Government of Western Australia
Department of Finance
Public Utilities Office

Market Power Mitigation Mechanisms for the Wholesale Electricity Market

Information Paper

Department of Finance | Public Utilities Office
October 2016

TRIM: 01921752

Table of Contents

1. Introduction

The Electricity Market Review released the *Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms* (Final Report) on 28 July 2016. The Final Report indicated that the Electricity Market Review would undertake a broad review of market power mitigation measures in the energy and ancillary services markets. This review would include consideration of bidding restrictions, price caps and the Short Term Energy Market (STEM), and that a report on these matters would be published in the second half of 2016.

A review of market power mitigation measures was suggested in several submissions made by market participants in response to the release of the *Position Paper: Design Recommendations for the Wholesale Energy and Ancillary Market Reforms* (Position Paper), published for stakeholder consultation on 14 March 2016. The Position Paper proposed that no fundamental changes to the current market power mitigation measures were required, but indicated that some refinements may be needed to reflect the design features of the proposed new market arrangements and also provide more clarity to participants about their obligations. The new markets may bring changes that would influence the choice of some input assumptions for price limit analysis. (For example, the proposed reductions to gate closure and dispatch interval times may make it imperative to change the criteria for selecting historic dispatch cycles for analysis.)

The Position Paper also noted that while the STEM does not provide long forward price signals (given that it is a day-ahead market), it makes energy available at reasonable prices, has relatively low transaction costs, and incorporates market power mitigation measures (including the mandatory offering of spare certified capacity) that alleviates concerns about the competitiveness of the market structure in the South West Interconnected System.

The Position Paper indicated the Electricity Market Review had not found an alternative forward market design able to provide all these features under the current market structure, and that consequently it was proposed there is an insufficient case for changing the STEM at this time, provided the cost to retain the STEM under the new market arrangements is not excessive.

However, on account of the STEM's mandatory offer requirements and associated cost-based bidding obligations, the Electricity Market Review stated in the Final Report it would reserve its decision on the future role of the STEM until the market power mitigation review had been completed.

This Information Paper outlines at a high level the findings and recommendations of the review of market power mitigation measures. It also provides an overview of the Electricity Market Review's response to these recommendations and how matters relating to market power mitigation will be addressed within the implementation work program for the Energy Market Operations and Processes project.

2. The Brattle Group Report

The Brattle Group was appointed to conduct the review and its report, entitled *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia* (Brattle Group Report), is attached.

The Brattle Group reviewed mechanisms for the mitigation of market power that could be applied in the South West Interconnected System. The review was required to identify potential costs and benefits and the practicality of alternatives to the current mechanism for market power mitigation, and also consider the future role of the STEM.

The findings and recommendations of the Brattle Group Report agree with the Electricity Market Review's position, expressed earlier in the Position Paper: that the current approach to market power mitigation in the Wholesale Electricity Market is effective and should be retained, albeit with improvements, dot pointed over the page. Importantly, the Brattle Group expressed support on the need for, and use of, short run marginal cost (SRMC) as a bidding restriction in the Wholesale Electricity Market, albeit with some refinements. This is because in the Wholesale Electricity Market, where a capacity mechanism complements the energy market, competitive outcomes are achieved if energy offers reflect suppliers' SRMC. More specifically, the Brattle Group concludes the primary objective of market power mitigation for the Wholesale Electricity Market is ensuring that suppliers' with instantaneous market power make energy offers that are SRMC-based.

The Brattle Group did not support relying on general competition law to achieve this outcome. This is because, as the Reserve Capacity Mechanism provides for fixed cost recovery, it is reasonable that regulatory arrangements target an outcome that ensures generator offers are SRMC based (where these generators hold instantaneous market power). This contrasts with the National Electricity Market (which relies on general competition law to mitigate market power) where there is no capacity mechanism and where, therefore, it is not desirable to target SRMC-based prices.

The Brattle Group clarified that a behavioural market power mitigation mechanism (such as ex-post monitoring of SRMC bidding obligations) would still be necessary in an environment of reduced market concentration to discipline behaviour under temporal conditions when the market is susceptible to market power. Even moderately sized generators can have market power during peak demand periods when supplies become limited. Market power can become especially acute locally when transmission constraints protect local generators from competitors.

The Brattle Group also highlighted the practical considerations associated with the use of ex-post market power mitigation arrangements given that a form of judgement is required, compared to the more formulaic approach that is used for ex-ante measures.[1]

[1] A particular consideration relates to the application of the "reasonableness standard" – see pages 10, 11 and 14 of the Brattle Group Report for the more detailed discussion of these matters.

The Electricity Market Review agrees with the Brattle Group's views on the primary objective of market power mitigation for the Wholesale Electricity Market. It is the Electricity Market Review's view that shifting the regulatory focus away from an SRMC-based generator offer requirement would result in inefficiencies[2] and mute the economic signal to bring any excess capacity into balance.

The Brattle Group assessed several alternatives[3] for the mitigation of market power against its assessment criteria (that is, the ability to achieve SRMC-based offers, avoidance of false positive interventions and marked false negatives, cost effectiveness, transparency and timeliness)[4] and concluded that an ex-post mitigation approach (as currently occurs) best meets all of these criteria[5]. Ex-post mitigation relies on after-the-fact mitigation when all the information is available to the regulator and is enforced by threat of punitive sanctions, such as financial penalties and prescriptive orders.

One of the alternatives assessed by the Brattle Group that did not expressly rely on SRMC-based offer requirements was mandated long-term forward sales. This option targets diminishing dominant suppliers' incentives or abilities to exercise market power by reducing their market share, such that the market shifts towards the competitive norm. It requires dominant suppliers to contractually sell through power purchase agreement auction type mechanisms some (or all) of their capacity on a forward basis.

The Brattle Group assessed this alternative to have merit. However, given the complexities in determining the sales quantities, contract terms and auction processes, and the likely lengthy implementation period involved,[6] it concluded this alternative was more suited to the longer term and would not be feasible to implement by the start of the new market in July 2018. The Brattle Group also concluded that forward contracts could not make the market competitive in all circumstances, and so a behavioural market power mitigation mechanism (namely, ex-post monitoring of SRMC-based offer requirements) would still be needed to address the inevitable temporal conditions where the electricity market remains susceptible to exercises of market power.

The Electricity Market Review agrees with the Brattle Group's assessment that ex-post mitigation of market power best satisfies the evaluation criteria and therefore should be retained.

The Brattle Group made several recommendations for improving the current approach to market power mitigation in the Wholesale Electricity Market. These comprise:

- several amendments to the Wholesale Electricity Market Rules to better define prohibited pricing behaviour;
- development of a workable definition of SRMC;

[2] The Brattle Group Report concludes that SRMC-based offers promote operational efficiency through lowest cost dispatch and investment in the economically efficient mix of technologies, while the Reserve Capacity Mechanism provides for additional fixed cost recovery in order to attract and retain sufficient capacity required to meet reliability objectives.

[3] See pages 17-30 of the Brattle Group Report for detailed discussion and assessment of all alternatives.

[4] See page iii of the Brattle Group Report - an expanded discussion of each criterion is provided from page 6 of the report.

[5] The full discussion of how the ex-post mitigation approach meets the evaluation criteria is set out on page 22 of the Brattle Group Report.

[6] The Brattle Group suggests this could take several years and noted that such a process in Alberta Canada resulted in a series of auctions held between 2000 and 2006.

- consideration of whether or not to increase the market offer price caps;
- continuation of the use of screening analyses as part of a behavioural market power mitigation approach focussed on ex-post observed deviations from SRMC[7];
- mitigation of the spot (balancing) market and the STEM consistent with the proposed revisions; and
- application of essentially the same approach to mitigating market power in the ancillary service markets.

The first two recommendations reflect the Brattle Group's view that the lack of definitional clarity in the provisions governing pricing behaviour and offer formation increases market participants' risks and potentially increases regulatory costs.

The Electricity Market Review agrees that the definitions of prohibited pricing behaviour and SRMC need to be clarified to reduce uncertainty about their application. SRMC review processes must also accommodate the fact that bids are made ex ante with an imperfect understanding of future market conditions, while reviewing bodies will have the ex post benefit of historic data (perfect hindsight). The information known to participants at the time of bidding must be the basis of any review process. Given the inherent complexities of these concepts and their importance to market participants, a more extensive analysis and public consultation process is warranted before any final decisions are made.

For this reason, the Electricity Market Review does not recommend any specific changes or clarifications to the SRMC bidding provisions at this time, but instead proposes to conduct a more extensive study to clarify the SRMC bidding obligations and develop supporting SRMC bidding guidelines as part of the implementation work program for the Energy Market Operations and Processes project. These guidelines will be developed in recognition of the difficulties associated with the information asymmetry between an electricity generator making supply offers in real time, versus the ex-post analysis of the reasonableness of these offers by a regulator.

The Brattle Group's third recommendation relates to the setting of offer price caps. The offer price caps for the energy market (the energy price limits) are reviewed every year by the Australian Energy Market Operator, with any changes subject to approval by the Economic Regulation Authority.

Since market start, the energy price limits have been determined using a probabilistic method that delivers a price expected to cover the short run average costs of the highest cost 40 MW open-cycle gas turbine in the South West Interconnected System, for at least 80 per cent of dispatch cycles between 0.5 and six hours in length. The method is not explicitly prescribed in the Wholesale Electricity Market Rules but is broadly supported by stakeholders. To date, no market participant has ever presented evidence to an energy price limits review to show that the energy price limits were preventing it from recovering its short run costs.

The Brattle Group recommended consideration of an increase to the offer caps to cover a greater percentage of dispatch cycles (that is, more than 80 per cent), so that generators

[7] The Brattle Group Report provides discussion of the use of screening analysis to identify when market power exists (such as use of the pivotal supplier test) and when supplier offers exceed SRMC (through the comparison of actual offers to benchmark offers) - see page 15 and Appendix A.

could more reliably recover their short run costs. The Electricity Market Review agrees that under the new market conditions, and in particular with the introduction of five-minute dispatch intervals, some adjustments may be required to the price determination method to ensure the energy price limits continue to recover generators' short run costs in most cases.

The Brattle Group's recommendation is consistent with the Electricity Market Review's proposal[8] that the Australian Energy Market Operator and the Economic Regulation Authority take the potential effects of the proposed market design changes into consideration during future reviews of the energy price limits. It should be remembered that:

- it would be impractical and inefficient to design the energy price limits to target the full recovery of short run costs for all generators under all circumstances; and
- without historical data on dispatch and pricing outcomes under the new market conditions it may be difficult to demonstrate why an increase in the energy price limits is necessary and in the long term interest of consumers.

While no changes are proposed to the current determination arrangements (where the energy price limits are proposed by the Australian Energy Market Operator and approved by the Economic Regulation Authority), there may be merit in more clearly documenting the cost-recovery goal for the energy price limits[9] in the Wholesale Electricity Market Rules. The Electricity Market Review proposes to consult with stakeholders as part of the Energy Market Operations and Processes implementation work program on:

- whether the cost-recovery goal for the energy price limits should be documented more explicitly in the Wholesale Electricity Market Rules; and
- if so, whether any changes to the cost recovery goal used in recent energy price limit determinations are warranted prior to the start of the new spot market.

While the fourth and fifth recommendations (continuation of the use of screens for ex-post monitoring and the application of this mechanism to both the STEM and spot markets) are to some extent dependent on the acceptance of earlier recommendations, the Electricity Market Review supports the continued use of ex-post monitoring of SRMC bidding obligations using screens in both energy markets.[10]

The Brattle Group's final recommendation was to apply essentially the same approach to mitigating market power in the ancillary service markets. As the new ancillary service markets will also be vulnerable to the abuse of market power, the Electricity Market Review agrees restrictions will need to be placed on participant offers and some form of ex-post monitoring will be necessary. However, participation in the ancillary service markets will not be mandatory (except for Synergy) and offer restrictions may need to account for the recovery of "long run" costs incurred specifically to provide the service, where these costs are not recovered through the Reserve Capacity Mechanism.

[8] Refer to the Position Paper, page 65.

[9] Currently, this "goal" is that the price limit would allow the highest cost 40 MW open cycle gas turbine in the South West Interconnected System to recover its short run costs for a least 80 per cent of dispatch cycles between 0.5 and 6 hours in length.

[10] As noted by The Brattle Group setting these screens is a relatively resource intensive exercise in considering the risks and costs of both under-identifying and over-identifying a supplier's ability and incentive to exercise market power.

Further analysis and consultation will be needed to determine what costs should be included in an ancillary service market offer and how offer price caps should be determined for these markets.

The Brattle Group analysed several options for the future of the STEM, including retention, amendment, replacement and removal. The primary evaluation criterion[11] for this assessment was the ability to maintain a liquid and competitive day-ahead market.

The Brattle Group recommended retaining the STEM within the new market design. This reflects the Brattle Group's conclusions that:

- the STEM, based on a mandatory SRMC-based offer requirement, is an efficient mechanism to provide liquid low cost day ahead hedging opportunities needed by participants; and
- rolling the STEM into the National Electricity Market systems has low development risk, and is low cost based on advice from the Australian Energy Market Operator.

The Electricity Market Review agrees with the Brattle Group's recommendation and will request the Australian Energy Market Operator to include the STEM with the modifications originally proposed in the Position Paper,[12] in its development of the new market systems.

[11] Secondary criteria were the costs, implementation complication and risk, and timeliness (in operation by 1 July 2018).

[12] These include removing the redundant Resource Plan requirement and extending the STEM daily submission window by one hour (to 10:50 am).

3. Energy Market Operations and Processes implementation work program

The Electricity Market Review has started work on the implementation phase of the Energy Market Operations and Processes project. The work program includes the following elements that relate to market power mitigation and the recommendations and concerns set out in the Brattle Group Report.

3.1 SRMC bidding restrictions

1. Consideration of how to better define prohibited pricing behaviour to clarify what are deemed as unacceptable bidding practices. This involves clarification of the expressions “when such behaviour relates to market power” and “short run marginal cost”. The options to be considered will include, but not be limited to, the following recommendations:
   - removing what the Brattle Group refers to as the “intent” element of the definition, by replacing the phrase “when such behaviour relates to market power” with “when the supplier has market power and their behaviour raises prices above competitive levels”;
   - defining market power as “the ability to profitably raise the market price”; and
   - defining SRMC as “all costs that a supplier without market power would include in forming its profit-maximising offer”.
2. Development of amendments to the Wholesale Electricity Market Rules to require the publication and periodic review of procedural guidelines for interpretation of the SRMC provisions (SRMC bidding guidelines).[13]
3. Development of initial SRMC bidding guidelines in consultation with the Economic Regulation Authority, the Australian Energy Market Operator and other stakeholders.[14]
4. Consideration of what costs a participant with market power should be able to include in its ancillary service market offers, and extension of the SRMC bidding guidelines (or the development of separate bidding guidelines) for the ancillary service markets.

