and the impact that it would possibly have on market outcomes. The Rule Change Panel does not have access to information on the effect of the GIA tool on market outcomes since its implementation and is therefore unable to comment on this topic. The Rule Change Panel further notes that changes to the GIA tool itself are beyond the scope of this Rule Change Proposal. However, the Rule Change Panel notes that, at the MAC meeting on 13 June 2018, the MAC decided against amending the urgency rating of this Rule Change Proposal and as such, that the Rule Change Proposal still has a medium urgency rating.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Balancing Market and pricing in the added risks, and to an excessive reliance on Ancillary Services. Perth Energy considered that the increase in load and price inaccuracy that the GIA would bring to the market for the next four years was unacceptable for WA's energy consumers, who pay the price for the inaccuracy and for inefficient dispatch. Perth Energy observed that the growth in behind-the-meter solar PV installation had continued and that the issue of forecast inaccuracy in load and price was becoming acute. Perth Energy also noted that AEMO had recently advised that the cost for Ancillary Services was running at around $8 million per month (~$100 million per year), and that there was also a question as to whether Synergy was actually receiving correct payment for Spinning Reserve and LFAS. Perth Energy considered that the level of forecasting error directly influences both actual and hidden costs, leading to the expectation that the changes to the GIA and continued strong solar growth would push them still higher. Perth Energy concluded that the most effective way to minimise the problem, without having to replace the dispatch engine earlier than 2022, is to reduce the timeframe over which forecasts are made. Perth Energy acknowledged that moving to 30-minute gate closure would provide challenges and was most likely contingent on Synergy moving to Facility dispatch from the current portfolio dispatch and that it would reluctantly, support a 60-minute gate closure. Perth Energy stressed,	

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		however, that this would deliver less benefits to AEMO, generators and customers, and should be an interim move.	
Other Issues			
51	Synergy	Synergy considered that the only way that the WEM can move to a BGC of 30 minutes or less without increasing economic inefficiencies in the market and/or increasing risks to system security and reliability is to: • Allow for all Balancing Facilities to have the same gate closure for making Balancing Submissions; and • Require AEMO to "sculpt" the LFAS Requirements while redrafting the Market Rules to expressly prohibit it from using the Balancing Portfolio to, effectively, provide "free" LFAS. Synergy considered that if the Rule Change Panel decided to progress the Rule Change Proposal without modifying the proposal, it would have little choice but to submit a competing Rule Change Proposal to remedy the economic inefficiencies. Synergy requested formal notification as soon as possible if the Rule Change Panel intended to proceed in this manner.	See section 6.2.1.2 for discussion of whether Synergy should have the same gate closure as IPPs. The Rule Change Panel notes that AEMO proposed a sculpted LFAS Requirement in its Ancillary Services Report for the WEM 2019 (for the 2019-20 Financial Year) with 85 MW between 5.30 AM and 7.30 PM, and 50 MW between 7.30 PM and 5.30 AM, for both LFAS Upwards and Downwards. See section 6.2.1 for the Rule Change Panel's assessment of proposed amendments to Synergy's gate closure for the Balancing Market.
52	Synergy	Synergy considered that the decision by the Rule Change Panel to progress the Rule Change Proposal in its current form created unnecessary, and unacceptable, regulatory costs for all Market Participants, as the proposal contains unsubstantiated claims of benefit and there is ample external evidence available to the Rule	The Rule Change Panel notes that it is obligated to assess the cost and practicality of a Rule Change Proposal even if the submitting party provides its own assessment.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Change Panel demonstrating that the proposal would not be of material benefit to the market. Synergy expected that a Rule Change Proposal would contain substantial analysis and justification explaining why the Rule Change Panel should progress the particular proposal and that the Rule Change Panel would make a preliminary assessment of the adequacy of the proposal before providing it to the broader market for review and comment.	The Rule Change Panel disagrees with Synergy's statement that it is obvious that the proposed changes would not be of material benefit for the market.
53	Synergy	Synergy considered that, in this instance, the proposal: • Obviously increases information asymmetry (and therefore increases the associated economical inefficiencies, as well as decreases competition amongst generators); • Used obviously flawed analysis in its statement of benefits to the market; • Provided no evidence of the costs and benefits of the trade-off between its stated benefits and the decreases in economic efficiency (from the increases in information asymmetry and decreases to competition amongst generators); and • Did not address the many issues publicly identified as being associated with its proposed changes to the Market Rules. Synergy considered that Rule Change Proposals such as these are inconsistent with good regulatory practice and should not be permitted to progress without significantly more analysis. Synergy stated that an	See the Rule Change Panel's response to issue 52 regarding the progression of the proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		undeveloped Rule Change Proposal requires Market Participants to conduct the required analysis, rather than initially require Perth Energy to provide a more detailed proposal. This has the effect of pushing the cost of the analysis onto the rest of the market, with multiple Market Participants potentially completing the same analysis in multiple submissions, increasing inefficient regulatory burdens upon the rest of the market.	
54	Synergy	Synergy considered that the Rule Change Panel had independent expert advice stating that a change such as this is unlikely to have any material benefit to the market. In support of this, Synergy cited a paragraph from the EMR Final Report noting that manual intervention is required to manage network congestion, which is operationally burdensome and increases the likelihood of errors or inefficient dispatch, and the slow speed of such manual processes hinders efficiency improvements to the existing market design, such as later gate closure, a shorter dispatch cycle or co-optimisation of energy and Ancillary Services. Synergy considered that this appeared to imply that, if AEMO does not make other changes concurrently to its systems, the proposed shorter BGC would lead to a decrease in system security and reliability. Synergy considered that the Panel's decision to progress the Rule Change Proposal in the face of documented evidence of increases to system security and reliability risks (a Wholesale Market Objective), without the proposal even addressing the	See the Rule Change Panel's response to issue 52 regarding the progression of the proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		issue, added to Synergy's concerns at the low bar required to progress a Rule Change Proposal.	
55	Synergy	Synergy considered that there was sufficient information available to the Rule Change Panel for it to require Perth Energy to formulate and re-submit a credible, coherent Rule Change Proposal. Synergy contended that the Rule Change Panel should require a higher standard of Rule Change Proposals where they deal with matters that have previously been the subject of extensive, and expensive, public consultation and debate.	See the Rule Change Panel's response to issue 52 regarding the progression of the proposal.
56	Synergy	Synergy noted that, as a matter of process, it is concerned that Market Participants and other submitters of Rule Change Proposals may not have sufficient guidance from existing policies and procedures that explain the level of detail and substantiation required of a Rule Change Proposal before it can be progressed for review by other Market Participants and the Rule Change Panel. Synergy considered that it is also possible that current policies do not adequately detail the principles that the Rule Change Panel should apply before allowing a Rule Change Proposal to progress for industry comment.	See the Rule Change Panel's response to issue 52 regarding the progression of the proposal.

Appendix B. Submitting Parties' Advice to the Panel Following the 6 September 2019 MAC Workshop

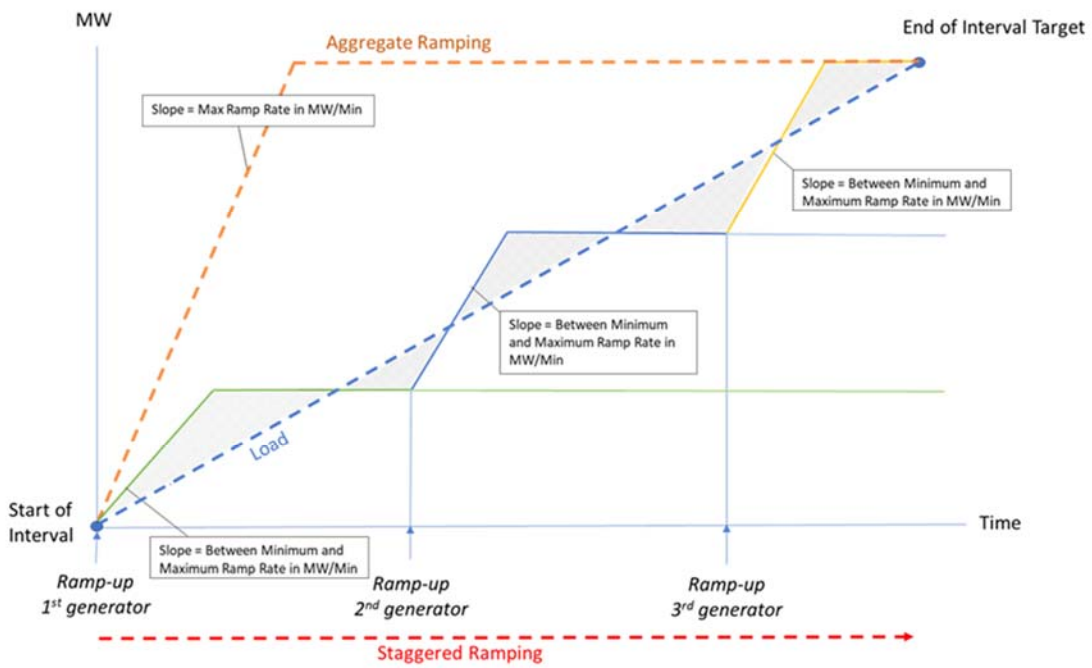
Submitter	Feedback
Question 1	**What is it that Market Participants would like to advise the Rule Change Panel to do regarding System Management's proposal for linear ramping, considering the timeframe for implementation, and the options to move to a 60- or 90-minute BGC?**
AEMO	AEMO requested that the Rule Change Panel consider the costs of linear dispatch in the determination of the appropriate gate-closure. AEMO noted that it would provide an indication of relative constrained-off payments between a 90-minute and 60-minute gate-closure. AEMO noted that it hoped to do this by the end of September and considered that if this information did not provide sufficient ability to inform the Rule Change Panel's final decision, it could then investigate the system implementation costs. However, AEMO noted that it did not propose to investigate the system implementation costs without a firm requirement by the Rule Change Panel due to the costs of scoping a solution.
Bluewaters	Bluewaters noted that strawman option 3 is its preferred option if a change is to be made (refer to slide 19 from the 6 September MAC workshop slides available on the Rule Change Panel's website).
ERM	ERM noted that it appears that System Management believes that it will be able to implement linear ramping without this rule change. ERM considered that, if this was the case, it would need certainty on when System Management decides to actually operationalise and use linear ramping to give ERM a timeframe to determine if it needs to make changes to how its logic operates and to implement those changes.
Kleenheat	Kleenheat considered that shortening the timeframes for BGC will improve the economic efficiency of the WEM and the ability of the market to respond more quickly to unexpected events with accurate price signals. However, Kleenheat asked the Rule Change Panel to carefully assess the possible additional costs incurred by Market Participants (including retailers) in the context of rising market operation costs to accommodate the WEM reform program in the coming years. Kleenheat noted that a 90-minute BGC is understood to be achievable at minor costs but that this is not the case for a 60-minute BGC. Kleenheat recommended that the Rule Change Panel undertake a cost-benefit analysis of the 60 and 90-minute BGC options to support the decision-making process. Kleenheat further considered that aggregate ramping appears to be more and more inadequate in the context of the increasing penetration of intermittent Non-Scheduled Generation. Kleenheat noted that more LFAS capacity must be on

