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Seed Advisory

The Five Minute Settlement Rule Change Proposal

Review of the Australian Energy Market Commission's Directions Paper

29 May 2017

Contents

1. Executive Summary

1.1. What we have been asked to do

In reviewing the Australian Energy Market Commission's (AEMC) arguments in relation to Sun Metals' Rule Change Proposal to align current 30 minute settlement periods with five minute dispatch intervals, among other issues we have been asked to consider:

- The extent to which the underlying assumption (that alignment of dispatch and settlement intervals at 5 minutes will lead to more efficient market outcomes), is reasonable in the context of the National Electricity Market (NEM)
- The factors that should be considered in determining/comparing market outcomes under five and 30 minute settlement
- The appropriate methodology for measuring any differences in efficiency outcomes under the status quo compared to the proposed rule change, as well as the inherent complexities and limitations of undertaking such an assessment
- Whether, of the international examples cited by the AEMC where dispatch and settlement intervals (real-time) are in the process of being aligned, the rationale for alignment, the underlying issues driving alignment, and materiality of any market inefficiencies identified (where already quantified/qualified) provide guidance to the Australian experience
- The merits of the AEMC's proposed assessment framework
- Whether a cost benefit analysis is useful in any decision making framework used to assess the merits of the proposed rule change, including any limitations to such analysis
- The key underlying assumptions likely to determine the magnitude of any ongoing costs and benefits if 5 minute settlement is introduced, as well as the likely timing of any such costs and benefits
- The key scenarios and sensitivities worth exploring when considering any ongoing costs and benefits that are likely to eventuate if the rule change is implemented.

The Scope of Work is given in full in Appendix A.

1.2. How we've approached this

We initially considered the issues raised by Sun Metals' Rule Change Proposal following the release of the Consultation Paper[1] and subsequent Working Paper[2]. To inform our views we commissioned some analysis looking at dispatch interval prices for the New South Wales, Queensland, South Australian and Victorian wholesale electricity markets for the period from the beginning of 2010 to mid-2017. Summaries of our key analyses are given in Appendix B, and the results of those analyses are referred to throughout this paper.

In approaching the Scope of Work, we have also considered arguments relied on in previous Rule Change Determinations by the AEMC and their application to the issues the basis of Sun Metals' Rule Change Proposal. Although previous analytical and decision making frameworks relied on by the AEMC have no formal status, the AEMC has

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[1] AEMC, 2016, Five Minute Settlement Consultation paper, May

[2] Five Minute Settlement Working Group, 2016, *Working Paper No. 1: Materiality of the Problem and Responsiveness of Generation and Load*, Australian Energy Market Commission, October

developed and applied a consistent approach to the evaluation of rule change requests under the National Electricity Objective (NEO), which it describes in Section 2 of the Directions Paper.[3] From time to time the AEMC has described the extent of its discretion in relation to Rule Change proposals, including the limits of its power to make a more preferable rule "where it is satisfied that, having regard to the issues raised by the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO than the proposed rule."[4] Market participants, particularly those that may incur significant costs or experience significant changes to their businesses as a result of the AEMC's decisions are entitled to expect some consistency from the AEMC, even as external conditions ("the context") change. Our findings suggest significant commonalities between the issues underlying Sun Metals' Rule Change Proposal and those issues reviewed by the AEMC in its consideration of the Bidding in Good Faith Rule Change Proposal. On this occasion, however, the Commission's approach significantly differs from the approach taken in response to that Rule Change Proposal, overlooking the regional concentration of the issue and shifting its ground towards an analysis of the apparent inefficiencies of high Dispatch Interval 1 (DI 1) prices as the basis for a market-wide, forward looking proposal. In its review of the available evidence and in shifting the basis for its direction, the AEMC's current view of the issues appears not to correspond with its previously expressed views about the scope of its latitude in relation to amending rule change proposals in favor of a more preferable rule.

Finally, relying on the AEMC's analysis of the issues underlying Sun Metals' Rule Change Proposal we've considered what would be required to provide a robust case in favor of adopting the Commission's current direction. Work undertaken for the Commission suggests a significant loss in the ability to provide cap contracts as a direct result of moving to five minute settlement. The expected gains in efficiency rely on this gap being filled. We've considered ways in which the AEMC could provide additional support in favor of its argument that the gap can be filled, and filled in a timeline consistent with the current proposed transition period.

1.3. Our findings in brief

1.3.1. What our results suggest

The results of our analyses are similar to the AEMC's. We have not identified easily observable relationships between underlying demand or supply changes and high price Dispatch Interval 6 (DI 6) price events, even when restricting our sample to a small, high price group of DI 6 events. Our findings suggest the issues are not the result of (an absence of flexibility in responding to) sudden changes in demand or supply. The DI 6 price events captured by our analyses disproportionately occur in Queensland. Additional analyses suggest continuity between these events and the events examined as part of the earlier Bidding in Good Faith Rule Change. Changes to the National Electricity Rules (the Rules) were introduced in late 2015 with effect from 1 July 2016.[5] The AEMC's Directions Paper on the Five Minute Settlement Rule Change proposal appears to argue that the events the subject of Sun Metals' Rule Change Proposal have now been addressed.[6] Its

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[3] Australian Energy Market Commission, 2017, *Directions Paper: Five Minute Settlement Rule,* 11 April

[4] AEMC, 2017, p. 7

[5] AEMC 2015, *Bidding in Good Faith, Final Rule Determination*, December 2015

[6] AEMC, 2017, pps 17-18

focus has shifted to the incidence of DI 1 intervals higher than subsequent dispatch interval prices in the same settlement period.