3.2 Price caps

1. Consideration of what price caps should apply in the ancillary service markets, for both offers and final prices (as the co-optimisation process can result in final prices exceeding the offer caps).[15]
2. Consideration of whether the cost-recovery goal for the energy price limits should be documented more explicitly in the Wholesale Electricity Market Rules, and if so whether any changes to the cost-recovery goal used in recent energy price limits reviews are warranted prior to the start of the new spot market.

[13] Refer to the Position Paper, page 68, for details of the proposed guidelines.

[14] It is proposed that the Economic Regulation Authority will be responsible for the ongoing maintenance and review of the guidelines.

[15] Final prices from the co-optimisation process can include the cost of backing off generating units (to provide ancillary service capacity) and producing energy from more expensive units.

3. Consideration of what price cap should apply to spot market energy prices, which like ancillary service prices can exceed offer prices due to the effects of co-optimisation.

3.3 STEM changes

1. Consideration of how to best address two potential concerns with the implementation of the STEM under the new market arrangements:
   - how to prevent a generator with capacity obligations from being required to sell capacity through the STEM when it reasonably anticipates being constrained off due to a network constraint in the spot market; and
   - how to allow market participants to account for capacity they expect to be cleared in the ancillary service markets in their STEM offers.[16]
2. More generally, consideration of what additional measures may be required to prevent the exploitation of differences between the STEM and the spot market to create inefficient arbitrage opportunities.

[16] Refer to the Brattle Group Report, pages 34-35, for a more detailed discussion of these implications.

4. Proposed timing and consultation

Substantive work on the elements listed above is expected to begin early in 2017, following completion of higher priority design work required to support the Australian Energy Market Operator's system development timeframes.

For those elements involving changes to the Wholesale Electricity Market Rules, the Energy Market Operations and Processes project team will consult with the Economic Regulation Authority, the Australian Energy Market Operator and the Energy Market Operations and Processes Consultation Group to develop one or more design papers for public consultation. Following public consultation, draft rules will be prepared and published for additional consultation, before they are finalised.

At this stage, it is expected the design papers will be published by June 2017 and draft rules by September 2017.

Draft SRMC bidding guidelines will also be developed in consultation with the Economic Regulation Authority, the Australian Energy Market Operator and the Energy Market Operations and Processes Consultation Group.[17] While details of the development approach are yet to be finalised, it is expected this will involve publication of an initial discussion paper for public consultation in mid-2017, followed by a position paper later in that year.

[17] The Consultation Group comprises representation from the different classes of market participants to inform the more detailed design of reforms to the energy market operations and processes.

Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia

PREPARED FOR

Government of **Western Australia**
Department of **Finance**
Public Utilities Office

PREPARED BY

Samuel A. Newell

Toby Brown

Walter Graf

James D. Reitzes

Henna Trewn

Kai Van Horn

1 September 2016

This report was prepared for the Public Utilities Office within the Department of Finance in Western Australia. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Table of Contents

Executive Summary

The Public Utilities Office (PUO) engaged The Brattle Group to review market power mitigation mechanisms that could be applied to the wholesale electricity market in the South West Interconnected System (SWIS). This review occurs in the context of reforms planned for July 2018 to align the SWIS's Wholesale Electricity Market (WEM) operations with the National Energy Market (NEM), including the NEM's security-constrained co-optimisation of energy and ancillary services markets. The planned reforms include broader changes to the WEM, including introducing a capacity auction, although our focus here is the energy market.

With one dominant gentailer in the WEM, the market is structurally not competitive. Market power mitigation is clearly needed to achieve least-cost outcomes similar to a competitive market. This whitepaper addresses the following key questions:

- What are the objectives of market power mitigation, and what criteria should be used to evaluate alternative approaches?
- How well does the existing market power mitigation approach work, and how can it be improved, particularly to accommodate the planned transformation of market operations to align with the NEM?
- How well do alternative approaches compare, considering lessons learned from the existing WEM and from the NEM, New Zealand, United Kingdom, and other similar power markets?
- Which approach best meets the established evaluation criteria, given the WEM's particular market design and market structure?

Relatedly, we have been asked by the PUO to evaluate whether to continue, change, or eliminate the Short Term Energy Market (STEM) component of the current WEM, by comparing benefits and costs of the STEM and several alternatives that stakeholders have suggested.

Conclusions about Market Power Mitigation

The goal of market power mitigation is to recreate the maximally efficient outcome of a competitive market. In the WEM, where a capacity mechanism complements the energy market, the competitive ideal is for energy offers to reflect suppliers' short-run marginal costs (SRMC).

"SRMC" should be defined as "all costs that a supplier without market power would include in forming its profit-maximising offer." This includes all costs of generating energy that are "marginal" over a dispatch cycle in that they would not have been incurred if the generator had been available but not running. It encompasses but is not limited to: fuel and non-fuel startup costs amortised over a reasonable expectation of output; all fuel costs incurred once the unit is started up; variable operating and maintenance costs; and any opportunity costs, such as the opportunity cost of fuel that could otherwise have been sold. Failing to account for these costs in forming a competitive offer would not maximise profits for a price-taking supplier lacking market power, and it would lead to uneconomic operating decisions: submitting a lower offer would risk having to produce when prices do not cover all costs caused by producing; submitting a higher offer would risk failing to clear the market and earn net revenues when prices exceed one's costs.

SRMC-based offers support operational efficiency by allowing the system operator to dispatch the lowest-cost available resources. Furthermore, resources with SRMCs below the clearing price earn net energy revenues, supporting investment in the most economically efficient *mix* of technologies. Meanwhile, the capacity mechanism provides additional fixed cost recovery to attract and retain sufficient *total* capacity to meet reliability objectives.

Having established that attaining SRMC-based prices should be the primary objective of market power mitigation in the WEM's energy market, we present criteria for evaluating the relative merits of each potential mitigation approach:

- Primarily, the ability to achieve SRMC-based pricing;
- Avoidance of false positive interventions and significant false negatives;
- Cost effectiveness, including costs incurred by the market monitor as well as costs imposed on market participants;
- Transparency in how rules will be implemented and enforced; and
- Timeliness, that is, feasibility of implementation by the July 2018 deadline.

After considering a range of options, we recommend keeping the WEM's current approach to mitigating market power, with some refinements. The current approach works by requiring that suppliers offer energy at their "reasonable expectation of SRMC" in both the STEM and the balancing market. This requirement is enforced by the threat of punitive action if suppliers do not comply, "when such behaviour relates to market power." This type of approach to mitigation is commonly used in other markets and is known as *"ex post"* behavioural mitigation because it governs offer behaviour as opposed to market structure and because it functions after the market clears. *Ex post* approaches rely on judgment and bespoke analysis rather than (only) formulaic testing.

The primary shortcomings of the current approach are that neither "reasonable expectation of SRMC" nor "when such behaviour relates to market power" are defined in the WEM Rules, and there is considerable confusion regarding these terms among market participants. Specifically, market participants are unsure which costs they are allowed to include when constructing their offers. This lack of clarity increases market participants' risks and potentially raises the market monitor's enforcement costs.

We make the following recommendations for improving the current approach, based on our review of the characteristics of the WEM, the market power mitigation mechanisms used by other markets that share some common features with the WEM, and economic principles:

1. Revise the Wholesale Electricity Market rules limiting generator offers so that they clearly do not refer to *intent*, an elusive matter to prove. Change "when such behaviour relates to market power" to "when the supplier has market power and their behaviour raises prices above competitive levels." Here, "market power" is the ability to profitably raise the market price;
2. Clarify the definition of "SRMC" as described above;
3. Consider whether to increase the current offer cap so generators can more reliably recover their SRMCs;
4. Continue to use screening analyses as part of a behavioural market power mitigation approach focused on *ex post* observed deviations from SRMC, subject to the above revisions. Screens can identify possible violations and trigger further investigation when warranted;
5. Mitigate the balancing market and the STEM consistent with the above revisions; and
6. Apply essentially the same approach to mitigating the ancillary services markets.

The other options we evaluated for mitigating market power in the WEM do not satisfy the evaluation criteria as well as the revised current approach. We discuss *ex ante* mitigation, where generator offers are sometimes changed by the market operator or monitor when market conditions are particularly conducive to the exercise of market power. This approach is unsuitable for the WEM because it requires the market monitor to have information regarding generators' costs that is unlikely to be available when facing non-transparent gas markets and uncertainty regarding the generator's likely output profile.

We examine “semi-regulated forward sales” approaches, which require or incentivise dominant suppliers to function as market makers and offer standard products bilaterally or on centralised exchanges; these approaches are used in New Zealand and the United Kingdom. We find that these approaches significantly increase liquidity of forward markets but are not sufficient to fully mitigate market power. Thus, this approach fails to meet the primary objective outlined above.

Another approach we review involves requiring dominant suppliers to sell some or all of their generation forward through long-term contracts in such a way that diminishes their long positions and reduces their incentive and/or ability to exercise market power. The key would be to determine the contractual quantities of sales needed to reduce the major suppliers’ net long positions much of the time, what types of contractual terms would work for both buyers and sellers in the WEM, and how to ensure reasonable pricing of contracts.

If contracts effectively make the market structurally more competitive and/or transfer operational control of facilities, they reduce the likelihood that suppliers exercise market power. However, a behavioural market power mitigation mechanism also would be needed to discipline behaviour under those temporal conditions where the market is still susceptible to market power. Uncompetitive conditions are inevitable because it would be impossible to construct a schedule of forward contractual sales that would perfectly match the dominant supplier’s long position at all times. Moreover, even moderately-sized suppliers can have market power during peak demand periods when supplies become tight. Market power can become especially acute locally when transmission constraints protect local suppliers from competitors.

Yet, with generation sold forward through long-term contracts, the instances of substantial market power would become less frequent and less severe. Fewer instances of abuse would elude detection under the behavioural mitigation mechanism, and fewer costly investigations would have to be undertaken. We therefore recommend improving the structural competitiveness of the market through long-term contracts if not physical divestiture, while retaining behavioural market power mitigation mechanisms. Structural reform could be accomplished in the long term, although not by July of 2018.

Conclusions about the STEM

The STEM is a centrally-administered day-ahead market where market participants can trade around their longer-term contractual positions without having to arrange a short-term bilateral trade, without waiting until real-time, and without being exposed to the volatility of the balancing market. The STEM offers liquidity and competitive prices by imposing must-offer obligations and other market power mitigation measures—which are essential in a market as concentrated as the WEM. This helps small retailers to access more competitive wholesale markets and offer attractive retail prices, ultimately benefitting consumers.

We recommend continuing the STEM within the new market design because no alternatives we evaluated provided better value. Bilateral-only markets or independently-run exchanges do not provide the same competitive pricing because they cannot impose effective market power mitigation. The only alternative we considered that could provide similar value is an AEMO-run exchange with market-maker provisions applied to Synergy. However, we do not see how this would improve on the STEM, and designing the required market-maker provisions would be complicated.

I. Introduction

A. Context: The Electricity Market Review and Proposed Reforms

Western Australia's Minister for Energy initiated a comprehensive "Electricity Market Review" in 2014, motivated primarily by the rising cost of electricity in the South West Interconnected System (SWIS).[1] The Review examined the SWIS's structure, design, and regulatory regime. It sought ways to reduce costs while shifting future investment fully to the private sector.[2]

Phase 1 of the Electricity Market Review identified an urgent need for industry and market reform in the electricity sector to address a problem of high and increasing costs of electricity services. Phase 2 of the Electricity Market Review was launched by the Minister for Energy on 24 March 2015. It aimed to give effect to Government's preferred reform options to achieve the Electricity Market Review Objectives, reforming existing arrangements, and retaining the energy plus capacity market structure, rather than transitioning to an energy-only NEM-like market.[3]

Reform projects under Phase 2 can be categorised into four workstreams—Network Regulation, Market Competition, Institutional Arrangements, and Wholesale Electricity Market Improvements.

As part of the Wholesale Electricity Markets Improvements workstream, the Western Australia Public Utilities Office (PUO) published a position paper in March 2016 proposing specific market reforms for the wholesale energy and ancillary service (E&AS) markets.[4] The PUO noted that the current market systems and processes do not account for physical network constraints, and that reforms are necessary to improve efficiency while ensuring system security and harmonising the wholesale electricity market with other ongoing

---

[1] See Western Australia PUO (2014).

[2] *Ibid.*, p. 1.

The Review had three objectives: (1) reducing costs without compromising safety and reliability, (2) reducing "Government exposure to energy market risks, with a particular focus on having future generation built by the private sector without Government investment, underwriting or other financial support," and (3) attracting private-sector participants to facilitate long-term investment.

[3] Nahan (2015).

[4] Western Australia PUO (2016a).

reforms. The PUO proposed to adopt a security-constrained market design, implement individual facility bidding for all participants, and co-optimise the energy and ancillary markets.[5] The PUO's proposed design includes later gate closure, shorter dispatch cycles, and the use of the Australian Energy Market Operator (AEMO)'s dispatch engine, as well as several supplementary changes to market operations and processes that will support closer alignment with the NEM.[6] The Minister for Energy endorsed the proposed design principles on 28 July 2016.[7]

The PUO's position paper noted that the Wholesale Electricity Market is still far from fully competitive. While the dominant position of Synergy as both a generator and a retailer provides the most obvious example of market power, the network configuration and small size of the SWIS means that many generators can hold locational market power during periods of network congestion.

The paper correctly explained that market power can be applied in several ways to influence pricing outcomes, including: withholding generation, to create conditions of shortage and so increase prices; and submitting offers at excessive prices.

The position paper proposed several reforms to the energy and ancillary service markets in the SWIS. The paper invited stakeholder submissions in respect of the proposed reforms, including requests for feedback on several specific matters. The majority of the submissions received were either broadly supportive of the proposed reforms or were limited to matters of commercial relevance to the submitting party.

B. Points Addressed in this Whitepaper

The position paper recommended no fundamental changes to the market power mitigation measures currently in place. The position paper did note that some refinements may be needed to reflect specific design features of the new real-time markets and to provide greater clarity to market participants about their obligations.