Submitter	Feedback
	standby in real-time to compensate for deviations from the aggregate ramping schedule and the varying output of renewable energy sources, which leads to excessive and unnecessary costs for the market. Kleenheat was in favour of linear ramping. Kleenheat noted that linear ramping would allow System Management to accurately incorporate and use the ramping capability of Scheduled Generators, whilst not requiring additional Ancillary Services, at a cost to the system. Kleenheat noted that it believes that linear ramping can be one of the solutions to make sure energy demand is met during each Trading Interval at minimal cost to the market.
Synergy	Synergy considered that either a 60-minute or a 90-minute gate closure would represent an improvement to the current arrangements. Synergy noted that it could operate under either arrangement, but on balance, it preferred a 60-minute gate closure. Synergy considered that linear ramping should be adopted irrespective of which gate closure timing is chosen, and that it is neither appropriate nor efficient to accommodate IPP movements at their maximum ramp rate through intra-interval adjustments to the Balancing Portfolio that are manifestly inconsistent with the portfolio's end-of-interval targets. Synergy advised that with the changing SWIS load profile, and as the instances of the portfolio being dispatched at minimum generation levels increase, it is unlikely that portfolio movements will be able to accommodate IPPs moving at maximum ramp rates without impacting the provision of essential system services.
Question 2	**What are the implications of linear ramping for your units?**
Alinta	Alinta noted that it will likely to be able to implement linear ramping for a 30-minute Trading Interval for its Scheduled Generators, but it will likely cost in the order of $200,000 per unit, as it would require both control system and governor changes. Alinta noted that it will also require scheduling a planned outage, which is not in Alinta's current asset management or outage plans. Alinta considered further, that there is the potential that changes to support linear ramping for a 5 minute dispatch interval (to support the market reform currently being contemplated) could be implemented differently to linear ramping over a 30-minute interval and, therefore, that the costs for implementing the changes should be considered, taking into account the changes required for market reform. Alinta noted that, as it raised in the workshop, governors are generally tuned for a specific ramp rate, so there are limits to the variability that a unit could ramp at before causing instability to the Facility and therefore the system.

Submitter	Feedback
Bluewaters	Bluewaters considered that, commercially, there will be an impact from linear ramping on Facilities. Bluewaters explained that if you are increasing generation and are slowed down, you would lose out on MWh and if you are dropping generation and are slowed down, you generate at a price higher than the market price for longer. Bluewaters also advised that, technically, the control systems of both plants (Bluewaters and NPK) will need modifications. Bluewaters noted that the steam turbines at both plants will likely need different control valves to throttle steam flow to limit/control ramps. Bluewaters considered that these valves will also require more maintenance and inspections, with a reduced time between inspection intervals, given the increased throttling. Bluewaters noted, additionally, that restricting the ramp rate of quicker moving plant may introduce a higher likelihood of non-compliance for over generation and outages for under generation, as the tolerance levels will be reduced given the lower ramp rate.
ERM	ERM considered that the implications of linear ramping are increased or potentially prolonged inefficient operation within an interval, which might put ERM out of the money. ERM noted that it will want to ensure that if and when there is a move to linear ramping, it has access to either constrained off or constrained on payments so that it is not penalised financially for having to burn significantly more fuel than it would otherwise expect to burn.
Synergy	Synergy considered that, subject to appropriate control by AEMO, the portfolio ought to be able to accommodate linear ramping.

Submitter	Feedback
Question 3	**Is staggered ramping a suitable option for addressing the aggregate ramp issue and what should this approach look like (i.e. who should be delayed, when should they be delayed and by how much should they be delayed?) Are there any other constraints that need to be implemented to ensure that the benefits of this approach outweigh the costs?**
AEMO	AEMO noted that it had not considered the costs or feasibility of staggered ramping. However AEMO considered that staggered ramping: a) will not resolve the issue where the individual IPP ramp rates exceed the Balancing Portfolio's capability; b) is difficult to implement; c) will require new Market Rules to determine the ordering of Facilities; d) may prevent a Facility reaching its BMO Quantity, with consequential Power System Security issues and Market Rule compliance implications for both AEMO and the participant; and e) will require an automated system that is far more complex than for linear ramping. AEMO considered that, on balance, linear dispatch appeared to be a superior solution.
Alinta	Alinta considered that staggered ramping may be a suitable option as it will not require any control system or governor changes. However, Alinta noted that it may be more costly to the market if constrained off payments are paid to the generator that has been instructed to ramp up at a later time. Alinta considered further, that if constraint payments are not paid, it is likely that all generators would want to ramp from the start of the interval, rather than being delayed (and incurring the loss of income from reduced generation). Alinta advised that if staggered ramping was to be implemented, the units with a lower ramp up rate should be ramped up first to minimise the difference between generation and demand.
Bluewaters	Bluewaters considered that staggered ramping would appear to be a more complex resolution that poses additional questions to resolve, making linear ramping a better option for simpler implementation (noting that it still is not simple in itself).
ERM	ERM considered that it sounded like staggered ramping is not preferred by AEMO and that, given this, staggered ramping should not be considered. However, ERM expects that there would have to be Market Rules around who gets ramped first, as the generator that ramps first will receive its expected revenue while the generator that ramps later will be penalised financially.

Kleenheat	Kleenheat considered that staggered ramping can be an appropriate solution for system security and that the Rule Change Panel should consider updating policies and standards that allow new ranges for system security requirements, including staggered ramping. Kleenheat suggested further, that the Rule Change Panel needs to make sure all participants are treated fairly in the case of delayed ramping (up or down), with constraints and limitations shared equally between Facilities. Kleenheat asked the Rule Change Panel to make sure that LFAS is used for system security only and considered that any unnecessary use of LFAS (i.e. for ramping issues) should be avoided, which would eventually minimise the total cost for the market. Kleenheat noted that it believes that clear and binding instructions containing EOI Quantity (in MW) and ramp rate (in MW/minute) should be issued by System Management to every Facility for each Trading Interval and that the recovery cost of LFAS should be allocated to those Market Participants that might excessively breach Dispatch Instructions, so that the unnecessary use of LFAS is avoided. Kleenheat provided the schematic below, depicting a possible optimal dispatch of Facilities within a Trading Interval. Kleenheat recommended that the Rule Change Panel allow a combination of linear ramping and staggered ramping to reach the optimal dispatch. Kleenheat clarified that, by optimal dispatch, it meant a least cost dispatch, which does not compromise system security through unnecessary use of LFAS or other contingency mechanisms, corresponding to a minimisation of the grey areas on the graph.