Our results raise a number of issues in relation to the AEMC's preference to make a more preferable rule, introducing five minute settlement for all market participants after an appropriate transition period.

- First, if the behaviour of DI 6 and DI 1 prices is not the result of sudden brief changes in demand or supply, then the proposed changes are not adequately justified. The efficiency gain resulting from the increased participation of flexible generation technologies to address rapid changes in demand or supply is unlikely to materialise. Although we have not analysed the relationship between high DI 1 prices and demand, on the basis of our analysis of DI 6 prices and demand we are sceptical that any relationship can be demonstrated for DI 1 prices.
- Secondly, in previous Rule Change proposals the AEMC has declined to make significant changes to the Rules where an issue appears to be local in its application, or a response to the outworkings of industry structure.[7] High price DI 6 events in Queensland are disproportionately represented in our results, reinforcing the AEMC's early view about the geographic distribution of the issues raised by the Rule Change proposal. In the light of this finding, we would have anticipated the AEMC treating this issue in a similar way to its approach to earlier rule change proposals addressing regional markets with very different characteristics.
- Finally, if the issue Sun Metals' Rule Change Proposal is specifically intended to address is now in the past, on what basis is the AEMC proceeding with the Rule Change?[8]

1.3.2. Efficiency test

The AEMC's arguments about the inefficiency of the current arrangements and the benefits from eliminating the inefficiency rest heavily on the two cases it identifies where it argues efficiency is reduced by averaging dispatch interval prices to calculate the settlement price. In the first case, where prices *increase* across the settlement period, the efficiency loss is relatively straightforward to identify – both consumers' and available but not participating producers' outcomes are worse than they would otherwise have been.

However, the AEMC's direction now appears to rely on a much less obvious case of inefficiency, bolstered by an argument about the barriers to emerging technologies from the current arrangements. In this case, where the average price *falls* over the settlement period as a result of the averaging process, the efficiency loss is closer to an opportunity loss than a cost to all customers.

- Customers' actual costs, whether market or retail customers, depend on the outcome for prices over the settlement period. Market customers with the capacity to respond to dispatch interval prices pay higher prices in DI 1 than would otherwise have been the case, but other market customers' outcomes depend on the trajectory of prices across the settlement period. Retail customers' prices, including the cost of caps which represent a significant element in retail costs, are based on settlement prices.

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[7] Most recently, AEMC, 2015, p (*v*) and throughout

[8] Our results show only weak support for this proposition, see Appendix B. In any event, given the relatively short time that the amended Rules have had effect, and our results that suggest events are more frequent over the summer, the AEMC's view may be premature.

- In the immediate term, those participants not dispatched in a high price DI 1 as a result of their pricing decisions relative to their competitors suffer a loss of income.
  - Generators' behaviour, whether bidding a high price in DI 1 or "piling in" in subsequent dispatch intervals resulting in the price falling, may not be irrational.
  - A generator may bid strategically in the face of an expected decline in prices over the settlement period with the objective of achieving (something closer to) the desired price. This behaviour is not irrational from the generator's perspective, and from a wider market perspective may not be inefficient depending on the level of prices sustained over the longer term.
  - Alternatively, in reducing the price over the settlement period by increasing their load offered at lower prices, generators may be knowingly defending sold option positions (settled off 30 minute prices), or acting on portfolio-wide strategies, where those portfolios include sold retail load. If generators are acting on some maximising function, then although high DI 1 prices may result in some loss to highly responsive market customers where the price falls in subsequent dispatch intervals, generators' strategies result only in a loss considered in isolation from other factors governing their behaviour.
- Over the medium to longer term, potential participants that refuse to enter the market presumably do so based on a view that they may fail to make the return necessary to justify their investment.
  - Typically this would be regarded as an appropriate decision, considered either from the individual's perspective or economy-wide. The exception would be where the participants' views of the risk to their investment are based on misleading information, for example, on an expectation of high volatility where actual volatility is likely to be lower, or vice versa.
  - It's unclear why this is considered to be a specific efficiency loss in the AEMC's analysis, unless it's demonstrably the case that transitory high DI 1 prices are the result of rapid changes in demand and/or supply.

The AEMC's efficiency argument rests heavily on this case, which it then extends by effectively arguing that the current dispatch interval price/settlement price mismatch is a barrier to market transformation in response to emerging technologies.