Submissions received by the PUO on the position paper indicated that opinions on the value of short-run marginal cost (SRMC) based bidding obligations and the need for clarity on these obligations varied widely. After considering the submissions received, the PUO decided to

[5] Western Australia PUO (2016a), pp. vii-ix.

[6] Western Australia PUO (2016a), p. ix.

[7] Government of Western Australia (2016).

undertake a broader review of market power mitigation measures for the energy and AS markets and to publish a separate paper on this matter during the second half of 2016 for stakeholder consultation.

The PUO asked that we address the following points regarding the mitigation of market power:[8]

- Relevant considerations for determining an appropriate mechanism for mitigating market power in the WEM, along with criteria to assess the relative merits of alternative mechanisms. We define objectives and evaluation criteria in Section II.A of this whitepaper.
- Advantages and shortcomings of the current mechanisms for mitigating market power in the WEM, which oblige participants with market power to submit offers no greater than their reasonable expectation of the short-run marginal cost (SRMC) of generating the relevant electricity. We evaluate the current mechanism in Section II.B.
- Opportunities for the current market power mitigation measures to be retained, but improved. We identify potential improvements in Section II.C.
- Whether there are better alternatives for mitigating market power in light of the WEM's characteristics and the evaluation criteria identified above. Section II.D evaluates alternatives, considering:
  - Identification, at a high level, of alternative mechanisms for mitigating market power in the WEM that may promote competitive and efficient market outcomes, and the advantages and disadvantages of the alternative mechanisms relative to the current mechanism.
  - Mechanisms for mitigating market power applied in the National Electricity Market, the United Kingdom, New Zealand and other relevant markets, and the potential relevance and applicability of these mechanisms to the WEM.
  - Identification, at a high level, of the implementation requirements for the alternative market power mitigation mechanisms described above.

---

8 Several enforcement actions in the U.S. have involved the placement of intentionally below-cost offers for generation into electricity markets to garner out-of-market or other types of payments, the net result of which was profitable to the generation owner. The mitigation of such behavior is premised on market rules that prohibit fraud or the creation of an "artificial" price, not on the acts of withholding that typify market power abuse. While we want the PUO to be aware of these issues, the scope of this whitepaper is limited to the mitigation of market power used to inflate market prices above competitive levels.

- Identification of circumstances in which market power mitigation in the energy component of the WEM may no longer be required. This is addressed in Section II.E, Long-Term Considerations.

The PUO also asked us to address a somewhat related question that stakeholders have raised: whether to continue, change, replace, or eliminate the current market's Short Term Energy Market (STEM). We address this question in Section III, starting by describing the purpose of the STEM for providing buyers access to a liquid, competitive day-ahead market for hedging exposure to the balancing market. We then evaluate alternative options' ability to provide similar benefits, while considering potential implementation costs and timing.

II. Market Power Mitigation

The Electricity Market Review's proposed reforms to the wholesale energy market and capacity mechanism are consistent with the widely accepted economic principle that competitive markets can minimise costs. Competitive markets do so by rewarding the most cost-efficient suppliers and by spurring suppliers to reduce their costs—by innovating, operating, and investing as efficiently as possible.

However, an electricity market may not behave competitively if it is highly concentrated in terms of potential suppliers. Under these conditions, suppliers may have both the ability and the incentive to physically or economically withhold output,[9] raising prices and creating economic deadweight loss.

To prevent such outcomes, most electricity markets, particularly those that are significantly concentrated, employ some form of market power mitigation.[10] The WEM is no exception and in fact has much greater concentration than many electricity markets, with one particularly dominant player.[11] Mitigating market power is therefore essential for achieving the system-wide cost-minimising results that are associated with a fully competitive market.

9 "Physical" withholding refers to a situation in which a unit is declared unavailable (*e.g.*, for maintenance) and "economic" withholding refers to a situation in which a unit is offered into the market at such a high price that there is a negligible chance that it will be dispatched.

10 By "market power mitigation" we mean rules designed to constrain the behaviour of market participants in addition to the provisions of general competition law.

11 Synergy owns or has long-term contracts for around 70 percent of total generating capacity in the SWIS.

The key questions are, what specifically should market power mitigation aim to do, and how should it be implemented in the WEM?

These questions were addressed when developing the WEM's current market power mitigation procedures. However, stakeholders are raising them again as part of an ongoing debate and in light of the planned reforms to align the energy market with the NEM and to adopt a new capacity mechanism design.

Below we address these questions for the energy market only, not for the capacity mechanism. We start by establishing the objectives of market power mitigation and identifying Western Australia's specific characteristics that affect the design of effective market power mitigation. We then present a range of market power mitigation options, synthesising lessons learned from the existing WEM and from the NEM, New Zealand, United Kingdom, and other similar markets. Finally, we evaluate which approach best meets the established evaluation criteria, given the WEM's particular market design and market structure.

A. OBJECTIVES AND EVALUATION CRITERIA

1. Objectives

The objective of market power mitigation is to recreate the efficient outcome of a competitive market. But what would a competitive market look like in the WEM? A key feature of the WEM is that it is really two complementary sets of markets: a capacity market to secure enough installed capacity to be able to meet demand on the hottest day of the year, consistent with reliability objectives; and an energy and ancillary services market to meet real-time needs, given the capacity available. The latter is the focus of this whitepaper, but it is affected by the presence of the capacity market. If the capacity market provides sufficient recovery of fixed costs to meet reliability objectives, the energy market need not provide any more than the SRMC of the marginal energy resource. This is what competitive markets would produce and what the market power mitigation mechanism should emulate, as we illustrate below. SRMC represents all of the additional costs incurred by a generator when it is generating, and excludes costs that it incurs whether it generates or not.

But first consider an energy-only market, where there is no capacity mechanism. If the market is *perfectly* competitive all the time, each supplier would offer to generate at its SRMC. Offering at any price higher than SRMC would risk not clearing and thus losing a chance to earn net revenues whenever prices exceed cost. In such a market, the most efficient "baseload" resources will earn the highest net revenues, and the least efficient "peaking" resources will earn very little. The problem is that the peaking resources will not recover their fixed costs (the "last" unit that is only required in the hottest hour of the year may not recover any fixed costs at all); other resources may earn more, but they typically have higher fixed costs and will likely not earn enough overall to stay in business. Such a market will not meet reliability objectives and is not sustainable. This is why energy-only markets have to allow energy prices higher than SRMC. Some allow offers above SRMC that are rational for supplies to submit when market conditions become tight and competition becomes thin. Some impose administratively-determined "scarcity pricing," for example when operating reserves are sacrificed for energy. And most energy-only markets have much higher price caps than non-energy-only markets.

Markets with a capacity mechanism have a different solution to recovering fixed costs. They pay capacity prices sufficiently high to provide all the "missing money" needed to meet resource adequacy objectives (money that is "missing" in an energy-only market at SRMC). They do so as follows: the capacity market will clear at a price where the demand curve intersects a competitive supply curve; the marginal capacity resource will be paid its offer and set the capacity price for all other resources.[12] If that marginal resource's capacity offer was competitive, it is indifferent between committing to provide capacity and not (*i.e.*, retiring or not entering the market in the first place). That is, its offer price would just recover its avoidable going-forward fixed costs that are not expected to be recovered in the energy market. All other cleared capacity resources are inframarginal and expect to earn more than their net fixed costs. Uncleared capacity resources from higher up the supply curve had higher net fixed costs. But the market settles at just the right price where enough resources clear to meet demand and are happy to do so because they at least recover their fixed costs. This mechanism works no matter how little fixed cost recovery may have occurred in the energy market.

Because the WEM includes a capacity mechanism, the competitive ideal—which the market power mitigation should emulate—is for energy offers and clearing prices to reflect SRMC. This will not cause missing money. It will support economic efficiency. The market will support *operational efficiency* by sending short-term price signals to dispatch only the lowest cost resources. SRMC-based energy prices also support *investment efficiency* by providing greater net energy revenues to generators with lower SRMCs and encouraging investment in the most economically efficient mix of technologies. Meanwhile, the capacity mechanism

12 For a complete description, see Western Australia PUO (2016b).

provides additional cost recovery to attract and retain enough *total* capacity to meet reliability objectives.

2. Criteria for Evaluating Mechanisms

The primary criterion for evaluating a candidate market power mitigation mechanism for the WEM is that it achieves the objective described above: it must successfully mitigate market power and yield a WEM that reasonably approximates a fully competitive market. Specifically, the approach must *achieve SRMC-based energy prices*. This criterion is the main differentiator among possible approaches. If this criterion is met, we consider the following secondary criteria regarding practical implementation considerations: *Avoid false positives and egregious false negatives*. This is important to specify as the market monitor will inevitably have imperfect information on resources' actual costs. As such, the market power mitigation process should be designed to avoid too many "false positives" regarding the alleged exercise of market power, which can lead to costly disputes, potentially distorted market prices, depressed participation in the market, and ultimately higher costs to consumers. Some "false negatives" can be tolerated, where an exercise of market power is not identified for purposes of mitigation, but egregious false negatives cannot.

- *Cost effectiveness*. It is important to avoid excessive administrative overhead and implementation costs for the market operator, market monitor or market participants.
- *Transparency in how rules will be interpreted and enforced*. It is important for the standards to be defined clearly so that suppliers can participate in the market without facing significant uncertainty or risk of being penalised for competitive offer behaviour (*i.e.*, false positives).
- *Timeliness*. Any changes must be feasible to implement given the July 2018 deadline.

B. Evaluation of WEM's Current Market Power Mitigation Mechanism

We first present a brief discussion of market fundamentals that affect market power mitigation in Western Australia. We then describe the current approach to market power mitigation, and its advantages and potential shortcomings.

1. Relevant Energy Market Characteristics

The WEM is a small, concentrated market with one very dominant entity, Synergy, which currently generates approximately 50 percent of total electricity in the WEM[13] and has access

13 Synergy (2016).

to another 20 percent of generation through long-term bilateral contracts.[14] Clearly, such a dominant supplier would have both the incentive and the ability to exercise market power under many circumstances, absent mitigation.

Other suppliers are smaller, but they too could have market power from time to time, particularly when transmission constraints reduce the size of the relevant market. We understand that transmission constraints in WEM are expected to become increasingly common. Since transmission congestion is managed through pay-as-bid, out-of merit-order payments, it may be possible for generators to exert locational market power in the balancing market.

Although the structural factors noted above necessitate market power mitigation, the WEM has two factors making it difficult to determine a competitive benchmark for what offers and prices should be: one-part energy offers and non-transparent gas costs. These factors make it difficult for the market monitor to have accurate and timely information regarding a generator's SRMC. As a result, market power mitigation must be implemented carefully so as not to force generators to operate when they are not economic. For example, the formulaic *ex ante* offer mitigation practised in many U.S. energy markets may not be appropriate.

- *One-part energy offers*. In the WEM, generators submit "one-part" energy bids to cover all of their costs of operating, including incremental fuel and O&M costs as well as the minimum startup costs, no-load costs,[15] and any other costs incurred. Whether an offer is judged competitive depends strongly on the assumed duty cycle over which startup costs can be recovered. In the WEM, a generator submits independent offers for each trading interval, but the SRMCs of generating in each trading interval are not independent, meaning that whether the offer for a particular trading interval is at or above SRMC cannot be determined without considering the adjacent windows. This is in contrast to most U.S. markets, where generators provide three separate cost-based offers (a startup cost, a no-load cost, and a monotonically increasing incremental energy cost curve) and the system operator optimally commits and dispatches resources over all periods in the day. Although only the incremental energy offer components set prices, all generators that the system operator commits are entitled to

[14] Derived from Hansard where Synergy's share of the SWIS generation market referenced as 70 percent; see, Assembly Estimates Committee B (2016).

[15] The "no-load" is the theoretical cost to run at zero net output. Even if a generator cannot run at such a low output level, the no-load cost is the amount that has to be added to the integrated, monotonically-increasing incremental fuel cost curve to express the total fuel cost. See PJM (2011).

"uplift" payments if necessary to fully recover all of their as-offered costs on a daily basis or cycle basis.

- *Non-transparent gas costs*. Generators' relevant gas costs are not transparent in the WEM. Gas-fired generators in the WEM generally obtain fuel through long-term bilateral contracts, and even if a particular generator's contract price is fairly stable, the opportunity cost impact of burning gas at a particular time may depend on whether the contracts are take-or-pay, whether storage is available, and whether transportation charges are volumetric or fixed. Moreover, the spot market, which may be the most relevant measure of opportunity cost, is thin and non-transparent.

WEM's reformed energy market commencing on 1 July 2018 will retain these same basic features plus additional ones: offers in the balancing market will be facility-based instead of portfolio-based; the balancing market (including the iterative pre-dispatch process leading up to the physical dispatch) will account for transmission constraints and co-optimised energy and ancillary services; constrained-on generation will be compensated as bid while constrained-off generation will not be compensated. Other notable new features include shorter gate closure and settlement cycles, and 5-minute dispatch intervals with 30-minute settlement at the average price over the six intervals.

2. Overview of the Current Approach to Market Power Mitigation

The WEM Rules preclude a generator from offering into the STEM and balancing market above the generator's "reasonable expectation of the short run marginal cost of generating the relevant electricity…when such behaviour relates to market power."[16] Consistent with this guideline, the current WEM has three main mechanisms to mitigate market power: must-offer requirements, *ex ante* energy offer limits, and, most importantly, *ex post* reviews.

First, generators with capacity credits are required to offer available capacity into the STEM and balancing markets. This prevents physical withholding, but does not prevent generators from offering at excessively high prices (economic withholding); this is addressed by other mechanisms.

Second, the WEM has two *ex ante* energy price limits in the STEM and balancing markets:

- The Maximum STEM price (which applies in dispatch intervals for which gas is the fuel for the highest cost peaking plant); and

16 Western Australia PUO (2016a), p. 66.

- The Alternative Maximum STEM price (which applies in dispatch intervals for which liquid fuel is required for the highest cost peaking plant).