Submitter	Feedback
	
Synergy	Synergy did not consider staggered ramping to be an appropriate way to accommodate the aggregate ramp issue. Synergy noted that an equitable approach to staggered ramping would increase the complexity of both the Rule Change Proposal and of implementation, delaying the delivery of market benefits. Synergy considered that linear ramping, applied in all cases, is simple and transparent.
Question 4	**What is it that other Market Participants need to do following Synergy's gate closure and before BGC, and how long does this take?**
Alinta	Alinta advised that Market Participants need to review prices and internal positions, then potentially submit a variation Balancing Submission based on the impact of Synergy's latest submissions. Alinta considered that this would take at least 60-minutes, based on when Synergy's final Balancing Submission was submitted. Alinta noted that submissions made within

Submitter	Feedback
	approximately five minutes before BGC are not used to create the next BMO. According to Alinta, this means that the next BMO created, which takes Synergy's Balancing Submission into consideration, is approximately 35 minutes after the submission and once the BMO is created, Market Participants would need 30 minutes to revise their Balancing Submission, as necessary. To demonstrate this, Alinta provided the following example: • 08:56: Synergy submits Balancing Submission for Trading Interval (TI) 12:00 onwards. • 09:00: Updated BMO is created but does not consider Synergy's Balancing Submission made at 08:56. • 09:30: BMO is created which considers Balancing Submission made at 08:56. • 09:35: Market Participants can review the changes made to TI 12:00 onwards and submit a variation Balancing Submission if required. Alinta considered that this example shows that the time difference between Synergy's gate closure for the Balancing Market and BGC should be at least 60 minutes.[44]
Bluewaters	Bluewaters considered that, following Synergy's gate closure, IPP's review forecast pricing and BMO positions to ensure their Balancing Submissions reflect all information available (internal and external), and provide for optimal dispatch, based on costs, and avoid any infeasible forecast dispatch. Bluewaters advised that it generally takes around 1.5 hours to ensure all intervals in the short-term horizon are correct. Bluewaters noted that, importantly, these changes need to be reflected in the BMO published by AEMO at least 30 minutes prior to BGCs to review and make subsequent amendments.
Synergy	Synergy noted that, while it had no view on the differential desired by IPPs with respect to the Portfolio BGC, it considered that gate closure for the Balancing Portfolio should be as short as practicable to: • provide the most accurate information to the market; and • ensure consistency between Synergy's offer pricing and the units that are dispatchable in real time (considering minimum recall times, start profiles, minimum stable levels of units (especially of units that are slow to load) and other technical constraints).

44 In consultation with RCP Support on whether Synergy's submissions made within five-minutes before BGC are used to create the next BMO, Alinta concluded that its comments in relation to this point were irrelevant. However, Alinta continued to advocate for a 1-hour period between Synergy and other Market Participants' gate closure times, as the Market Rules specify AEMO has 15 minutes into an interval to publish an updated BMO. Alinta considered that this may potentially give participants only 15 minutes to review and respond to changes, which may not be enough time.

Submitter	Feedback
	Synergy considered that ideally, the Balancing Portfolio should have the same gate closure as IPPs.
Question 5	**Would a rolling gate closure for Synergy affect other Market Participants and, if so, how?**
AEMO	AEMO noted that it has no Power System Security concerns with a rolling gate closure for Synergy.
Alinta	Alinta considered that it will not affect other Market Participants if the BGC is at least 60-minutes after Synergy's gate closure.
Bluewaters	Bluewaters explained that rolling Synergy's gate closure would require a rolling review of the IPP processes that it outlined in response to question 4 and further requirements to review all market information more frequently, and therefore additional costs to be recovered from the Balancing Market. Bluewaters considered that whilst these changes do not necessarily introduce more uncertainty (as Synergy positions will still be locked in after a gate closure) it does not introduce additional requirements for IPP's, more than currently exist.
ERM	ERM considered that a rolling gate closure would allow Synergy to change its bids and offers more often and closer to real time, which means that Market Participants may find themselves changing bids and offers more often than previously. ERM considered that if that is not a concern, then it's probably alright to allow Synergy to have a rolling gate closure. ERM noted that it would only advocate this if there is a gate closure time difference for Synergy and Market Participants, as Synergy should not have the same gate closure time as Market Participants while it is still bidding on a portfolio basis.
Kleenheat	Kleenheat considered that a rolling gate closure for Synergy would improve the efficiency of the market, as Synergy would have the opportunity to submit bids closer to the delivery time and Price-Quantity Pairs provided by Synergy would be based on more accurate market information, reducing the uncertainty of Synergy's decision. Kleenheat further considered this would lead to lower risks and, ultimately, to better price signals.
Question 6	**Should we reduce the timeframe between LFAS Gate Closure and Synergy's gate closure and, if so, by how much?**
AEMO	AEMO questioned whether changes to LFAS are within the scope of this Rule Change Proposal. However, AEMO noted that it has no Power System Security concerns regarding the timeframe between LFAS and Synergy (or IPP) gate-closure and considers that a shortened gate-closure would reduce forecasting error. AEMO advised that the WEM design requires that LFAS Gate Closure must be before BGC for both Synergy and IPPs.

Submitter	Feedback
Alinta	Alinta advised against reducing the timeframe between LFAS Gate Closure and Synergy's gate closure in the rules. Alinta considered that 60 minutes will allow Synergy to assess their LFAS Enablement for the next block, assess their portfolio position and submit corresponding Balancing Submissions.
Bluewaters	Bluewaters noted that it is indifferent as to whether to reduce the timeframe between LFAS and Synergy's gate closures, but the ability to reduce the gate closure further by reducing this gap would be beneficial.
ERM	ERM noted that, given that consideration is being given to a shorter gate closure period and a rolling gate closure for Synergy, it makes sense for LFAS Gate Closure to also be bought closer to real time. ERM considered that the gate closure being as far out as it currently is does not make sense, and that if Synergy has a reduced gate closure for LFAS, then Market Participants should also have a reduced gate closure for LFAS. ERM advocated that a timing difference should remain for LFAS Gate Closure for both Synergy and Market Participants.
Kleenheat	Kleenheat was in favour of reducing as much as possible the timeframe between LFAS Gate Closure and other Market Participants' gate closure (including Synergy), which would improve the economic efficiency of the WEM, minimising the total cost of supply for the market. Kleenheat considered that the Price-Quantity Pairs provided through LFAS and Balancing Portfolio submissions would be based on more accurate market information and would reduce the uncertainty of those submissions, leading to lower risks and better price signals.
Synergy	Synergy considered that a minimum 60-minute lag between LFAS Gate Closure and BGC is required to allow participants sufficient time to incorporate LFAS clearing volumes in balancing offers.
Question 7	**What is it that Synergy needs to do following the LFAS Gate Closure and why?**
Synergy	Synergy noted that after LFAS Gate Closure, it may need to update its balancing offers to reflect LFAS clearing volumes, which generally requires a re-run of Synergy's dispatch and pricing models.
Question 8	**What is it that other Market Participants need to do following the LFAS Gate Closure and why?**
Alinta	Alinta considered that Market Participants will need to assess their LFAS Enablement, make corresponding Balancing Submissions reflective of their LFAS Enablement and prepare units to provide LFAS if required.

Submitter	Feedback
Bluewaters	Bluewaters noted that, following LFAS Gate Closure, IPP's will review LFAS selection information and make the required adjustments to Balancing Submissions under the Market Rules (enabled volumes are priced at MIN and MAX) and adjust generation levels to ensure the generation asset is capable of providing the LFAS service (ensure higher or lower load levels to ensure physical response is compliant with Market Rules). Bluewaters considered that IPP's may also need to review the dispatch of associated generation Facilities to ensure sufficient energy is also dispatched to meet their customer requirements if capacity has now been reserved for LFAS provision.
Question 9	**Would a rolling LFAS Gate Closure affect Market Participants and, if so, how?**
AEMO	AEMO questioned whether changes to LFAS are within the scope of this Rule Change. However, AEMO noted that it has no Power System Security concerns with a rolling LFAS Gate Closure and considered that a rolling gate closure would reduce forecasting error. AEMO advised that the WEM design requires that the LFAS Gate Closure must be before the BGC for both Synergy and IPPs.
Alinta	Alinta noted that, as a result of key learnings and market experience following Alinta's entry into the LFAS market, Alinta's view on LFAS Gate Closure had changed since its initial submission on this Rule Change Proposal. Alinta considered that a rolling LFAS Gate Closure may have high implementation costs or may lead to inefficient or non-compliant outcomes because changes in LFAS Enablement require corresponding Balancing Submissions for Facilities to be dispatched optimally. Alinta advised that having a rolling LFAS Gate Closure means personnel (traders) will need to check changes in LFAS Enablement every 30 minutes and if personnel fail to check and reflect changes in LFAS Enablement, it would either lead to non-compliance or the Facility being underutilised, as it may have provisioned some capacity for LFAS which was not enabled. To demonstrate, Alinta provided the following example for Trading Interval 06:00 where a generator has a maximum capacity of 250 MW. In Scenario 1, LFAS was initially enabled for 10 MW LFAS Up and 10 MW LFAS Down. The Balancing Submission would reflect maximum dispatchable generation to 240 MW, as 10 MW is provisioned for LFAS Up. At 02:00, LFAS Up was no longer enabled as another Market Participant offered LFAS Up at a lower price. The trader should make a corresponding Balancing Submission to dispatch the Facility back to 250 MW as it will no longer be providing LFAS. If the trader fails to make a corresponding Balancing Submission, the market and the generator would have 'lost' 10 MW of dispatchable energy, resulting to higher Balancing Prices. In Scenario 2, 10 MW LFAS Up and 10 MW LFAS Down is offered in the LFAS market but is not enabled. The Balancing Submission would reflect maximum dispatchable generation to 250 MW as LFAS was not enabled. At 02:00, LFAS Up is now