These price limits are set to recover the short-run average cost (SRAC) of the highest cost peaking plants in at least 80 percent of dispatch cycles between 0.5 and 6 hours long.[17] In practice, this constraint is rarely binding, and prices rarely clear at this level. Between July 2012 and December 2015, the Balancing Price reached the constraint in only 50 trading intervals, and the STEM Clearing Price never reached the constraint.[18] The current Maximum STEM Price is $240 per MWh, and the current Alternative Maximum STEM Price is $367 per MWh.[19]

Finally, and perhaps most importantly, the market monitor[20] conducts various screening analyses after the fact. We understand that these screens may compare offers to benchmarks and to prior offers and may compute measures of market power. When the screens indicate a possible exercise of market power, the market monitor would ask the supplier for an informal explanation of its behaviour before initiating a formal investigation.[21] If a formal investigation[22] finds that a supplier exercised market power, that supplier could be subject to civil penalties.

An important distinction between different types of market power mitigation measures is whether mitigation operates *ex ante*, on a formulaic basis, or *ex post* requiring a degree of judgement. The Maximum STEM Price and Alternative Maximum STEM Price approaches described above are *ex ante* mechanisms: a generator offer price is compared with the pre-calculated caps and, if the offer price is above the cap, the offer is rejected. This mechanism is formulaic and not punitive. In contrast, the rule that suppliers with market power must not submit bids above a reasonable expectation of SRMC is enforced through an *ex post* approach: whether or not a market participant has complied with the rule can be assessed only after the fact, and compliance cannot be determined on a formulaic basis. Even on an after-the-fact basis, it may not be straightforward to determine what SRMC was; judgement is self-

---

17 *Ibid.*, p. 65.

18 *Ibid.*, p 65.

19 AEMO (2016c).

20 As of 1 July 2016, the Economic Regulatory Authority (ERA) has responsibility for compliance and enforcement functions, with support from the AEMO.

21 As of October 2015, there has been only one investigation related to this rule. In 2014–15, ERA investigated Vinalco Energy Pty Ltd (Vinalco), a supplier owned by Synergy. (ERA) (2015a)

22 Undertaken by the Electricity Review Board.

evidently required in determining a "reasonable expectation"; and it may not always be clear whether a supplier has market power.

Since an *ex post* approach is not formulaic, it is relatively costly to apply. If the *ex post* approach is calibrated to catch few false positives and therefore only the worst offending behaviour, it is necessary that the consequences of being found in breach of the rules should be punitive (*i.e.*, should not be equivalent to the outcome that would have been obtained if the market participant had not breached the rules—the market participant will be worse off having breached the rules and been caught than if they had not breached the rules in the first place). Because the *ex post* approach can result in punitive consequences for offering above SRMC, the existence of the mitigation mechanism provides a disincentive to breach the rules.

3. Advantages of the Current Approach

The current approach to mitigating market power in the WEM has several advantages. First, it explicitly targets SRMC-based pricing, which accords with the primary objective of mitigation we established above.

Additionally, the current approach utilises primarily *ex post* mitigation, which is more suited to certain institutional features of the WEM than *ex ante* mitigation. This is due to several factors that make it difficult for the market monitor to know generators' costs *ex ante*. The required one-part energy offers require participants to amortise no-load and startup costs in their generator offers in a way that depends on their expected duty cycle. Because the market monitor cannot observe each generator's expected duty cycle, only the realised cycle, it is not possible to calculate the generator's expected SRMC even with perfect information on actual costs. This precludes formulaic *ex ante* mitigation. Gas costs are also difficult for the market monitor to observe, further hindering the market monitor's accurate calculation of *ex ante* costs. For further discussion, see Sections and II.B.1 and II.D.1.a.

4. Potential Shortcomings of the Current Approach

The current approach has several shortcomings and potential limitations. Perhaps most importantly, market participants need greater clarity regarding the definition and interpretation of the key clauses governing their behaviour. The current guidelines, "reasonable expectation of short run marginal cost" and "when such behaviour relates to market power," are unclear as neither "SRMC" nor "market power" are defined in the WEM

Rules.[23] This lack of clarity increases market participants' risks, and potentially increases the market monitor's enforcement costs.

Relatedly, the current market rules limiting generator offers seem to place an unnecessary burden on the market monitor to prove that a market participant *intended* to exercise market power before applying corrective action. Clause 6.6.3 (limiting generator offers into the STEM) and Clause 7A.2.17 (similarly limiting offers into the balancing market) have similar language that a "Market Participant must not…offer prices…in excess of [their] reasonable expectation of the short run marginal cost of generating the relevant electricity by the Balancing Facility, *when such behaviour relates to market power*"[24] (emphasis added). The clause, "when such behaviour relates to" seems to refer to intent. Intent is notoriously difficult to investigate and prove. Having to prove intent increases enforcement costs and reduces transparency surrounding how the rules are interpreted and enforced.

Another potential shortcoming of the current approach is that it was designed for the current WEM and may not be as well suited for the reformed WEM. We discuss in the following section how the current approach can be extended to accommodate the balancing market, the STEM, and the ancillary services markets in the new design.

A perceived flaw of the current approach identified by market participants is that SRMC is too low and does not allow suppliers to include all of their short-run variable costs of operating in their SRMC-based offers. This is related to the issue described above that the definition of SRMC is unclear. A properly broad definition of "SRMC" would certainly include all incremental costs from generating rather than not, as discussed below. However, other market participants have argued that generators should be able to recover more of their fixed costs through the energy market. While it is true that some fixed costs will be recovered in the energy market by inframarginal producers, competitive energy offers and prices should not consider fixed costs, as discussed in Section II.A.1.

C. Recommendations for Improving the Current Approach

We make the following recommendations, based on our review of the future characteristics of the WEM, the market power mitigation mechanisms used by other markets that share some common features with the WEM, and economic principles:

---

23 Western Australia PUO (2016a), p. 66.

24 *Ibid.*

1. Revise the WEM Rules limiting generator offers so that they clearly do not refer to *intent*, an elusive matter to prove. Change "when such behaviour relates to market power" to "when the supplier has market power and their behaviour raises prices above competitive levels." Here, "market power" is the ability to profitably raise the market price;
2. Clarify the definition of "SRMC" consistent with the competitive market standard;
3. Consider whether to increase the current *ex ante* offer cap so generators can more reliably recover their SRMCs;
4. Continue to use screens as part of an *ex post* SRMC-based approach, subject to the above revisions. Screens can identify possible violations and trigger further investigation when warranted;
5. Mitigate the balancing market and the STEM consistent with the above revisions; and
6. Apply essentially the same approach to mitigating the ancillary services markets.

1. Amend Rules to Remove Suggestion of Intent

We recommend that the phrase "when such behaviour relates to market power" of clauses 6.6.3 (limiting generator offers into the STEM) and 7A.2.17 (limiting offers into the balancing market) in the WEM Rules be changed to "when the supplier has market power and their behaviour raises prices above competitive levels;" Here, "market power" is the ability to profitably raise the market price.[25]

This revision captures the important point that the market monitor is concerned only about bidding above SRMC when it affects market outcomes, without requiring that they prove intent. This change may decrease the costs of investigation and allow the market monitor to mitigate market power even when intent cannot be proven. Furthermore, the change should improve transparency regarding how the rule is interpreted.

---

25 The definitions and rules could be extended to the opposite situation, where a large gentailer's portfolio position becomes net short and it has the ability and incentive to drive prices *downward* by submitting offers below SRMC. Such behavior could distort market outcomes away from the competitive ideal and erode economic efficiency. As footnote 8 notes, this possibility is outside of the scope of this report. If this possibility becomes a significant concern, the PUO may wish to consider modifying the rules to prevent it.

2. Clarify Definition of "SRMC"

A clear definition of "SRMC" is needed to allow suppliers to offer their full SRMC but not more. A clear definition can also reduce suppliers' risks of accidentally violating rules when participating in the market.

We propose defining "SRMC" as "all costs that a supplier without market power would include in forming its profit-maximising offer."[26] This includes all costs of generating energy over a dispatch cycle that would not have been incurred if the generator had been available but not running. It encompasses, but is not limited to, the following types of cost: fuel and non-fuel startup costs amortised over a reasonable expectation of output; all fuel costs once the unit is started up (including no-load costs); operating and maintenance costs that increase when producing energy; and any opportunity cost, such as the opportunity cost of fuel that could otherwise have been sold. In the case of the STEM, other opportunity costs and constraints may apply, as discussed in Section III.C.1 below. This relatively broad definition reflects the objective of market power mitigation to emulate a competitive market.

Uncertainty has to be considered in establishing an SRMC standard. At the time a generator forms its offers, it may not know how much energy it will ultimately generate since it cannot perfectly predict system loads, competing generators' outputs and costs, and transmission constraints. This renders uncertain the amount of output over which to amortise startup costs. Uncertainties may surround fuel opportunity costs and other costs as well.

Any *ex post* review of offers must recognise these uncertainties and apply a "reasonableness" standard. However, we cannot specifically define "reasonableness" in general. The ERA would have to judge the reasonableness of a supplier's explanations in light of the information it had at the time it formed its offers.

3. Consider Whether to Increase the Current *Ex Ante* Offer Cap

In the WEM, *ex ante* offer caps should be used only as a backstop to prevent the most egregious exercises of market power from affecting market settlement. This is because *ex post* mitigation is the primary tool for disciplining offers, and if it is doing its job, *ex ante* caps are

26 We recognize that "SRMC" is sometimes interpreted narrowly to include only incremental costs resulting from infinitesimally small increases in quantity produced. However, a supplier without market power needs to consider the startup decision. Thus, any practical use of the marginal cost concept must account for all related costs over the dispatch cycle under consideration.

not needed. If *ex post* mitigation is successfully disciplining offers to adhere to SRMC, then any time the *ex ante* cap binds, it may be preventing a resource from recovering its SRMC.

We therefore recommend continuing only loose *ex ante* offer restrictions, comparable to the current price caps for liquid and non-liquid fuels. Those caps are tuned to fully compensate the most expensive peaking resources at least 80 percent of the time. We recommend revisiting this standard and consider raising the cap to cover SRMCs in a greater percentage of dispatch cycles (*i.e.*, with a lower probability of exceedance).

Under the current WEM Rules, market prices can never exceed the highest offers, making the offer cap function as a price cap as well. Once the WEM transitions to co-optimised, security-constrained dispatch with the National Electricity Market Dispatch Engine (NEMDE), market prices could mathematically exceed offer prices. We understand that the PUO will examine whether and how to limit market prices in a separate study.

4. Continue to Use *Ex Post* Screens to Identify the Need for Further Investigation

When using *ex post* mitigation strategies, the market monitor applies screening analyses to identify possible violations that warrant further scrutiny. The market monitor should continue to use two basic types of screens consistent with the principles outlined above to:

1. Identify when market power exists, by defining the relevant market and analysing market conditions and supplier positions; and
2. Identify when a supplier's offers exceed SRMCs.

Because the market monitor lacks perfect information about participants' costs and portfolios, no test will be perfect. Some amount of false negatives is inevitable. False positives will occur as well and can presumably be resolved through investigations. The market monitor will have to tune the screens to avoid too many false positives and costly investigations, while also avoiding egregious false negatives that permit uncompetitive outcomes.

We believe the use of screens will require discretion, not a formula. For example, the screens may indicate that a supplier offered significantly above SRMC but did not seem to have market power. Such a case may still warrant investigation, however, in case the participant indeed did hold market power that was not apparent when conducting the screen.

We discuss in Appendix A some concepts that the market monitor could consider incorporating into its screens if it has not already done so.

5. Apply these Principles to the Balancing Market and STEM

All of the market power mitigation principles and methods we describe should apply to every live offer for every trading interval in the balancing market: from the time the pre-dispatch window opens the day before, through the successive pre-dispatch iterations conducted every thirty minutes, until the final submission used to dispatch the system and settle the balancing market. The pre-dispatch process provides preliminary price signals to help suppliers plan their deployments to produce energy, provide operating reserves, and manage transmission constraints. These preliminary prices (as well as the final prices) must reflect SRMCs in order to achieve an efficient physical dispatch.

Financially, the balancing market is the ultimate market that works backwards to help discipline forward markets, since if forward prices significantly exceeded expected balancing prices, buyers could wait to purchase in the balancing market. However, that discipline is likely not enough to obviate the need for mitigating the STEM since that is a separate market from the balancing market, separated in time, with different information available and different preferences related to hedging, as discussed in Section III.C.

The must-offer provision and the SRMC standard should therefore continue to apply to the STEM to ensure that market remains liquid and competitive. As noted above, however, the SRMC standard needs to account for the (uncertain) information that is available to suppliers at the time they form their offers.

6. Apply Essentially the Same Approach to Ancillary Services

The reformed market will include market-based ancillary services, which will need to be mitigated just like the energy market, due to the concentration of suppliers. The approach to mitigation can be the same as in the energy market, using the same general definition of "SRMC."

Resources providing spinning reserves or load following services cannot simultaneously provide energy with the same portion of their capacity.[27] Providers of these reserves therefore face opportunity costs. If a unit is turned on, its incremental cost of providing reserves is its energy opportunity cost, given by the difference between its incremental energy cost and the energy clearing price. This opportunity cost is recognised by the dispatch engine as it co-

---

27 These frequency control ancillary services are known as "contingency raise" and "regulating raise and regulating lower" services, respectively, in the NEM. See Western Australia PUO (2016a), p. 39.

optimises energy and ancillary services and sets prices for each. However, the dispatch engine does not account for the generator's need to recover its startup costs *even if amortised startup costs were already included in the energy offers.*

For example, suppose one unit has an incremental cost of $30/MWh and another has an incremental cost of $40/MWh, and they each have $20/MWh amortised startup costs, so they offer $50 and $60, respectively. If the $60 unit is marginal in the energy market, the energy clearing price will be $60. Furthermore, suppose the $50 unit is marginal in the spinning reserve market. If the $50 unit does not add startup costs to its offer for spinning reserves, the dispatch engine will calculate an energy-opportunity-cost-based offer of just $10/MWh (*i.e.*, $60–$50). That is clearly not enough to cover startup costs. If the unit is dispatched down to half load to provide half of its capacity as energy and half as reserves, it will recover only half of its startup costs. The unit clearly has to be able to add $20/MWh to its spinning reserve offer so that the dispatch engine will calculate a price of $30 (*i.e.*, $10 + $20).

Therefore, generators offering spinning reserves and load following services have to be able to include startup costs in their SRMC-based offers. Startup costs would be amortised over total expected energy output plus reserves, both in MWh. They would not explicitly add energy opportunity costs to their offers since the dispatch engine accounts for that automatically.