Submitter	Feedback
	enabled for 10 MW as another participant has decided not to offer LFAS. The trader should make a corresponding Balancing Submission to dispatch the Facility to 240 MW, as it will need to provision 10 MW for LFAS Up. If the trader fails to make a corresponding Balancing Submission to reflect the LFAS Enablement, the generator may be dispatched to 250 MW and will not be able to provide LFAS Up, as it has been enabled, leading to non-compliance with the Market Rules. Alinta considered that the issues in the scenarios above can be mitigated through a systemised solution but it would be costly to implement. Alinta also noted that the issues should be resolved with the market reform as energy and essential system services will be co-optimised.
Bluewaters	Bluewaters considered that a rolling LFAS Gate Closure would provide additional opportunities to ensure optimal dispatch and respond to price signals but that this would also introduce additional costs associated with the increased trading efforts.
Kleenheat	Kleenheat considered that a rolling LFAS Gate Closure would improve the economic efficiency of the WEM by reducing forecasting error and speeding up responses to unexpected events.
Synergy	Synergy noted that, due to the requirement for Balancing Submissions to reflect LFAS clearing volumes, any change to LFAS clearing volumes may require a participant to update their Balancing Submission. Synergy considered that it is likely that the frequency of Balancing Submissions for LFAS participants will increase significantly and for this reason, Synergy considered it is desirable to retain the current LFAS 6-hour (or similar) block structure.

Appendix C. Analysis of Forecast Accuracy Closer to Real Time

Appendix C summarises the main outcomes of the Rule Change Panel's analysis of forecast accuracy. Forecasts were considered for the following variables:

- Load for Scheduled Generation (**LSG**), which is the total end of interval quantity attributable to Scheduled Generators in the SWIS, measured in MW;
- Non-Scheduled Generation (**NSG**), which is the total end of interval quantity attributable to Non-Scheduled Generators in the SWIS, measured in MW. Two types of NSG forecasts were considered:
    - forecast NSG based on information provided in Market Participants' Balancing Submissions;
    - Persistence NSG, which was the forecast for a target delivery interval based on the actual NSG observed in the preceding Trading Interval; and
- Final Price, which is the final Balancing Price, representing the cost of providing the balancing energy, measured in $/MWh.

Data Extraction and Screening

Actual data was extracted for the 2017 to 2019 period for each of type of forecast, for each Trading Interval from the Balancing Market summaries available on AEMO's website.[45] Actual data was also extracted for the 2016 period for NSG.

AEMO provided the Rule Change Panel with twenty forecasts for each actual value of NSG, Final Price and Total Generation, which is the total end of interval quantity attributable to all generation in the SWIS (measured in MW). The twenty forecasts represented a forecast for each of the 30-minute Trading Intervals in the 10-hour lead up to the delivery interval.[46]

The forecast data provided by AEMO represented the 2017 to 2019 period for Final Price and LSG and the 2016 to 2019 period for NSG. However, the final analysis focussed on the 2018 calendar year, which was the most recent year with a complete data set at the time of the analysis.[47] Dates with missing forecasts were removed without replacement, leading to the loss of 4% of the 2018 forecast data.

Data Treatment

In the analysis, the delivery interval was denoted by the letter N, and each half hour forecast was denoted by the number of Trading Intervals it was from the delivery interval, as set out in Table C1.

45 See http://data.wa.aemo.com.au/#balancing-summary.

46 AEMO publishes the BMO in half-hourly intervals.

47 The analysis was conducted in 2019 prior to the end of the year.

Table C1: Trading Interval Numbering Convention

Time	Delivery Interval (N)	N-1	N-2	N-3	N-4	N-5	N-6	N-7	N-8	N-9	N-10	N-11	N-12	N-13	N-14	N-15	N-16	N-17	N-18	N-19	N-20
Hour	0	0.5	1	1.5	2	2.5	3	3.5	4	4.5	5	5.5	6	6.5	7	7.5	8	8.5	9	9.5	10
Minutes	0	30	60	90	120	150	180	210	240	270	300	330	360	390	420	450	480	510	540	570	600

To demonstrate the application of this notation:

- N-1 is 0.5 hours (i.e. 30 minutes) ahead of the delivery interval, which is the BGC proposed by Perth Energy;
- N-4 is 2 hours ahead of the delivery interval and is the current BGC;
- N-5 is 2.5 hours ahead of the delivery interval and is the final forecast before the current BGC; and
- N-20 is 10 hours ahead of the delivery interval, which is Synergy's LFAS Gate Closure.

The current gate closure arrangements, including the hours ahead of delivery of the gate closure and the hours ahead of delivery of the last forecast prior to the gate closure hours, are represented in Table C2.

Table C2: Current Gate Closure Arrangements

Gate Closure Type	Gate Closure Hours Ahead of Delivery Interval		Last Forecast Hours Ahead of Delivery Interval	
BGC	2	N-4	2.5	N-5
Synergy's gate closure for the Balancing Market	4	N-8	4.5	N-9
LFAS Gate Closure	5	N-10	5.5	N-11
Synergy's LFAS Gate Closure	10	N-20	10.5	N-21[48]

48 There were no forecasts for this value. N-20 was used in the analysis as it is the closest forecast to N-21.

The potential gate closure arrangements for the 60- and 90-minute options are presented in Tables C3 and C4. For each of the 60- and 90-minute options:

- Synergy's gate closure for the Balancing Market is set 1-hour after the BGC; and
- The LFAS Gate Closure for both Synergy and IPPs is set 1-hour after Synergy's gate closure for the Balancing Market.

Table C3: Gate Closure Arrangements for the 60-minute BGC Option

Gate Closure Type	Gate Closure Hours Ahead of Delivery Interval		Last Forecast Hours Ahead of Delivery Interval	
BGC	1	N-2	1.5	N-3
Synergy's gate closure for the Balancing Market	2	N-4	2.5	N-5
LFAS Gate Closure	3	N-6	3.5	N-7
Synergy's LFAS Gate Closure	3	N-6	3.5	N-7

Table C4: Gate Closure Arrangements for the 90-minute BGC Option

Gate Closure Type	Gate Closure Hours Ahead of Delivery Interval		Last Forecast Hours Ahead of Delivery Interval	
BGC	1.5	N-3	2	N-4
Synergy's gate closure for the Balancing Market	2.5	N-5	3	N-6
LFAS Gate Closure	3.5	N-7	4	N-8
Synergy's LFAS Gate Closure	3.5	N-7	4	N-8

On the basis of Tables C1 to C4, and given the need to compare the current gate closure arrangements to the arrangements for the 90-minute BGC and 60-minute BGC options, the comparisons to be undertaken for each type of forecast are set out in Table C5.

Table C5: Assessments Undertaken for Each Type of Forecast to Compare the Current, 60- and 90-Minute BGC Options

Gate Closure Type	Comparison of gate closure options described in words	Comparison represented in notation
BGC	• Forecast for current gate closure (2 hours) compared to forecast for 90-minutes (1.5 hours) • Forecast for current gate closure compared to forecast for 60-minutes (1 hour) • Forecast for 90-minute BGC compared to forecast for 60-minute BGC	• N-5 cf. N-4 • N-5 cf. N-3 • N-4 cf. N-3
Synergy's gate closure for the Balancing Market	• Forecast for current gate closure (4 hours) compared to forecast for 150-minutes (2.5 hours) • Forecast for current gate closure compared to forecast for 120-minutes (2 hours) • Forecast for 150-minute gate closure compared to forecast for 120-minutes	• N-9 cf. N-6 • N-9 cf. N-5 • N-6 cf. N-5
LFAS Gate Closure	• Forecast for current gate closure (5 hours) compared to forecast for 210-minutes (3.5 hours) • Forecast for current gate closure compared to forecast for 180-minutes (3 hours) • Forecast for 210-minute gate closure compared to forecast for 180-minutes	• N-11 cf. N-8 • N-11 cf. N-7 • N-8 cf. N-7
Synergy's LFAS Gate Closure	• Forecast for current gate closure (10 hours) compared to forecast for 210-minutes (3.5 hours) • Forecast for current gate closure compared to forecast for 180-minutes (3 hours)	• N-20 cf. N-8 • N-20 cf. N-7

Overview of the Approach to Analysis

While AEMO provided forecast values of NSG and Final Price directly to the Rule Change Panel, forecasts for LSG had to be calculated from the information provided. Accordingly, Forecast LSG was calculated by subtracting each forecast of NSG from the corresponding forecast of Total Generation for each of the 20 forecasts, for each delivery interval.

Errors in forecasting were calculated for each type of forecast by subtracting each of the 20 forecast values (i.e. one for each 30-minute Trading Interval leading up to the delivery interval) from the actual value in the delivery interval (i.e. forecast error = forecast – actual). For example, the 20 forecasts of LSG were each compared to the actual value of LSG recorded in the Balancing summary for that Trading Interval, to determine the error in each forecast.