D. Review of Alternative Approaches to Mitigation

Depending on their various characteristics and fundamentals, electricity markets worldwide have adopted a variety of strategies to prevent the exercise of market power. Most have implemented strategies to discipline or directly mitigate suppliers' offers. Some have chosen strategies that aim to reduce or eliminate the underlying incentive market participants have to exercise market power, generally in conjunction with offer mitigation and discipline strategies.

In the sections below, we describe a variety of these mitigation strategies. We provide examples of where each strategy has been used in other markets, and discuss characteristics of those markets where relevant to the particular strategies chosen. Finally, we consider each strategy as a potential option for the WEM, evaluating them against the criteria presented in Section II.A.2.

1. Offer Mitigation and Discipline

The approaches discussed in this section are those that target the offer behaviour of market participants, without changing their fundamental incentives to exercise market power. These strategies can generally be classified as either *ex ante* or *ex post* strategies. *Ex ante* approaches, such as price caps, offer restrictions, and mandated prices, attempt to limit the exercise of market power (or its effects) directly in the day-ahead or spot markets. *Ex post* approaches instead focus on identifying abuses of market power after the market has settled, with the threat of punitive action to disincentivise suppliers from exercising market power when they have it.

a. Ex Ante Market Power Mitigation

Ex Ante Reference Levels

One approach to *ex ante* mitigation is to mitigate supply offers to calculated "reference levels." The market monitor calculates a reference level for each facility that reflects their SRMC. This calculation uses data provided by each participant on costs, including expectations of fuel prices, and on the physical characteristics of each facility. Each offer is evaluated for market power according to the screens discussed below, and when generators are found to have market power and to be offering above the reference level, the offer is reduced to the reference level.

This approach is used in most U.S. markets, including PJM, ISO New England (ISO-NE), New York ISO (NYISO), and Midcontinent ISO (MISO). These markets tend to have capacity mechanisms and, unlike the WEM, allow three-part energy offers. Three-part offers are more directly comparable to SRMC cost components knowable by the market monitor; this key issue is further discussed below.

An example of typical use of *ex ante* reference levels is in ISO-NE.[28] Depending on the results of various screens, resources there may not submit offers that exceed their calculated reference levels by more than a certain amount (50 percent or 300 percent, depending on whether the resource is in a constrained area or is a dominant supplier). When generators submit an offer that is too high, and significantly affects the market clearing price, the offer is mitigated to the resource's reference level.

This approach has several benefits. First, it is transparent, being applied in a formulaic manner. Second, as with other *ex ante* approaches, it is instantaneous, so there is no uncertainty regarding mitigation. These benefits afford generators greater certainty regarding operation and revenues, potentially decreasing the risk of un-economic or inefficient behaviour.

---

28 FERC (2014), p. 8.

However, this approach has certain drawbacks, particularly for Western Australia. The *ex ante* reference level may not accurately reflect the relevant SRMC of a generator because of the one-part energy offer structure and non-transparent fuel markets, as described in Section II.B.1 above. Here, imposing *ex ante* offer mitigation could easily over-mitigate, which can move the market away from the SRMC-based competitive outcome. Over-mitigation can also discourage suppliers from participating in the market in the long-term. We thus rule out this type of *ex ante* offer mitigation for Western Australia.

Blanket Price or Offer Caps

Some markets mitigate market power *ex ante* using blanket caps on market prices or generator offers, either alone or in combination with reference-level mechanisms, as discussed above. Market-wide caps apply to all participants and are generally set high enough that market participants can nearly always expect to recover their SRMC.

Often the price cap will be set as a function of peaking unit characteristics and fuel prices; the frequency with which the cap is updated varies among markets. The WEM has such a cap, as discussed in Sections II.B.2 and II.C.4.

In some markets, a price cap is set much higher than generator offer caps. Prices may rise several multiples above the offer cap when supply is inadequate to maintain operating reserves (for example, by imposing reserve constraint penalty factors, which the energy-ancillary services co-optimisation software will translate into energy prices that can exceed offer caps).[29] In energy-only markets, scarcity pricing provides incentives for adequate investments. Even in markets with capacity mechanisms, scarcity pricing can strengthen incentives for capacity resources to perform whenever they are needed most.

Both price and offer cap strategies have similar drawbacks to those that apply to the reference level approach. When market caps are set too low, this approach has the potential to be overly cumbersome for market participants, limiting their flexibility, constraining operational decisions, and potentially decreasing market efficiency. Alternatively, caps that are set very high and are rarely binding provide little market power mitigation benefit. For these reasons, price and offer caps are generally used in conjunction with other, more flexible approaches to market power mitigation.

29 Other constraints can similarly cause prices to exceed the highest offers. For example, transmission constraints can do so in a nodal market.

WEM's current blanket offer cap is unlikely to provide much market power mitigation benefit, other than as an absolute upper limit, as it is rarely a binding constraint on supplier offers.[30] In fact, in the situation where it does bind and market power is not a factor, the cap may be too low and distort the outcome, pushing the market away from the competitive outcome, as discussed in Section II.C.3.

b. Ex Post Market Power Mitigation

In contrast to *ex ante* mitigation, *ex post* strategies rely on identifying and punishing the exercise of market power after settling the market. Successful *ex post* mitigation requires that identification be accurate enough, and punishment severe enough, that suppliers find it disadvantageous to exert market power in the first place. Unless this is true, suppliers may continue to exert market power to a significant degree, negatively affecting market efficiency.

The major advantage of *ex post* mitigation is it does not risk interfering with supplier's offers based on incomplete information and thus distorting market outcomes. All of the market monitor's actions are conducted after the fact, based on careful consideration of the information available. For example, the market monitor may be able to determine a supplier's portfolio position or fuel prices more accurately. Nevertheless, all *ex post* review must be conducted from the perspective of the supplier when it formed its offers, given the uncertainties it faced at that time.

Ex post mitigation is well suited to a variety of markets with differing structures and operating rules. Whereas *ex ante* mitigation is infeasible in markets with one-part energy bidding, *ex post* mitigation is practical in both markets with one-part and three-part bidding, and regardless of whether the market is energy-only or employs a capacity mechanism.

Most markets employ some type of *ex post* market power mitigation. For example, the Australian NEM (which does not have a capacity mechanism and has no rule about energy offers reflecting SRMC) relies on antitrust laws to mitigate the abuse of market power. Under Part IIIAA of the Competition and Consumer Act of 2010, the Australian Energy Regulator (AER) uses *ex post* strategies based on competition analyses followed by injunctions and penalties.[31] The AER monitors several indicators of competitiveness, such as market shares,

---

30 This refers to the fact that the market price is rarely limited by the offer cap. The offer cap may be binding for individual market participants, who wish they could bid higher, but the market price is affected by these offers in very few dispatch cycles.

31 Murray, *et al.*, p. 10.

the Herfindahl-Hirschman Index (HHI),[32] and the residual supply index (a measure of generator dominance). The AER also considers the percentage of capacity that a generator dispatches when prices are within certain bands, which may illustrate deliberate capacity withholding if some generators reduce output while prices rise (or, it may illustrate technical limitations to plants responding quickly to high prices).[33]

The United Kingdom's electricity market relies on *ex post* mitigation. The market, operated by National Grid Electricity Transmission (NGET)[34] and regulated by the Office of Gas and Electricity Markets (Ofgem), involves a mix of bilateral (contract and over-the-counter) trading, and short-term trading on various organised exchanges; there is no centralised day-ahead spot market.[35] The UK recently established a capacity market as part of the Electricity Market Reform initiative; the capacity market's first auction for delivery in 2018/19 was completed in 2014.[36]

As in the NEM, Ofgem relies on antitrust laws to examine and punish anticompetitive behaviour of electricity generators.[37] Ofgem, in concurrence with the Competition and Markets Authority (CMA), has the power to enforce prohibitions against market power abuse under the Competition Act of 1998. Ofgem commences a formal investigation if there are reasonable grounds for suspecting that an action or behaviour infringes the law.[38] Ofgem applies the Competition Act in the electricity and gas sectors with specific emphases based on the distinguishing characteristics of these industries, such as the limited storability of electricity.[39] Ofgem's market surveillance team monitors market prices daily and investigates unusual situations—such as price spikes or periods of low reserve margin—primarily via publicly- or commercially-available data, and sometimes by obtaining output and bidding information directly from generators through its powers under the Competition Act and

32 The HHI is a commonly used measure of market concentration.

33 AER (2015), p. 59–61.

34 Ofgem (2016).

35 Reitzes, *et al.* (2007), p. 48.

As at September 2007, over 90 percent of power traded in the UK was through bilateral transactions.

36 Ofgem (2015a), p. 69.

37 Garcia and Reitzes (2007).

38 Ofgem (2014), p. 12.

39 Ofgem (2004), p. 15. This report is referenced in Ofgem 2014, and thus references to this document can be considered "as at" 2014.

other legislation.[40] Ofgem uses tests to determine "whether a hypothetical monopolist could profitably sustain prices a small but significant amount above competitive levels."[41] Although the European Court has stated that a consistent market share of 50 percent or more indicates dominance, Ofgem attempts to assess accessibility of substitute products and actual behaviour in determining the existence of market power, rather than focusing on proxy metrics such as market share.[42] Ofgem also checks for instances of predatory pricing by applying either a cost-based or avoidable costs test to assess whether a generator is pricing below average variable or fixed (avoidable) cost, respectively, as a method to damage the position of a competitor.[43]

Furthermore, Ofgem uses pivotality analysis in monitoring the potential for market power abuse in the wholesale electricity market. This analysis looks at the critical nature of a given company's portfolio of power in clearing supply and demand in a particular period to determine whether it can exert market power by withholding electricity.[44] Ofgem can issue an order to stop anticompetitive behaviour, impose a financial penalty, and/or require generators to divest some of their assets.[45]

Most markets that have a capacity mechanism use *ex ante* mitigation, and most markets without a capacity mechanism use general competition law rather than any more detailed rules specific to electricity markets as part of an *ex post* approach. However, we consider that the WEM cannot rely only on an *ex ante* approach: for example, the one-part bidding and the lack of transparency about fuel prices distinguishes the WEM from US markets that rely on *ex ante* mitigation. We also consider that an *ex post* approach in the WEM would benefit from more specificity and precision than a restatement of general competition-law principles. Where there is a capacity market it is reasonable to target SRMC-based prices in the energy market. It therefore makes sense to develop *ex post* mitigation that is more specific than general competition law principles (unlike, for example, in the NEM,[46] where there is no capacity mechanism and where therefore it is not desirable to target SRMC-based prices).

---

40 Reitzes, *et al.* (2007), p. 50.

41 Ofgem (2004), p. 17.

42 Ofgem (2004), p. 21.

43 Ofgem (2004), p. 23.

44 Ofgem (2015a), p. 63.

45 Reitzes, *et al.* (2007), p. 50. As at September 2014, financial penalties could be "up to 10 percent of the company's applicable turnover." See Ofgem (2014), p. 56.

46 See, for example, discussion in Australian Energy Market Commission (2013).

Ex post market power mitigation is a broad category that can include many different strategies. Due in part to this flexibility, we believe an *ex post* mitigation approach satisfies all the evaluation criteria for the WEM.

- It can yield SRMC-based pricing, as long as the threat of punishment for significant deviations is strong enough.
- Because mitigation is conducted after the market clears, there is time to conduct careful evaluations of suspected market power abuses, resulting in minimal false positives and false negatives.
- While investigations can be costly, *ex post* mitigation is generally more cost effective than other approaches, especially some structural approaches discussed in the next section.
- *Ex post* mitigation can be very transparent, especially when the definitions of SRMC and market power are clarified as discussed in Section II.C.
- Finally, because the WEM already relies primarily on *ex post* mechanisms, any desired changes can be feasibly implemented by the July 2018 deadline.

2. Approaches Addressing Incentives

Even when markets employ offer mitigation and discipline strategies discussed above, some markets have additionally chosen to pursue market power mitigation approaches that change market participants' incentives (and sometimes ability) to exert market power in a more fundamental way. These strategies include structural approaches such as divestiture, contractual sales, and other forward contract and standard product approaches.

a. Divestiture of Assets

Some markets have chosen to address significant market power concerns by forcing the largest suppliers to divest some of their generation assets. Smaller suppliers have less ability and less incentive to exercise market power. By reducing the dominant position of key market participants and increasing the number of small participants, these reforms fundamentally change the incentives in the market and bring it closer to the competitive standard. However, this divestiture process can be costly and time-consuming up-front and can increase ongoing costs if the large suppliers have significant economies of scale that are lost.

Although options that involve structural reform to the market are outside the scope of this report, we include this approach for completeness. This approach may merit consideration in the long term, as it is the approach that most directly addresses the cause of market power.

However, this mechanism would not sufficiently mitigate market power when used alone; behavioural market power mitigation mechanisms would still be necessary to address market power occurring during peak loads and/or when transmission constraints bind.

b. Mandated Long-Term Forward Sales

A related alternative is to require dominant suppliers to contractually sell some or all of their generation on a forward basis. This causes their net position to be more balanced coming in to the day ahead and balancing markets. This can diminish their incentive to exercise market power in those markets if the contracted sales are complete enough to minimise their net position.

However, without restrictions on the terms and conditions of the contracted sales, the dominant suppliers still may be able to enjoy the benefits of market power. Since long-term prices are reflective of expectations regarding future spot prices, sellers that have the incentive and ability to withhold power in the spot market will be able to potentially obtain long-term contract prices that reflect their market power.

As a result, the conditions surrounding the contracted sales, including the contract length, should be specified in a manner that precludes contract prices from reflecting the potential to exercise market power (e.g., through a mandated auction process where a specified quantity of power is put up for sale and the seller acts as a price taker, or through a cap on the sale price). One specific possibility is for the contracts to transfer control to the buyer over operational and offer decisions, as in a tolling agreement, so that the seller cannot withhold from the spot market to support high forward prices. This outcome is closer to a "virtual divestiture" of the generating asset.

Application of Long-Term Forward Sales in Other Electricity Markets

Alberta began restructuring its electricity industry in 1996, part of which involved transitioning to a competitive wholesale market. Instead of taking the more typical approach of requiring generators to divest their assets, the Alberta government conducted an auction to sell the output from existing generating units to qualified buyers via Power Purchase Agreements (PPAs).[47] The series of auctions were held between 2000 and 2006.

[47] AESO (2006), pp. 12–13.

Under this plan, the owners[48] of each generating unit retained the physical asset. However, during the term of PPAs, the buyers were granted the rights to "market the output from that generating unit for the term of the [PPA] and to develop the unit's daily electricity offer strategy to the Power Pool.[49] After expiration of the contract, in many cases as long as 20 years, the offer rights to the generating unit would revert to the owner.

The terms of compensation were dictated by the PPA; in general, the owner was compensated through a combination of fixed, variable, and incentive payments[50] for capacity, energy, and maintenance. The compensation terms were intended to mimic the compensation that the owners would receive under traditional cost of service regulation.

A related approach was used in New Zealand. In 2009, a number of changes to the electricity system were enacted in the Electricity Industry Bill 2009.[51] In addition to a number of physical asset transfers between suppliers (related to the discussion in Section II.D.2.a), the reforms included requiring three dominant suppliers, Meridian Energy, Genesis Energy, and Mighty River Power to undertake "virtual asset swaps." These asset swaps were implemented using long-term (15 year) hedge contracts.[52] The New Zealand Electricity Authority found that the 2009 reforms successfully increased competition, significantly reducing the ability of generators to unilaterally and profitably raise prices.[53]

These contractual arrangements effectively sever the connection between the generation resource owner's dominant position and its ability and incentive to exercise market power in the energy market. Each PPA buyer (or virtual asset owner) becomes the residual claimant on his generator's cash flows, so as long as the generation owner is sufficiently compensated for its costs of operation, it has no incentive to withhold energy. As long as no PPA buyer is allowed to obtain a dominant position, structural market power is significantly reduced.

---

48 TransAlta, ATCO, and EPCOR; see AESO (2006), p. 12.

49 AESO (2006), p. 12.

50 These "Availability Incentive Payments" provided incentive for the owner to make the unit available to the buyer, where payments "flow to owners when unit availability is above target and to buyers when unit availability is below target." The incentive payments are based on a 30-day rolling average pool price and are split between on- and off-peak.

See MSA (2012), p. 5.

51 McSoriley, John (2009), p. 1.

52 Brownlee (2010).

53 New Zealand Electricity Authority (2014).

Implementation Issues

Addressing structural market power through forward contracting in the WEM would involve numerous important decisions. The PUO would have to work with stakeholders to determine the appropriate quantities and terms of contracts, and develop rules for auctioning the contracts, including participation rules and potential limits on contract prices.

Most fundamentally, the regulator would have to determine the contractual quantities of sales needed to reduce Synergy's net long positions. The appropriate quantity would depend on the productive capabilities of Synergy's physical assets and its existing contracts, including load-serving obligations that vary over time, which affect its net long position and consequently its incentive to exercise market power. The quantity also may depend on expected supply-demand conditions in the market that affect Synergy's ability to exercise market power. No contractual quantity would be perfect, however, since forward contracts usually specify fixed quantities that may not perfectly match and net out the supplier's time-varying net position.

It would also be necessary to determine what types of contract terms would work for both Synergy and for buyers in the WEM. Tolling agreements might seem to be ideal, since they transfer operational control and offer decisions to the buyer: the buyer basically rents the plant to burn its own fuel and market the power. This may not work well here, however, since Synergy already owns the coal and has long-term gas delivery contracts for its plants, so any tolling agreement would have to specify terms under which Synergy supplies the fuel.

As an alternative, more standard forward contracts for power might be simpler. A specified quantity of standard forward contracts could be auctioned to the highest bidders. Since forward contracts do not transfer operational control, however, Synergy would retain the ability to withhold from the spot market. As mentioned previously, it would be important to make the terms and conditions for offering long-term contracts sufficient to preclude sellers from benefitting from an inflated contract price that is reflective of their ability and incentive to exercise market power in short-term power markets.

Other auction rules would have to be developed to ensure that buyers do not amass enough supply to gain market power themselves.

Relationship to Behavioural Market Power Mitigation

Mandating forward sales by dominant suppliers can make the market more competitive. Since no set of contracts is likely to make electricity markets competitive in all circumstances, a behavioural market power mitigation mechanism would still be needed to address the inevitable temporal conditions where the electricity markets remain susceptible to exercises of market power.

Electricity markets have features that make them vulnerable to potentially substantial exercises of market power even for a relatively short duration, as a result of the very limited power storage capabilities, the highly inelastic short-term demand for electric power, and stochastic changes in demand and supply conditions (e.g., due to forced generating unit and transmission outages). As such, a dominant supplier would likely retain market power during peak demand conditions when supplies become tight (because forcing the supplier to sell enough blocks of power on a forward basis to eliminate their long position during peak conditions would cause them to be net short in other periods). Even moderately-sized suppliers can have market power during peak demand periods. And market power can become especially acute locally when transmission constraints protect local suppliers from competitors.

However, the instances of market power would become less frequent and less severe if the dominant supplier were forced to contractually sell some of its output under specified terms and conditions. Fewer instances of abuse would slip through the behavioural mitigation mechanism, and fewer offers would have to be investigated.

Recommendation for the WEM

We recommend improving the structural competitiveness of the market through long-term contracts if not physical divestiture, while retaining behavioural market power mitigation mechanisms. Such a combination would satisfy the criteria established in Section II.A.2:

- *Achieve SRMC-based energy prices*. It achieves the result of a competitive market by emulating one through contractual means, incentivising market participants to offer at SRMC most of the time; behavioural mitigation would help enforce SRMC-based offers the rest of the time.
- *Avoid false positives and egregious false negatives*. Both false positive and false negative behavioural mitigation would become less frequent than if relying solely on behavioural mitigation in a highly structurally uncompetitive market.
- *Cost effectiveness*. Structural improvements would reduce the number of cases the market monitor would have to investigate, compared to an approach that relies only on behavioural mitigation.

- *Transparency in how rules will be interpreted and enforced.* Transparency could be at least as good as under a purely behavioural approach.

The one criterion this approach does not meet is timeliness. It is not feasible to implement before the required July 2018 timeframe. Planning the PPA auctions is a process that is likely to take several years (see Implementation Issues above). Furthermore, it may be undesirable to attempt to conduct these auctions while market rules and conditions are in flux. Both buyers' and sellers' willingness to transact would be impeded by the market and regulatory uncertainty. We therefore recommend addressing incentives by pursuing forward contracting in the long-term, while still retaining behavioural market power mitigation mechanisms.

c. Semi-Regulated Forward Sales

Some market participants have suggested various forms of semi-regulated forward sales as approaches to market power mitigation. One specific suggestion, replacement of the STEM with financial instruments similar to those traded in the NEM, is discussed in detail in Section II.C.3; here, we discuss the general proposal that liquid forward sales can effectively mitigate market power.

In some markets, dominant suppliers offer "standard products" that they will be willing to both buy and sell from other market participants, either on a voluntary basis or due to mandates. Generally, the dominant supplier will be able to set the prices of these standard products, on the condition that the price at which they are willing to sell is no more than a fixed percentage higher than the price at which they are willing to buy. The standard products may be traded bilaterally or offered on exchanges. Mandates for dominant suppliers to sell or buy on an exchange are sometimes known as "market making" requirements.

In the following section, we discuss how this approach has been used to increase liquidity in forward markets in the New Zealand and United Kingdom energy markets, and whether this approach could serve as the primary mechanism for mitigating market power in the WEM.

Voluntary Market-Making in the New Zealand Electricity Market

In 2009, New Zealand had a fairly illiquid futures market. The Minister of Energy and Resources asked generators with over 500 MW of capacity to "put in place a market for trading standardised contracts, with low barriers and transaction costs, a clearing house, and market makers to provide liquidity" by June 2011.[54] The four largest generator-retailers[55] voluntarily met this request by signing annual, individual market-making agreements[56] with the Australian Securities Exchange (ASX) electricity derivatives market. These agreements include firm commitments to post the prices at which the companies are willing to both buy and sell quarterly baseload futures extended out at least three years, and monthly baseload futures extended out three months. These prices must be posted during one half-hour trading window each business day. The bid-offer spread has a maximum ceiling of 5 percent, and there are minimum trade volumes. In return for providing market-making services, the companies receive incentives from the ASX, such as rebates of trading transaction fees. This market-making activity has increased certainty around forward prices.[57]

Mandated Market-Making in the UK Electricity Market

In March 2014, new obligations to promote liquidity called "Secure and Promote" came into effect in the UK. The obligations introduced:

- "Supplier Market Access" rules, a set of minimum service standards for trading between small suppliers and the eight largest generators intended to make hedging products more available;
- A market-making obligation on the six largest vertically-integrated companies to promote robust reference prices for forward products; and
- A reporting requirement of day-ahead trading for the eight largest generators to secure near-term market liquidity.[58]

The market-making rules require the six largest vertically-integrated companies to post the prices at which they are willing to both buy and sell a range of specific products for delivery periods up to two years in the future. These prices must be posted during two one-hour trading windows each business day. The bid-offer spreads have maximum ceilings, ranging from one-half to one percent, depending on the type of product.[59]

---

54 New Zealand Electric Authority (2015), p. 9.

55 Contact Energy, Genesis Energy, Mighty River Power, and Meridian Energy.

56 Formally known as "Daily Settlement Liquidity Provider Agreements."

57 New Zealand Electric Authority (2015), pp. 12–13.

58 Ofgem (2015a), p. 5.

59 Ofgem (2015a), p. 24. Detailed information on Supplier Market Access rules may be found on pp. 33–36, and further description of the market-making may be found in "Table 2: Market-making Obligation–detailed rules" on p. 37.

Benefits of Market-Making Requirements

The market-making approaches described above are aimed at improving liquidity in the electricity hedge market, and both the New Zealand Electricity Market (NZEM) and United Kingdom regulators have described their benefits as such.[60] Liquidity is an important and necessary component in an efficient market. It improves "transparency around forward price expectations"[61] and ensures that "buyers or sellers that have found the products they need can then reliably make transactions promptly and at a cost-reflective price."[62]

However, even perfectly liquid forward markets are not sufficient to ensure competitive pricing where structural market power exists. Market-making approaches are not sufficient to mitigate market power when used alone. We have found no evidence that either the New Zealand Electricity Authority or the Ofgem believed that liquidity in forward markets would make it less likely that dominant players would exert market power in balancing markets, or lead market prices to approximate SRMC. (We mention this because some market participants in WEM questioned whether market-making approaches might obviate the need for market power mitigation).

In summary, liquidity-promoting mechanisms may complement other approaches to address market power, but there is no evidence that they ensure a well-functioning competitive market when used alone. We therefore rule out market-making requirements and related semi-regulated forward sales approaches as the primary market power mitigation mechanism for Western Australia. They do not satisfy the primary criterion described in Section II.A.2.

E. Long-Term Considerations

Some approaches to mitigating market power in the WEM are infeasible to implement by the time market reforms take effect in July 2018, but they should be considered as potential options in the longer term. Specifically, requiring dominant suppliers to divest assets (discussed in Section II.D.2.a) and mandating long-term forward sales (discussed in Section II.D.2.b) may be attractive options because they target participants' incentives and ability to exercise market power, significantly diminishing the need for active market power mitigation on an ongoing basis.

60 New Zealand Electric Authority (2015) and Ofgem (2015a).

61 New Zealand Electric Authority (2015), p. 7.

62 Ofgem (2015a), p. 7.

However, we do not believe either of these approaches, or any others, can yield a WEM that is fully competitive at all times. A medium-small supplier will be pivotal during tight market conditions, even if the market is structurally competitive much of the time. And locational market power may occur from time to time due to transmission constraints. In the extreme, one or more generators could be constrained-on for a long period of time, as was the case with Vinalco's Muja AB plant in 2014.

As a result, we believe there would still be a need for more direct offer mitigation even in a future WEM that is structurally more competitive.

III. Evaluation of the STEM and Alternatives

A. Introduction

The STEM is a centrally-administered day-ahead market where market participants can trade around their contractual positions without having to arrange a short-term bilateral trade and without waiting until real-time and being exposed to the volatility of the balancing market. The STEM provides liquid and competitive trading opportunities because all suppliers holding resources with capacity credits are obliged to offer their available capacity into the STEM, while recognising their bilateral transactions. Other supply offers and all buy bids are voluntary.

Some stakeholders have questioned whether there are effective alternatives to the STEM that would be less prescriptive and burdensome for suppliers. Particularly in the context of the energy market reform scheduled for July 2018, some stakeholders have questioned whether to continue, modify, or eliminate the STEM. The question is timely because the National Energy Market, with which the WEM will be aligning, does not have a STEM, so adding it will incur some cost. And if the STEM is continued, it might need enhancements to be compatible with the features of the new market, in concert with any changes to market power mitigation (discussed in the previous section of this report).

We have been asked by the PUO to evaluate whether to continue, change, or eliminate the STEM. To do so, we qualitatively assess the benefits and costs of the STEM and several alternatives that stakeholders have suggested or that other markets have implemented. Our assessment considers effectiveness in supporting a liquid, competitive market that helps minimise customer costs while still providing appropriate incentives to suppliers. We also consider implementation costs and feasible timing relative to the July 2018 inception date for the reformed energy market.

B. Purpose of the STEM

The primary purpose of the STEM is to provide market participants access to a liquid, competitive day-ahead market in which to trade around their bilateral positions and hedge their exposure to the volatile balancing market.[63] It achieves liquidity through a must-offer provision obliging resources holding capacity credits to participate. It achieves competitive pricing through the must-offer provision and an SRMC provision requiring resources' offers to reflect reasonable expectations of their SRMC.

A liquid and competitive STEM is an important source of day-ahead hedging for small retailers, who may face competitive disadvantages in the bilateral markets due to the WEM being structurally uncompetitive with one dominant supplier.[64] Furthermore, the STEM has lower credit requirements and transaction costs compared to bilaterals, removing barriers to entry and lowering costs for participants, particularly small participants. Ultimately, this means small retailers can better access competitive wholesale prices and compete down retail prices.

Some stakeholders have questioned, however, whether these benefits justify the costs. Direct costs include the $1.1 million cost of software upgrades to continue the STEM with the new market starting July 2018. Indirect costs include the burden on suppliers to formulate offers, and the risk of offers that fully reflect costs being deemed uncompetitive if SRMC provisions are interpreted too narrowly. Another possible risk to suppliers is that if they fail to submit STEM offers in time, they could incur capacity refunds (we understand that the PUO proposes to extend the STEM submission window by an hour to reduce that risk).

C. Options for the STEM or Alternatives

The options proposed by stakeholders and the PUO are:

1. Continue the STEM as-is, with the minor modifications proposed in the PUO policy paper;[65]
2. Continue the STEM but make it voluntary;

---

63 While the annual expected values of peak and off-peak STEM prices are typically within 10 percent of those of the balancing market, the balancing market prices exhibit 1.5-3 times the volatility. See Economic Regulation Authority (2015b), p. 21 and 35.