The absolute values of each distribution of errors in forecast were calculated. The Mean Absolute Error (**MAE**) was then calculated for each of the 20 forecasts by taking the absolute value of the forecast errors in each calendar year and averaging them for each forecast ahead of the Trading Interval.

The MAE distributions were plotted to illustrate changes in accuracy over the years and were used to select the 2018 calendar year for analysis. The 2018 calendar year was selected for closer analysis of the actual error distributions, as the MAE distributions for 2018 were consistent with other years and 2018 was the most recent year with a full calendar year of data for each forecast type at the time of the analysis.

The comparisons outlined in Table C5 were then made to see whether there were differences in accuracy between the forecasts for each of the differing BGC options (i.e. at 2 hours, 90 minutes and 60 minutes).

To do this, the difference in absolute error distributions were calculated by subtracting the absolute values of the errors of the forecasts for one gate closure option from the absolute values of the errors of the forecasts for a shorter gate closure option.

A bootstrapping technique was then used to produce bootstrap distributions of the medians of the difference in absolute error distributions (see below). A bootstrap percentile method was used to calculate 99% confidence intervals for the medians and determine whether the differences between forecasts for each gate closure option were statistically significant.

The output from these analyses are summarised in the sections below.

Description of Errors

Mean Absolute Errors in Forecasting

Distributions of the MAEs in forecasting are presented below for each type of forecast. MAE was used because positive and negative errors, due to over and under forecasting, will cancel out if the mean error is calculated. For example, if one error is 6 MW and another error is -6 MW, the average error is zero. This does not show the magnitude and range of errors, which is actually 6 MW in both directions.[49]

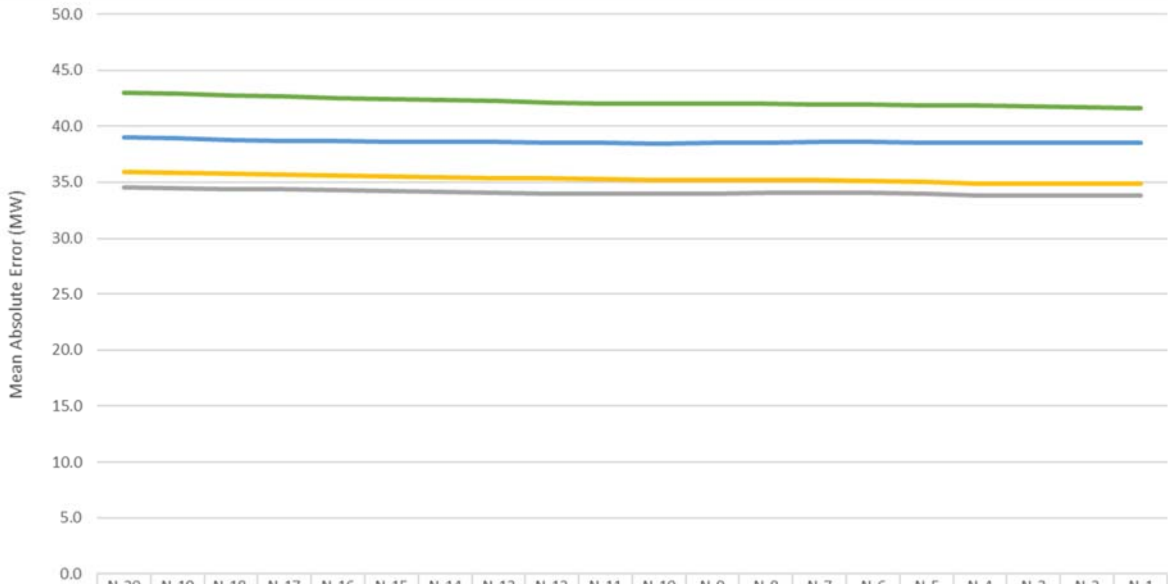
[49] The Mean Absolute Percent Error (**MAPE**) was not used as it can be misleading because, if prices are close to zero, MAPE values can be large regardless of the actual absolute errors. If prices spike, resulting MAPE values are small. MAPE for negative prices are difficult to interpret.

Figure C1 shows the MAEs in forecast NSG at each time of forecast, for each year from 2016 to 2019. Figure C1 shows that there was no dramatic trend toward an increase in accuracy closer to real time (i.e. the MAE curves are horizontal with a slight leftward downward slope).

Up until June 2019, Market Participants were unable to update their Balancing Submissions following the BGC, so the N-4 to N-1 forecasts are the same.

However, Figure C1 shows that from 2016 to 2018, the forecasts of NSG were trending toward being increasingly better (indicated by the reduction in MAE from year to year) but the MAE for 2019 was inconsistent with this trend, producing the highest MAEs overall, possibly due to the entrance of the Badgingarra wind farm to the market.

Figure C1: Mean Absolute Error in Forecasts of NSG from 2016 to 2019

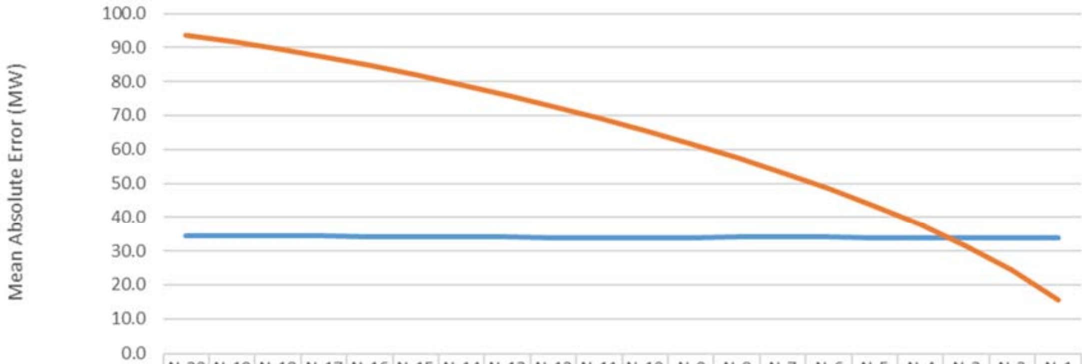


	N-20	N-19	N-18	N-17	N-16	N-15	N-14	N-13	N-12	N-11	N-10	N-9	N-8	N-7	N-6	N-5	N-4	N-3	N-2	N-1
2016	39.0	38.9	38.8	38.7	38.7	38.6	38.6	38.6	38.5	38.5	38.4	38.5	38.5	38.6	38.6	38.5	38.5	38.5	38.5	38.5
2017	35.9	35.9	35.8	35.7	35.6	35.5	35.5	35.4	35.3	35.3	35.2	35.2	35.2	35.2	35.1	35.1	34.9	34.9	34.9	34.9
2018	34.5	34.5	34.4	34.4	34.3	34.2	34.1	34.1	34.0	34.0	34.0	34.0	34.0	34.1	34.0	34.0	33.9	33.9	33.9	33.9
2019	43.0	42.9	42.8	42.6	42.5	42.4	42.3	42.3	42.1	42.0	42.0	42.0	42.0	41.9	41.9	41.9	41.8	41.8	41.7	41.6

Time of Forecast

Figure C2 presents the MAEs of the Persistence NSG forecasts for 2018, and includes the MAEs of the 2018 NSG forecasts for comparison. Figure C2 shows that there is a trend toward greater accuracy closer to real time in the Persistence NSG forecast (with an increase of approximately 78 MW between N-20 and N-1). However, the Persistence NSG forecasts were only more accurate than NSG forecasts between N-3 and N-1 (i.e. after the current BGC, when participants were unable to update their Balancing Submissions in most of the review period).

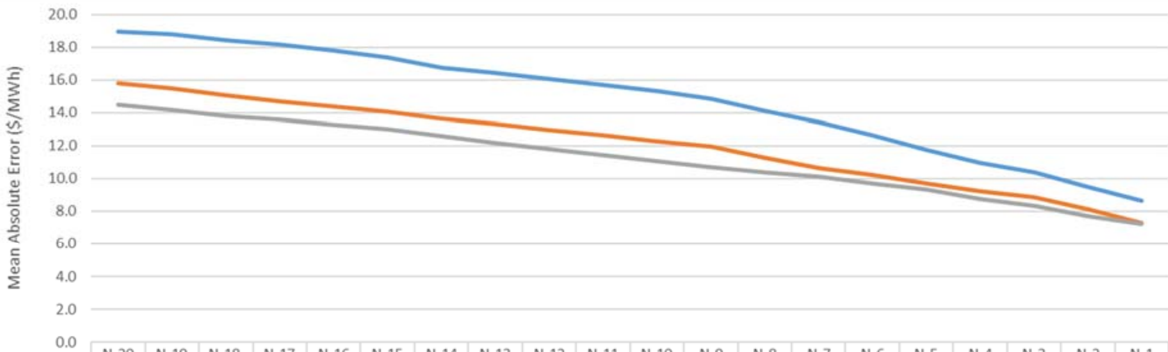
Figure C2: Mean Absolute Error in Persistence Forecasts of NSG for 2018



	N-20	N-19	N-18	N-17	N-16	N-15	N-14	N-13	N-12	N-11	N-10	N-9	N-8	N-7	N-6	N-5	N-4	N-3	N-2	N-1
NSG Forecast 2018	34.5	34.5	34.4	34.4	34.3	34.2	34.1	34.1	34.0	34.0	34.0	34.0	34.0	34.1	34.0	34.0	33.9	33.9	33.9	33.9
Persistence NSG 2018	93.6	91.7	89.6	87.2	84.7	81.9	79.0	75.9	72.6	69.2	65.5	61.5	57.5	53.1	48.4	43.4	37.8	31.5	24.3	15.5

Figure C3 presents the MAEs of the Final Price forecasts for 2017 to 2019. Figure C3 shows a trend toward greater accuracy closer to real time. However, the increase in accuracy of the forecasts closer to real time appears quite small (for example, the difference between the N-20 and the N-1 forecasts is only $8.5/MWh in the 2018 calendar year).