64 Small retailers procure nearly half of their energy in the STEM and heavily rely on it as a risk-management tool. See, Western Australia PUO (2016), p. 21.

65 These changes include eliminating Resource Plans and increasing the length of the submission window. See Western Australia PUO (2016a), p. 51.

3. Replace the STEM immediately with an AEMO-run exchange;
4. Eliminate the STEM completely and rely on the bilateral markets for day-ahead hedging; and
5. Other proposed options, such as Standard Products.

Below we describe each option and evaluate their costs and benefits. Our primary criterion for evaluating each option is whether it provides a liquid and competitive day-ahead market. Our secondary criteria are costs, implementation complications and risks, and implementation timing with respect to the July 2018 start date for the reformed energy market.

An important question that arises in assessing liquidity and competitiveness is whether it is necessary to impose must-offer and SRMC provisions directly in a day-ahead market—as in the STEM—or whether mitigating the balancing market suffices to discipline the day-ahead market. Our view is that the discipline imposed by the balancing market is helpful but imperfect because the two markets differ in timing, information, and volatility, among other differences. For example, if balancing market prices are expected to be $50 but highly volatile, buyers may not be willing to pay much more than $50 in the day-ahead market (and that disciplines suppliers), but if they are fairly risk-averse, they might be willing to pay $55. Suppliers with market power could then charge $55, even if a competitive price were closer to $50. The difference between $55 and $50 is not nearly as large as the difference between a totally unmitigated price and a competitive price, but it still matters. Our evaluation therefore favours approaches like the STEM that can enforce must-offer and SRMC provisions in the day-ahead timeframe, or at least achieve the same effect.

1. Continue the STEM

The first option we consider, consistent with the PUO's proposal, is to maintain the STEM almost completely as-is with the following minor modifications: (1) eliminate resource plans and (2) extend the STEM submission window by one hour.[66] Under this option, the STEM would be maintained with its existing must-offer and SRMC provisions.

The primary advantage of maintaining the STEM as-is would be that doing so would ensure all buyers continue to have access to a low-transaction-cost, liquid, and competitive market for day-ahead hedging. As mentioned above, this is particularly important for small retailers

66 Western Australia PUO (2016a), p. 51.

since the WEM is structurally uncompetitive with one dominant supplier. Additionally, the STEM is an established mechanism and so its integration into the AEMO's IT infrastructure is likely to be achievable by July 2018 without major cost or implementation risk. According to comments from AEMO, the risk of PUO's proposed STEM reforms failing to functionally align with its existing systems is initially low with a low risk for potential divergence. Furthermore, it classifies the impact of any such misalignment as low and the primary impact area of that misalignment as cost—suggesting that failing to meet the July 2018 implementation deadline with the STEM reforms is unlikely.[67]

As noted above, the cost to upgrade the STEM software so it is compatible with NEMDE systems is approximately $1.1 million.[68] This cost is likely very small compared to the benefits if the STEM helps make the entire market more competitive. To provide a sense of scale, the entire electricity market transacts well over a billion dollars per year.[69]

However, some market participants are concerned about the continuation of the STEM as-is. They contend that the STEM is unnecessary and that the must-offer and SRMC provisions of the STEM in particular may be heavy-handed, for example, forcing them at times to operate in a way that loses money. It is our view that these concerns can be addressed by clarifying the definition of "SRMC" to include all operational (not fixed) costs that a competitive supplier would consider in forming an optimal offer, as discussed in Section II.C.1 above. Adopting such an appropriately broad definition of "SRMC" could ensure that generators do not have to operate in a way that is expected to lose money, even with the must-offer provision, while still enabling a competitive STEM.

Additionally, a potential complication arises with constrained-off generation in the new market design. The balancing market is moving to the full security-constrained dispatch of the NEMDE, whereas the STEM will remain based on a classical economic dispatch engine. As a result, generators cleared in the STEM, where no transmission constraints are considered, could be constrained-off in the balancing market. Furthermore, the SRMC and must-offer provisions in the STEM may force a generator to make a day-ahead sale even if that generator anticipates being constrained-off in the balancing market. The constrained-off

---

67 See AEMO (2016a), Appendix B.3.

68 Based on advice from the PUO.

69 There are no readily available figures indicating transacted values (*e.g.*, PPA bilaterals—for both energy can capacity—are confidential). An indicative figure could be approximated by valuing capacity at the reserve capacity price and dispatched capacity at average balancing prices. For example; for the 2014/15 capacity year; the derived capacity value is $740M while the derived energy value is $809M making a total of $1,549M, according to the PUO.

generator would then have to buy energy in the balancing market to cover its day-ahead sale. This situation exposes suppliers to the volatile difference between STEM prices and balancing prices. To prevent this, the PUO will need to develop a solution, such as allowing suppliers who are likely to be constrained off to offer above their traditional SRMC.

Another fine point to consider is whether STEM prices will be consistent with those of the NEMDE-aligned balancing market. Under the proposed design, the STEM will continue to schedule only energy, rather than co-optimising energy and ancillary services, as NEMDE will for the balancing market. And yet, since ancillary services contracts will be eliminated, so will be the current provisions that inform the STEM about contractually-based capacity reservations for spinning reserves reducing the capacity available for energy.[70] As a result, the future design could overstate the amount of capacity available for providing energy in the STEM and could artificially depress prices relative to balancing market prices. On the other hand, STEM prices may be inflated relative to balancing prices by the absence of offers by intermittent generators, which are not subject to the STEM's must-offer rule. On net, if STEM prices turn out to be systematically above or below balancing energy prices, the PUO may need to develop a solution. One potential approach would be to allow SRMC-based STEM offers to account for the value of opportunities foregone in the balancing market.

2. Make the STEM Voluntary

A second option articulated in stakeholder comments to the PUO's market reform proposal, is to maintain the STEM without its must-offer provision for resources holding capacity credits.[71] Under this proposal, the SRMC provision of the STEM would remain intact, but participation in the STEM would be voluntary.

In our view, this option is unlikely to result in a liquid, competitive day-ahead market for hedging. Without the must-offer provision, there is no mechanism to prevent suppliers from withholding in the STEM. This could force buyers to choose between hedging at an elevated price or being exposed to volatile (but competitive) real-time prices. As such, it would not

70 Under the existing STEM design, units with contracted spinning reserve capacity that the system operator deems necessary for spinning reserve in the trading day is withheld from those units' STEM offers.

71 In the current STEM design, resources with capacity credits must offer that capacity in the STEM. Those that fail to make themselves available in a STEM interval without due cause, *e.g.*, an approved outage, could be subject to a refund of those credits. If STEM is maintained without a must-offer provision, all capacity credit refunds would be settled in the balancing market.

provide the main benefits of the must-offer STEM, yet it would incur the same implementation costs as the must-offer STEM. We therefore do not recommend it.

3. Replace the STEM Immediately with a Power Exchange

Another proposed option is to eliminate the STEM and replace it with an AEMO-run power exchange. Power exchanges are a relatively common approach to creating hedging opportunities complementary to the bilateral markets in electricity markets lacking an operator-administered day-ahead market. For example, short- and long-term hedging in the NEM and the New Zealand Electricity Market, which lack operator-administered day-ahead markets, is achieved via electricity products traded on the ASX. Similarly, market participants in the United Kingdom, where no operator-administered day-ahead markets exist, rely on exchanges such as APX Power UK, the Intercontinental Exchange (ICE), and N2EX UK for intra-day, day-ahead, and longer-term hedging products.

An AEMO-run power exchange could offer day-ahead hedging products that substitute for the STEM and additional products reflecting the hedging preferences of WEM participants. To create liquidity in the exchange, Synergy would be required to serve as a market maker, as in other exchanges with one or more dominant participants.[72] Under a market-maker provision, Synergy would be obliged to offer regulated quantities of specified exchange products, including, day-ahead hedging products, at a regulated price or with a regulated bid/ask spread.

An AEMO-run exchange with market-maker provisions for Synergy could work well to support a liquid, competitive day-ahead market. First, the AEMO could be given the authority to impose market-maker obligations, unlike the operator of an independently-run exchange, such as the ASX. Second, an exchange with a market-maker provision *and a tight bid/ask spread* can achieve the market power mitigation effects of the STEM by translating backwards the effect of a mitigated balancing market.[73] And third, an AEMO-run exchange

---

72 To promote liquidity for quarterly and monthly baseload futures, New Zealand Electricity products on the ASX have deployed market-maker provisions involving four of the five largest gentailers in New Zealand. However, owing to the ASX being an independent exchange, these provisions are entered into voluntarily via contracts between the ASX and the gentailers. See New Zealand Electric Authority (2015).

73 Enforcing a tight bid/ask spread would pressure Synergy to offer close to the expected price in the balancing market since doing otherwise would invite transactions that it would have to settle at a loss the following day. For example, if the expected balancing market price were $50 and the regulated bid/ask spread were $3 but Synergy tried to offer its energy at $60, market participants could opt to sell to Synergy at $57. Synergy would have to buy that energy day-ahead then re-sell

Continued on next page

could minimise transaction costs and credit requirements similarly to the STEM, and this would support market participation and liquidity.

An AEMO-run exchange could offer some advantages over the STEM. It could be used to provide a broader range of products. It could address some market participants' concerns regarding the burden placed on them by the STEM's must-offer provision, since participation would only be obligatory for the market maker. Another more subtle advantage is that transaction prices could reflect market participants' expectations of the effect of transmission and operating constraints that STEM does not account for, as discussed in Section III.C.1. This could improve the accuracy of forward price signals in the WEM.

However, implementing an AEMO-run exchange with market-maker provisions is not without challenges. The regulator or market monitor would have to determine how much quantity Synergy would have to offer for each hour, considering bilateral commitments, generator outages, transmission constraints and the economics of the fleet (*e.g.*, to avoid making Synergy sell output corresponding to the capacity of its peaking plants when such plants are not expected to generate in real time). They would have to choose an appropriate bid/ask spread that pressures Synergy to trade close to the expected balancing price (which is mitigated), but without excessively exposing it to money-losing transactions when it guesses the balancing price wrong. Making such determinations could be more risky and complex to design than just keeping STEM. Furthermore, there are cost and implementation uncertainties associated with establishing an exchange that may exceed those of the already-established STEM. Finally, it is unclear how this arrangement could be more effective than the STEM at offering liquid, competitive day-ahead hedging opportunities.

On balance, we see an AEMO-run exchange with market-maker provisions as a potentially viable alternative to STEM, but having failed to identify significant incremental benefits, we do not see the justification for the incremental complexity and risk.

4. Eliminate STEM and Rely on Bilateral Markets

Bilateral markets are a fundamental feature of the WEM and are the venue for the majority of the electricity transacted there on time periods longer than day-ahead. Recognising this prominent role of bilateral markets, several market participants support the elimination of the STEM contending that its functions can be accomplished by the existing structure of bilateral

---

Continued from previous page

it in the balancing market at $50, losing $7. The more prudent offer would be closer to $50 to avoid this expected loss.

arrangements and Standard Products.[74,75] Furthermore, these market participants maintain that eliminating the STEM may accelerate the creation of an independent exchange in the WEM, such as that run by ASX in NEM, that could further meet participant demand for hedging products. However, until such an exchange were to arise, market participants would be responsible for developing their own short-term hedging arrangements through bespoke bilateral transactions and existing Standard Products, which we discuss in the following section.

The main benefit of pursuing a purely bilateral market for hedging in WEM is cost savings: discontinuing the STEM eliminates the cost and effort associated with redeveloping the software to align with the NEM. Moreover, since moving to a bilateral market would not require updates to NEM software, it could be achieved by the July 2018 implementation deadline.

Similar to exchange prices, the bilateral prices can capture the impacts of market challenges not captured by the STEM, such as the constrained-off operation impacts discussed above. As with exchanges, this information can lead to price signals in the bilateral markets that can enhance operations and investment incentives. However, the formation of price signals that deliver such economic and operational efficiencies is predicated on the bilateral markets being liquid and competitive, which is unlikely to be the case in WEM due to Synergy's dominant position.

The major concern with relying on bilateral arrangements only is that bilateral markets would lack the must-offer and SRMC provisions central to the STEM. Lacking these provisions, the bilateral market may not provide the liquid and competitive day-ahead hedging opportunities that the STEM provides.[76] While a purely bilateral market's prices would be somewhat disciplined by a mitigated balancing market, the effect would not be perfect. A dominant participant would have the power to set the price for bilateral transactions above the expected balancing market price, which could result in risk-averse retailers incurring additional costs to achieve their desired day-ahead hedges compared to the STEM. Furthermore, market participants would face higher credit requirements and

---

74 See, for example, Alinta Energy (2016).

75 The Standard Products are quarterly and annual contracts for peak and flat (all hours) power that Synergy is obliged to offer in the WEM. Synergy must make available a minimum of 5 MW of buy and 5 MW of sell contracts per week at a bid/ask spread that does not exceed 20%. For a complete description of Standard Products, see State of Western Australia (2014).

76 See, for example, Community Electricity (2016), p. 1.

transactions costs in bilateral markets than they do in the STEM, further reducing liquidity in those markets. Finally, bilateral markets do not provide the price transparency that the STEM or exchanges can provide, increasing information discovery costs.

As a result of these shortcomings, we do not view moving to purely bilateral markets as a viable alternative to the STEM for providing liquid, competitive day-ahead hedging opportunities. It is our position that the loss of competitiveness and liquidity that may result from the dearth of options for imposing must-offer and market power mitigation in the bilateral markets is unlikely to be justified by the cost-savings associated with eliminating the STEM.

5. Other Approaches

Some participants have suggested that continued or enhanced Standard Products can make the STEM unnecessary. However, we see the Standard Products as a complement to the STEM, not a substitute, since it operates on a different timeframe. Standard Products are quarterly and annual and do not provide day-ahead hedging opportunities. In theory, the Standard Products could be expanded to include day-ahead products, but then the same complications would apply that we identified above regarding exchanges with market-maker provisions. Notably, even the current Standard Products suffer from low transaction volume, presumably because the regulator has not fully fine-tuned the bid/ask spread or other provisions.