Figure C3: Mean Absolute Error in Final Price Forecasts from 2017 to 2019

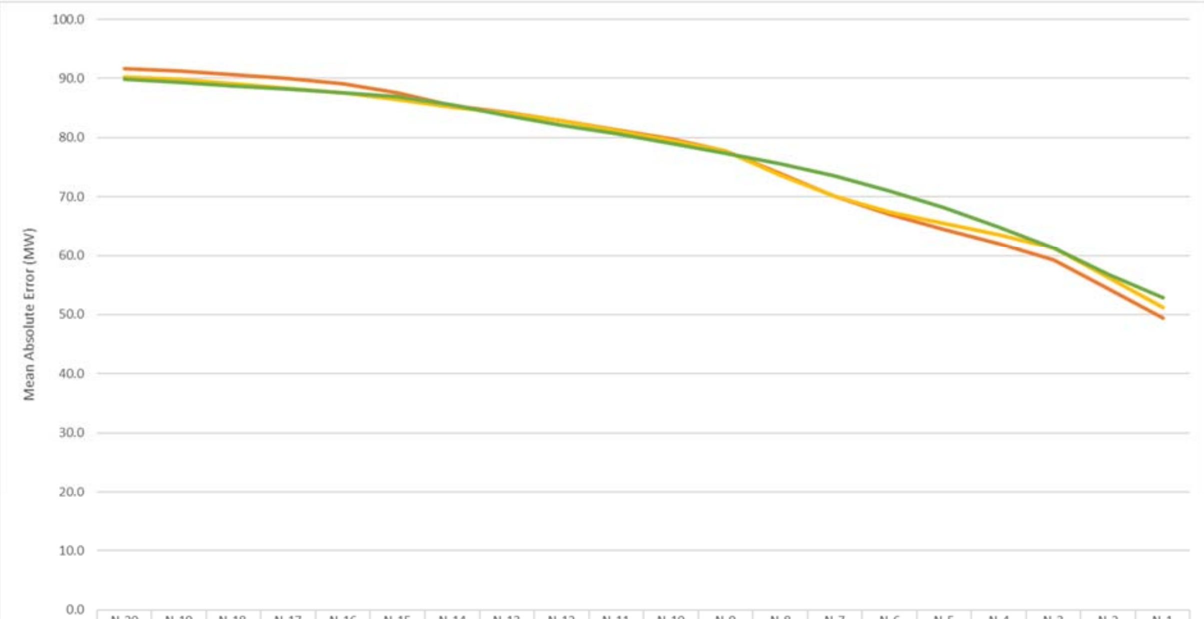


	N-20	N-19	N-18	N-17	N-16	N-15	N-14	N-13	N-12	N-11	N-10	N-9	N-8	N-7	N-6	N-5	N-4	N-3	N-2	N-1
2017	19.0	18.8	18.4	18.1	17.8	17.4	16.8	16.4	16.1	15.7	15.4	14.9	14.1	13.4	12.7	11.8	10.9	10.4	9.5	8.6
2018	15.8	15.5	15.0	14.7	14.4	14.1	13.6	13.3	13.0	12.7	12.3	12.0	11.3	10.7	10.2	9.7	9.2	8.9	8.1	7.3
2019	14.5	14.1	13.8	13.6	13.3	13.0	12.6	12.1	11.8	11.5	11.1	10.7	10.4	10.1	9.7	9.3	8.8	8.3	7.7	7.2

Time of Forecast

Figure C4 presents the MAEs of the LSG forecasts for 2017 to 2019. There were minimial differences in the MAEs observed across the years. The data for 2019 only represented up to August of that year, which may explain the slight difference in forecasting between the years across the N-8 to N-4 forecasts. There was a trend toward greater accuracy closer to real time, with an increase in accuracy of approximately 40 MW between the N-20 and N-1 forecasts.

Figure C4: Mean Absolute Error in LSG Forecasts from 2017 to 2019



	N-20	N-19	N-18	N-17	N-16	N-15	N-14	N-13	N-12	N-11	N-10	N-9	N-8	N-7	N-6	N-5	N-4	N-3	N-2	N-1
2017	91.7	91.2	90.7	90.0	89.1	87.5	85.5	84.3	82.9	81.4	79.8	77.8	73.9	70.1	67.0	64.4	62.0	59.2	54.4	49.5
2018	90.2	89.8	89.2	88.4	87.5	86.4	85.1	84.1	82.8	81.2	79.5	77.7	73.7	70.0	67.4	65.5	63.5	61.2	56.3	51.2
2019	89.9	89.4	88.8	88.2	87.6	87.0	85.5	83.7	82.1	80.6	79.1	77.4	75.6	73.5	71.0	68.1	64.9	61.2	56.8	52.8

Actual Errors in Forecasting in the 2018 Calendar Year

Boxplots of the error distributions for all forecasts from N-1 through N-20 for each type of forecast in 2018 are presented below to illustrate the pattern of errors found in the data.

Figure C5 shows errors in forecast NSG. The error distributions were largely symmetrical, except for a set of extreme outliers in the top of the figure. The symmetrical nature of the forecasts indicates that they changed little over time, which is to be expected for the N-1 to N-4 forecasts, in particular, as Market Participants were unable to change their Balancing Submissions after BGC.

Investigation of the outliers showed that they spanned the period 2-3 May 2018 (N-1 at 8:30 PM and N-20 at 6:00 AM). A Dispatch Advisory issued at 1:04 AM on 2 May 2018 (withdrawn at 6:36 AM) noted that Western Power experienced IT issues impacting some of AEMO's Market Systems and the matter was being investigated. A Market Systems Planned Outage to the WEMS Production Environment commenced at 7:40 PM on 2 May 2018 and was complete by 8:24 PM.

Figure C5: Boxplots of 2018 Errors in Forcasts of NSG

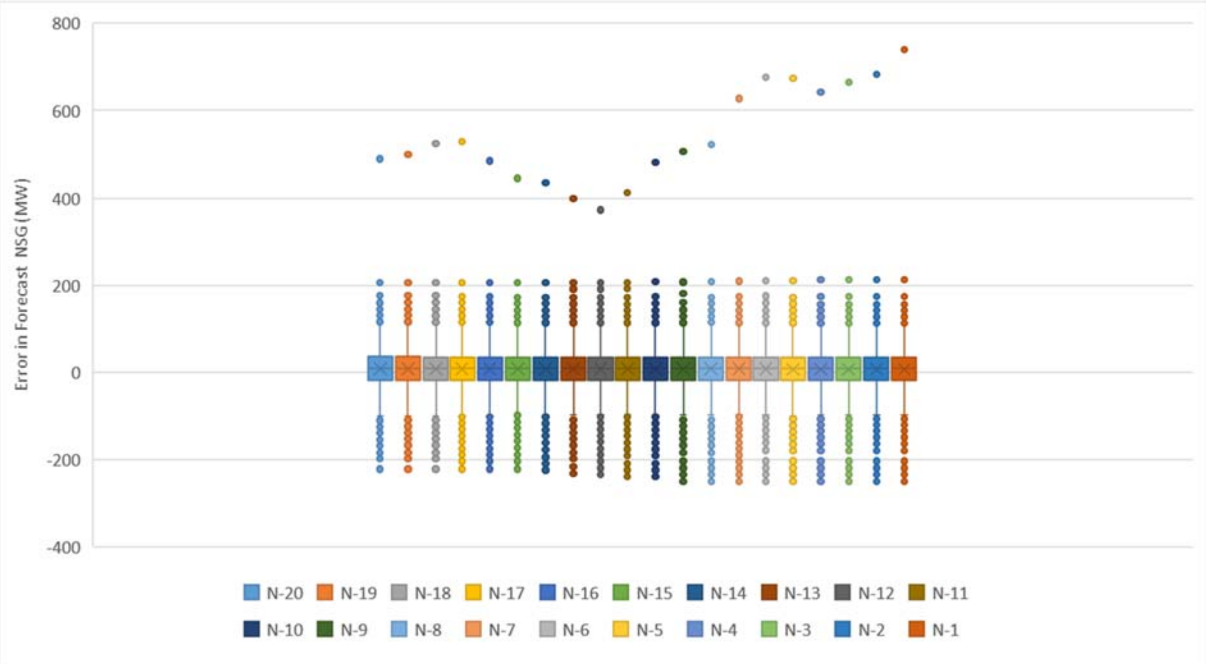


Figure C6 presents boxplots of the errors in Persistence NSG forecasts for 2018. The distributions of errors were symmetric and the forecasts trended toward being increasingly accurate (and therefore leptokurtic) the closer they were to real time. This is consistent with the nature of the data (i.e. we would expect to find that a wind forecast based on the previous Trading Interval is more accurate closer to the delivery interval, than if the forecast was made a number of hours earlier).

Figure C6: Boxplots of 2018 Errors in Persistence Forcasts of NSG

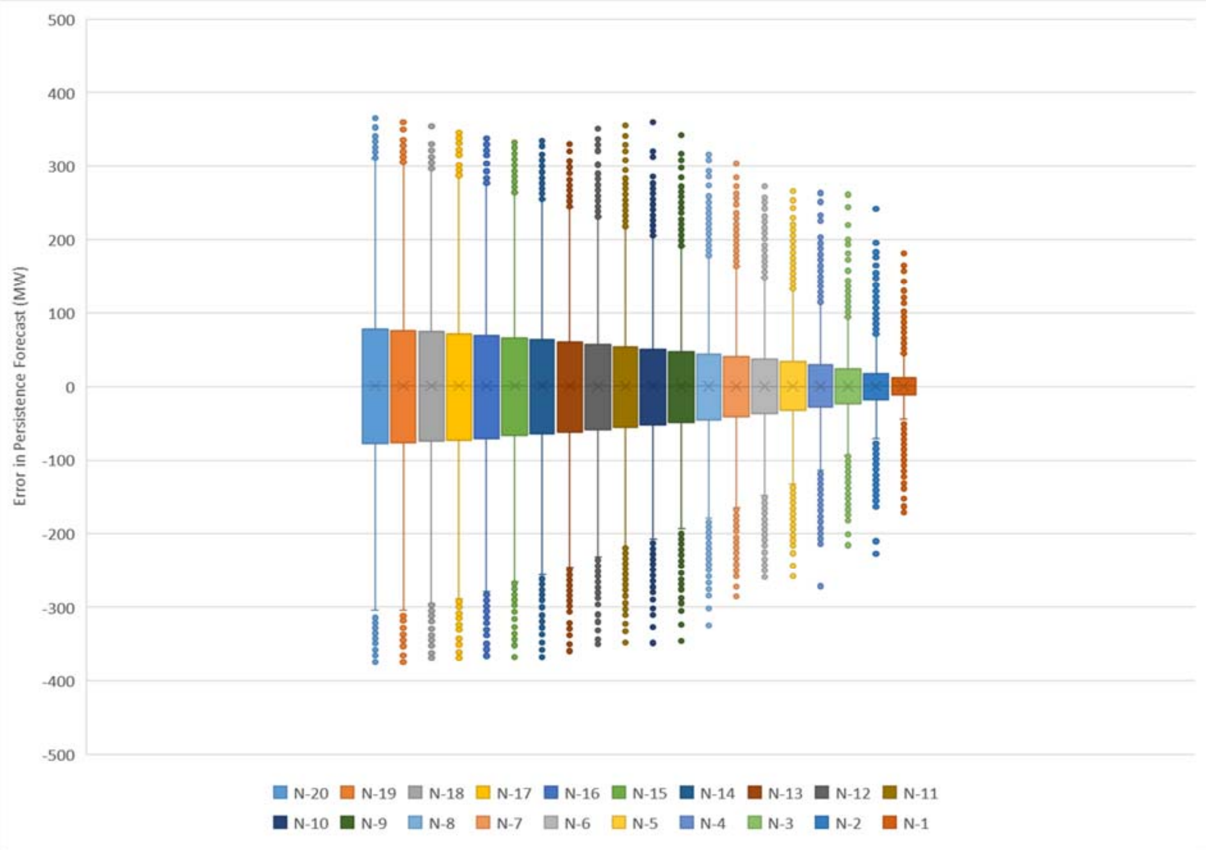


Figure C7 shows the errors in Final Price forecasts in 2018. The distributions of the errors for each forecast were increasingly leptokurtic (more tightly packed around the mean) as they got closer to real time, with kurtosis ranging from 8.33 at N-20 to 19.35 at N-1. This is to be expected given the nature of the data.

Figure C7: Boxplots of 2018 Errors in Forecast Final Price

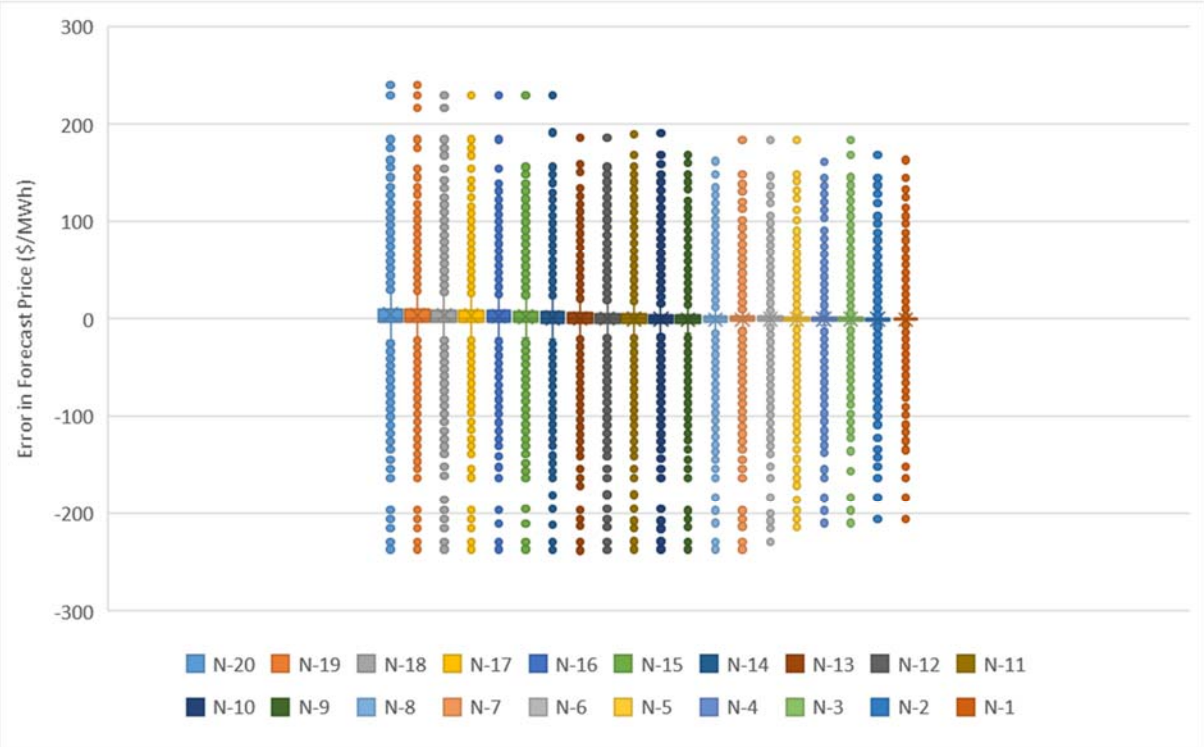
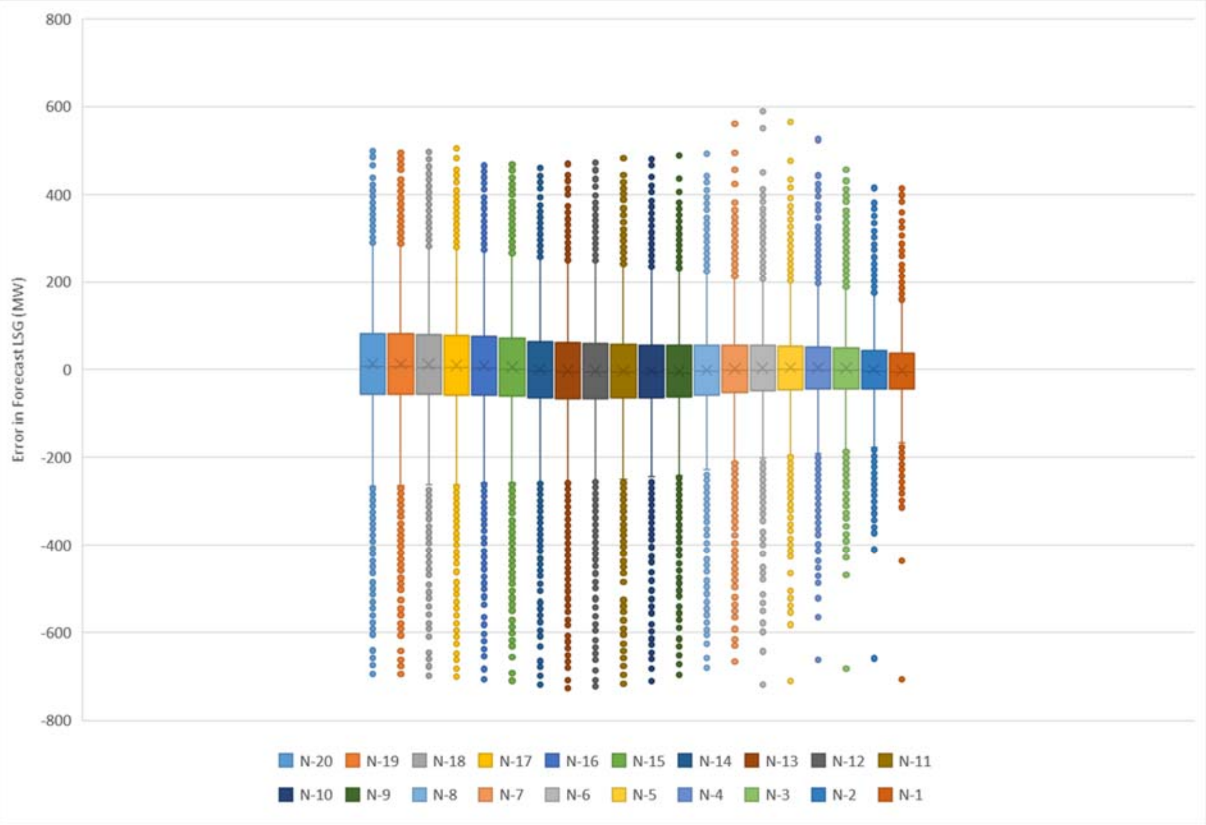