Bibliography

Alberta Electric System Operator (AESO) (2006), *The Path to Transformation: A Case Study of the Formation, Evolution and Performance of the Alberta Electric System Operator*, May 2006, accessed 21 July 2016. Posted at http://www.aeso.ca/downloads/Path_to_Transformation_email.pdf

Alinta Energy (2016), "Comments on PUO Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms—14 March 2016," 27 April 2016, accessed 28 June 2016. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/energy-market-operations-and-processes-submission-Alinta-Energy.pdf

Assembly Estimates Committee B (2016), "Extract from *Hansard*," 24 May 2016. Posted at http://www.parliament.wa.gov.au/Hansard/hansard.nsf/0/ef292507bcd0ef3848257fc7002449cf/$FILE/A39+S1+20160524+p199b-209a.pdf.

Australian Energy Market Commission (2013), "Final Rule Determination: Potential Generator Market Power in the NEM", 26 April 2013.

Australian Energy Market Operator (AEMO) (2016a), "Response to Position Paper: Design Recommendations For The Wholesale Energy And Ancillary Service Market Reforms, 29 April 2016) accessed 28 June 2016. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/energy-market-operations-and-processes-submission-AEMO.pdf

Australian Energy Market Operator (2016b), "Review of Market Power Mitigation Measures in the Enhanced Western Australian Electricity Market: Input to a Brief," accessed 27 June 2016.

Australian Energy Market Operator (2016c), "Price Limits," accessed 02 August 2016 at http://wa.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Price-limits.

Australian Energy Regulator (AER) (2015), "State of the Energy Market 2015," accessed 5 July 2016. Posted at https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2015

Brownlee, Gerry (2010), Electricity Industry Bill Passes, Press Release, 23 September 2010, New Zealand Government, accessed July 25, 2016. Posted at https://www.beehive.govt.nz/release/electricity-industry-bill-passes

Community Electricity (2016), *Submission in* Response *to PUO Public Consultation: Position Paper—Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*, 27 April 2016, accessed 28 June 2016. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_

Market_Review/energy-market-operations-and-processes-submission-Community-Electricity.pdf

Economic Regulation Authority (ERA) (2015a), Notice – First Investigation into Vinalco's Pricing Behaviour, 30 October 2015, accessed 14 July 2016. Posted at https://www.erawa.com.au/cproot/13938/2/Notice%20-%20First%20Vinalco%20Investigation.pdf

Economic Regulation Authority (2015b), 2015 Wholesale Electricity Market Report to the Minister for Energy: Issues Paper (Appendices), November 2015. Posted at https://www.erawa.com.au/cproot/13961/2/2015%20WRM%20Issues%20paper%20appendices.pdf

Federal Energy Regulatory Commission (2014), *Price Formation in Organized Wholesale Electricity Markets, Docket No. AD14-14-000—Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets,* October 2014, accessed 25 July 2016. Posted at http://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

García, José A. and James D. Reitzes (2007), "International Perspectives on Electricity Market Monitoring and Market Power Mitigation," *Review of Network Economics* 6(3), September 2007.

Government of Western Australia (2016), "New reforms to WA wholesale electricity market," July 28, 2016, accessed August 2, 2016. Posted at https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/07/New-reforms-to-WA-wholesale-electricity-market.aspx.

Market Surveillance Administrator (MSA) (2012), Alberta Wholesale Market–A description of basic structural features undertaken as part of the 2012 State of the Market Report, 30 August 2012, accessed 25 July 2016. Posted at http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Basic%20Structure%20083012.pdf

McSoriley, John (2009), Electricity Industry Bill 2009, *Bills Digest*, Digest No. 1733, 15 December 2009, accessed July 25, 2016. Posted at https://www.parliament.nz/resource/en-nz/49PLLawBD17331/c55607ccb5542e0ee669f0fd8dbce6e4782ce161

Murray, Kieran, Toby Stevenson, Sally Wyatt, and Eva Hendriks (2012), *Market behaviour rules in New Zealand and internationally*, Sapere Research Group, 29 November 2012, accessed 7 July 2016. Posted at https://www.ea.govt.nz/dmsdocument/14283

Nahan, Hon. Mike (2015), *Government energised for electricity reform,* Government of Western Australia Media Statement, 24 March 2015. Posted at https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/03/Government-energised-for-electricity-reform.aspx

New Zealand Electricity Authority (2014), "Progress with Improving Electricity Industry Performance," 1 April 2014, accessed 25 July 2016. Posted at http://www.treasury.govt.nz/publications/media-speeches/guestlectures/pdfs/tgls-carlhansen-slides.pdf

New Zealand Electric Authority (2015), *Hedge Market Development: Enhancing trading of hedge products*, Consultation Paper, 1 May 2015, accessed 20 July 2016. Posted at https://www.ea.govt.nz/dmsdocument/19441

Ofgem (2004), *Competition Legislation Competition Act 1998–Application in the Energy Sector*, 11 August 2004, accessed 11 July 2016. Posted at https://www.ofgem.gov.uk/publications-and-updates/competition-act-1998-application-energy-sector

Ofgem (2014), *Enforcement Guidelines*, 12 September 2014, accessed 11 July 2016. https://www.ofgem.gov.uk/sites/default/files/docs/2014/09/enforcement_guidelines_12_september_2014_published_version_1.pdf

Ofgem (2015a), *Wholesale Energy Markets in 2015*, 9 September 2015, accessed 5 July 2016. https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/wholesale_energy_markets_in_2015_final_0.pdf

Ofgem (2015b), *Wholesale Power Market Liquidity: Annual Report 2015*, 9 September 2015, accessed 6 July 2016. Posted at http://www.ofgem.gov.uk/sites/default/files/docs/2015/09/wholesale_power_market_liquidity_annual_report_2015_0.pdf

Ofgem (2016), "The GB electricity transmission network," accessed 5 July 2016. Posted at https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network

Pickles, Saskia (2015), "Synergy entity's pricing breached rules: ERA," *Western Australia Business News*, 3 November 2015, accessed 7 July 2016. Posted at https://www.businessnews.com.au/article/Synergy-entity-s-pricing-breached-rules-ERA

PJM (2011), "No-Load Definition: Educational Document," PJM DOCS# 631734, Rev 2, 2011, accessed July 29, 2016. Posted at https://www.pjm.com/~/media/committees-groups/subcommittees/cds/20110321/20110321-item-03b-educational-paper-for-no-load.ashx

Reitzes, James D., Johannes P. Pfeifenberger, Peter Fox-Penner, Gregory N. Basheda, José A. García, Samuel A. Newell, and Adam C. Schumacher (2007), *Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets*, The Brattle Group, 14 September 2007, accessed 7 July 2016. Posted at http://www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf

State of Western Australia (2014), *Electricity (Standard Products) Wholesale Arrangements 2014*, 19 May 2014. Posted at http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3911638a33eff5b6457b2ce248257cf30029ad85/$file/1638.pdf

Synergy (2016), "Who we are," company website, accessed 14 July 2016. https://www.synergy.net.au/About-us/Who-we-are,

Twomey, Paul, Richard Green, Karsten Neuhoff, and David Newbery (2005), "A Review of the Monitoring of Market Power: The Possible Roles of Transmission System Operators in Monitoring for Market Power Issues in Congested Transmission Systems," *Journal of Energy Literature* 11(2), 2005. Posted at http://web.mit.edu/ceepr/www/publications/reprints/Reprint_209_WC.pdf

Western Australia PUO (2014), *Electricity Market Review: Options Paper*, December 2014. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Electricity-Market-Review-Options-Paper-December-2014.pdf

Western Australia PUO (2016a), Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms, 14 March 2016. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Position-paper-Energy-Market-Operations-and-Processes.pdf

Western Australia PUO (2016b), *Final Report: Reforms to the Reserve Capacity Mechanism*, 7 April 2016. Posted at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Reforms-to-the-Reserve-Capacity-Mechanism-Final-Report.pdf

Appendix A. Concepts for Screening Analyses

As discussed in Section II.C.2, *ex post* mitigation starts with screens to identify possible violations that warrant further scrutiny. The two basic types of screens will:

1. Identify when market power exists, by defining the relevant market and analysing market conditions and supplier positions; and
2. Identify when a supplier's offers exceed SRMC.

The following concepts could be incorporated into these two types of screens to detect the exercise of market power.

1. Identify When Market Power Exists

Any test for the presence of market power starts by defining the relevant market. Since electricity is difficult to store, and many users have little ability to substitute across time, each trading period can be considered a separate relevant market. In addition, transmission constraints may from time to time preclude the free trade of energy across different areas. In these cases, suppliers who do not generally possess market power may enjoy locational market power. The market monitor should separately evaluate each "relevant product and geographic market" and use structural tests to determine whether each market and trading period of interest presents a potential market power concern.

In other wholesale energy markets, various market concentration and "pivotal supplier" tests are used to assess whether the market structure is conducive to exercises of market power such that *ex ante* mitigation efforts are needed. Although other aspects of *ex ante* market power mitigation are not suitable for WEM, structural tests such as these have proven to be reliable screens for market power across markets with a variety of characteristics and operating rules. Similar tests can be useful as screens in *ex post* efforts to assess and sanction exercises of market power.

While measures of market structure, such as the Herfindahl-Hirschman Index (HHI) of market concentration, are relatively crude mechanisms for assessing whether significant exercises of market power are possible, the various pivotal supplier tests used in regional wholesale electricity markets can provide more targeted information about the time periods and locations where firms may have the ability to significantly elevate market prices.

A pivotal supplier is a market participant whose generation is necessary to meet market demand. Due to constraints such as capacity limitations affecting other market participants, transmission constraints, or other structural issues, the residual demand facing the supplier is highly inelastic (price-insensitive), so the pivotal supplier has a strong incentive to exercise substantial market power. Pivotal supplier screens test for situations when a single supplier may be pivotal, or a small group of suppliers are "jointly" pivotal.

When deciding whether to use a single-pivotal-supplier, two-pivotal-supplier, or three-pivotal-supplier test, the market monitor must consider the risks and costs of both under-identifying and over-identifying a supplier's ability and incentive to exercise market power. Single-pivotal-supplier tests are conservative in that they fail to identify situations where a supplier is not fully pivotal (*i.e.*, the market can meet load without relying upon that supplier) but nonetheless has both the ability and incentive to raise prices by economically withholding supply (*e.g.*, through above-cost offers for the use of some of its resources). By contrast, the three-pivotal-supplier tests may yield more "false positives"—that is, it may "flag" circumstances as potentially problematic where there is not an incentive or ability to exercise substantive market power.

When used in the context of *ex ante* mitigation, false positives present a significant problem because the mitigation is applied automatically and can directly affect market outcomes. By contrast, when used with *ex post* mitigation, screens that yield "false positives" are less problematic because they merely identify situations that require further investigation. In this context, effective *ex post* enforcement may lean toward the application of broader screens, since the investigation process can be used to focus punishment only on those cases where there is sufficient evidence that market power actually has been exercised. As long as the pivotal supplier test is used in conjunction with other screens, and the cost of (preliminary) investigation in the case of false positives is not too high, this may be more desirable than a test that fails to sufficiently identify significant market power concerns.

The residual demand test is another market power screen, one which identifies conditions where there is both an ability and incentive to exercise market power.[77] Each supplier's residual demand curve is calculated by subtracting the offer curves of all other suppliers from the total demand curve. The "elasticity" of this residual demand curve, particularly evaluated around the market price, provides a measure of the market power held by each supplier in that period. It can be directly used to assess the supplier's incentive to raise price above its SRMC.

---

77 Twomey, *et al.* (2005).

Small suppliers frequently face high residual demand elasticity, such that there is not much incentive for the supplier to attempt to achieve a price increase, due to the relatively large share of sales it would lose as a result. By contrast, pivotal suppliers face a highly inelastic residual demand at some point, demonstrating that they have an ability to significantly increase price by withholding output. The residual demand test can reveal cases when a supplier may not be strictly pivotal, but still faces a situation where it can induce a large increase in price without sacrificing a large share of sales in the process.

For monitoring purposes, a supplier's residual demand curve can be calculated using the same information available to the market operator for balancing purposes. The market monitor can choose a threshold elasticity level that balances the concerns for false positives and false negatives. The pivotal supplier test and the residual demand test, when used together, will provide the market monitor excellent information about the market conditions and degree of market power in each relevant market.

2. Identify When a Supplier's Offers Exceed SRMC

As discussed in Section II.C.2, generators face various uncertainties at the time they form their offers. The market monitor has to recognise that when reviewing offers, along with another set of uncertainties: the market monitor has less information about a generator's actual costs than they do. Even if each generator submits information on its unit characteristics and fuel contracts, fuel costs are particularly challenging for the market monitor to estimate. Fuel contracts can be complicated and not transparent, and secondary spot markets are also not transparent in Western Australia; these markets determine the opportunity cost of fuel under a take-or-pay contract. In light of these endemic uncertainties, we recommend two complementary approaches to screening for uncompetitive offers.

The first and most obvious approach is to compare actual offers to benchmark offers reflecting the cost information the market monitor has about the unit characteristics and fuel contracts and markets. Startup costs have to be amortised over an expected quantity of output, which can be estimated using the actual dispatch. A more sophisticated approach would estimate the optimal offer a competitive supplier could make, given its costs and market prices—this approach is better because it avoids the self-fulfilling prophecy where an aggressive generator offers at a high price consistent with very little dispatch, and then the high offer price prevents it from being dispatched.

An alternative is to set the reference level based on a prior period, such as a shoulder period, during which the market monitor believes competitive conditions were more prevalent. This has the advantage of being the least informationally intensive method of setting the reference price. However it may be less accurate since conditions affecting costs can change.

In both cases, a "reasonableness" standard has to be applied, recognising that any particular offer might differ from the market monitor's competitive benchmarks. Identifying an offer slightly above the benchmark in a few trading intervals should be excused. We would recommend flagging only offers that substantially exceed benchmarks for a single or a few trading intervals, or a pattern of smaller discrepancies that occur frequently.

These tests are most meaningful when applied in combination with the market power screen described above. For example, if offers tend to increase when the market power screens are flagged, this may be a strong indicator of the exercise of market power.

The market monitor should clearly define the approaches used to screen for abuses of market power, and yet may wish to withhold information about the specific thresholds used to trigger questioning or investigation from market participants. Clearly defining the maximum allowable deviations from SRMC-based pricing, sometimes known as a "bright line test," may enable dominant suppliers to safely exert a limited amount of market power, which is undesirable. Tests that are well defined but have a hidden or fuzzy threshold may be more likely to incentivise participants to fully comply with the spirit of the regulation and price at their true SRMC.