Figure C8 shows errors in forecast LSG. The scattering of outliers between N-7 and N-1 corresponded to system outages.[50] Extreme errors in under forecasting tended to have a larger range than extreme errors in over forecasting. However, all error distributions (i.e. for each forecast) were found to be normally distributed, as indicated by skew and kurtosis values between 3 and -3.

Figure C8: Boxplots of 2019 Errors in Forcast LSG



Bootstrapping Analysis and Interpretation

Difference in absolute error distributions were calculated for the 2018 data by subtracting the absolute errors of the forecasts at one gate closure (e.g. at N-5, which is the time of the last forecast for a two-hour gate closure) from the absolute errors of the forecasts at a shorter gate closure (e.g. N-4, which is the time of the last forecast for a 90-minute gate closure).

A bootstrapping technique was then applied to the difference in absolute error distributions to determine whether the differences between forecasts for each gate closure option were statistically significant.

In the current analysis, 1,000 random samples were taken from each of the difference in absolute error distributions and were used to produce 'bootstrap' distributions for the median of each difference in absolute error distribution for forecast LSG and Persistence NSG.

Table C6 presents descriptive statistics for the difference in absolute error distributions for Persistence NSG forecasts. Comparisons further from real time are not presented as it would not make sense to replace more accurate forecasts of NSG (i.e. at forecasts of greater than N-3) with less accurate persistence forecasts at these times.

50 Analyses were conducted with and without the outliers and produced similar results.

Table C6: Descriptive Statistics for the Difference in Absolute Error Distributions for the Persistence NSG Forecasts (MW)

Comparison	Mean	SE Mean	Standard Deviation	Median	Min	Max	Skew	Kurtosis
N-5 minus N-4	5.596	0.151	19.130	3.858	-129.180	170.879	0.51	4.70
N-4 minus N-3	6.291	0.148	18.736	4.338	-130.949	165.146	0.67	5.20
N-5 minus N-3	11.888	0.216	27.358	8.356	-182.995	242.288	0.64	2.96

Table C7 presents descriptive statistics for the difference in absolute error distributions for LSG forecasts for all comparisons in Table C5.

Table C7: Descriptive Statistics for the Difference in Absolute Error Distributions for the LSG Forecasts (MW)

Comparison	Mean	SE Mean	Standard Deviation	Median	Min	Max	Skew	Kurtosis
N-5 minus N-4	1.973	0.185	23.848	1.338	-176.341	153.509	0.13	4.41
N-4 minus N-3	2.300	0.185	23.833	1.035	-228.895	159.853	0.22	5.75
N-5 minus N-3	4.273	0.272	35.096	2.576	-316.968	263.220	0.38	4.51
N-9 minus N-6	10.466	0.368	47.455	7.300	-238.620	535.577	0.28	3.34
N-6 minus N-5	1.963	0.180	23.263	1.420	-171.545	168.899	0.05	4.10
N-11 minus N-8	7.545	0.264	33.998	4.741	-518.029	386.697	0.40	8.50
N-8 minus N-7	3.792	0.185	23.834	2.605	-153.922	535.149	0.78	18.08
N-20 minus N-8	16.552	0.427	55.111	10.315	-534.152	428.543	0.82	3.54
N-9 minus N-5	12.429	0.442	57.064	8.546	-283.430	520.733	0.28	2.95
N-11 minus N-7	11.337	0.344	44.323	7.261	-247.102	403.942	0.51	3.50
N-20 minus N-7	20.343	0.470	60.642	12.765	-260.171	454205	0.83	2.60

The medians of the difference in absolute error distributions were used as the main parameter in the bootstrapping analysis rather than the means of these distributions, as the distributions had outliers and were highly leptokurtic, particularly for data closer to real time, which is to be expected given the nature of the data.

The Bootstrap percentile method was used to calculate 99% confidence intervals for the medians, and if the confidence interval:

- included a median of 0, then the null hypothesis was accepted (i.e. there is no statistically significant difference between the absolute values of the errors in forecasts between the gate closure options); and

- did not include a median of 0, then the alternative hypothesis was accepted (i.e. there is a statistically significant difference between the absolute values of the errors in forecasts between the gate closure options).

In each case, the 99% confidence intervals from the bootstrapping analysis on the medians of the difference in absolute error distributions for the Persistence NSG forecasts did not include a median of 0 MW, as shown in Table C8.

Table C8: Upper and Lower Bounds of the 99% Confidence Intervals for the Medians of the Difference in Abolute Error Distributions for the Persistence NSG Forecasts (MW)

Comparison	Median	Lower Bound	Upper Bound
N-5 minus N-4	3.855	3.525	4.167
N-5 minus N-3	8.363	7.793	8.846
N-4 minus N-3	4.327	4.024	4.696

It can therefore be concluded that there is a statistically significant difference between the absolute values of the errors in the Persistence NSG forecasts for the different BGC options compared in Table C8. However, as noted above in Figure C2, the persistence forecast only becomes more accurate than the NSG forecast between N-4 and N-3, which negates the utility of the persistence forecast.

Similarly, in each case, the 99% confidence intervals for the medians of the difference in absolute error distributions for forecast LSG did not include a median of 0 MW, as presented in Table C9.

Table C9: Upper and Lower Bounds of the 99% Confidence Intervals for the Medians of the Difference in Abolute Error Distributions for the LSG Forecasts (MW)

Comparison	Median	Lower Bound	Upper Bound
BGC			
N-5 minus N-4	1.330	1.000	1.639
N-5 minus N-3	2.576	2.098	3.115
N-4 minus N-3	1.039	0.707	1.383
Synergy's gate closure for the Balancing Market			
N-9 minus N-6	7.298	6.489	8.026
N-9 minus N-5	8.547	7.522	9.601
N-6 minus N-5	1.405	1.099	1.753

Comparison	Median	Lower Bound	Upper Bound
LFAS Gate Closure			
N-11 minus N-8	4.732	4.125	5.359
N-11 minus N-7	7.229	6.537	7.924
N-8 minus N-7	2.605	2.279	2.999
Synergy's LFAS Gate Closure			
N-20 minus N-8	10.315	9.278	11.350
N-20 minus N-7	12.768	11.828	13.700

It can therefore be concluded that there is a statistically significant difference between the absolute values of the errors in the LSG forecasts for the different gate closure options assessed in this analysis.

Bootstrap analyses were not undertaken for forecast NSG and forecast Final Price, as the medians of the difference in absolute error distributions were 0 MW for each of these types of forecasts. That is, there was no difference between the absolute errors in forecast between the gate closure options for these types of forecasts, which was to be expected given the pattern of errors and the nature of the data.

Assessment of the 30-minute BGC Option

While the Rule Change Panel has rejected the option for a 30-minute BGC because it is infeasible, given the timeframe of System Management's processes and the start-up times of gas units in the WEM, for completeness, a bootstrapping analysis was undertaken to determine whether a significant increase in accuracy occurs in comparison to the current BGC. The outcomes of these analyses are provided in Tables C10 and C11.

Table C10: Descriptive Statistics for the Difference in Absolute Error Distributions Between the N-5 and N-2 LSG Forecasts (MW)

Comparison	Mean	SE Mean	Standard Deviation	Median	Min	Max	Skew	Kurtosis
N-5 minus N-2	9.176	0.323	41.720	4.617	-274.238	333.480	0.91	4.88

Table C11: Upper and Lower Bounds of the 99% Confidence Intervals for the Medians of the Difference in Abolute Error Distributions Between the N-5 and N-2 LSG Forecasts (MW)

Comparison	Median	Lower Bound	Upper Bound
N-5 minus N-2	4.605	4.072	5.287

The 99% confidence interval from the bootstrapping analysis on the median of the difference in absolute error distributions between the N-5 and N-2 LSG forecasts did not include a median of 0 MW, as shown in Table C11.

It can therefore be concluded that there is a statistically significant difference between the absolute values of the errors in the LSG forecasts for the current and 30-minute BGC option.