While as a high level principle the assumption that any misalignment between dispatch and settlement intervals is inefficient may be sound, in expressing a preference in favour of alignment, the AEMC needs to identify the extent of the current inefficiency and the benefits of the proposed change. This requires the AEMC to:

- Discuss what level of variation between dispatch interval prices is efficient, and what level is inefficient
- Identify the likely reduction in volatility from dispatch interval to dispatch interval resulting from the alignment of dispatch and settlement
- Identify the ways in which different classes of electricity market participants – generators, intermediaries and customers – experience the benefits of reducing the existing inefficiency and whether, in considering different classes of participants the net benefits or reducing the inefficiency are likely to exceed the costs.

The AEMC's discussion does not address these questions, except to the extent that new investment in flexible, responsive generation is expected to reduce price volatility from dispatch interval to dispatch interval to some more acceptable level. No insight into the anticipated level of volatility from dispatch interval to dispatch interval under the proposed Rule Change is provided, a critical question in considering this Rule Change proposal, and an equally critical consideration to those parties considering investment to supply flexible responsive services to the market.

1.3.3. Benefits and costs

We understand and, to a point, accept the arguments against detailed modelling of the NEM with/out five minute settlement: the range and contestability of the assumptions that it would be necessary to make is so wide that agreement on an acceptable set of assumptions is unlikely. However, there are key areas where some form of analysis is not only feasible but, given the Commission's concerns about key elements of the outworkings of this proposal, highly desirable.

The key arguments in favour of a shorter settlement period are:

- the improved efficiency of the spot market resulting from improved price signals, whether considered from a load perspective or a generator's perspective
- the subsequent investment directed at providing the required responsive generation.

To encourage the necessary investment, the price signal needs to be both sufficiently high and persistent. To the extent that the events the price signals address are themselves transitory, the available price signals are unlikely to meet the persistence test.

Even if there are, or there will be as result of the growing penetration of renewable generation sufficient and sufficiently high transitory price signals to signal the requirement for new investment, these conditions may not be sufficient for new investment to occur. Whether, when, where and on what conditions the necessary investment is likely to occur should be pursued by the AEMC in support of its current direction, even if only in the form of plausible scenarios about the future path of required investments. The likely timing of any investment is a key issue: Energy Edge's analysis suggests a loss in the quantity of available cap contracts on the introduction of the Rule Change as a result of the inability of existing participants to cover their shorter spot price exposure.[9] In the absence of additional investment by incumbent generators, or new entrant market participation on a scale commensurate with Energy Edge's findings the Commission's own proposed evaluation framework[10] will fail the tests set for price risk exposure and efficient risk allocation via contracting.

Timing is also important in weighing future benefits against current costs: future benefits need to be considerable to outweigh costs incurred in the immediate or very short term.

The AEMC makes relatively few comments on the role of uncertainty in its analysis, except to the extent new entrant generators suffer some uncertainty in relation to their potential earnings. In the current context, however, wider uncertainties relating to the future structure of the energy market may affect participants' willingness to undertake any new investments, even when the conditions for profitable participation exist.

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[9] Energy Edge, 2017, *Effect of 5 Minute Settlement on the Financial Market*, March
[10] Australian Energy Market Commission, 2017

Finally, there's no discussion in the Directions Paper of the implications for energy productivity or dynamic efficiency – implementing the Rule Change requires higher investment and additional costs, but, assuming the observed dispatch interval volatility is the outworking of more frequent transitory effects on demand or supply, customers will experience some increase in their costs with no obvious change in energy services.

1.3.4. International experience

The AEMC cites studies suggesting a movement towards real time pricing in a number of electricity markets internationally. The markets cited do not support the Rule Change under consideration, whether considering the definition of efficient combinations of dispatch and settlement interval or the rationale for the shift from the current arrangements to alignment of dispatch and settlement. The **New Zealand** electricity market is moving from the longest gap between dispatch and settlement among developed countries' electricity markets – around two days – to the current Australian alignment (five minute dispatch and 30 minute settlement) to support the development of derivative markets, having considered but rejected a shift to the 5/5 model.[11] The **Federal Electricity Regulatory Commission's** (FERC) decision's key focus is aligning the dispatch and settlement characteristics of energy, transmission and other service markets (the equivalent of FCAS markets) with the objective of, among other things, reducing the uplift (compensation) and ancillary service payments resulting from a lack of alignment across all three markets.[12] **Alberta** announced in 2016 its shift to capacity pricing; previous discussions of the alignment of dispatch and settlement have been overtaken by this decision and had earlier been downgraded from an action item to an element of longer term IT planning[13].

[11] Electricity Authority of New Zealand, 2016, *Real Time Pricing Options: Decision Paper*, August 2016

[12] Federal Energy Regulatory Commission, *Docket No. RM15-24-000; Order No. 825: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, June 16, 2016

[13] Alberta Electricy System Operator. (2015) *Stakeholder Comment and AESO Replies Matrix AESO Consultation – 2015 Budget Review Process: Meeting September 22nd - AESO's Preliminary List of 2015 Business Initiatives*

2. Market outcomes under the Five Minute Settlement Rule Change proposal: Issues

2.1. Background

The Scope of Work (Appendix A) asks us to look at:

- The extent to which the underlying assumption (that alignment of dispatch and settlement intervals at 5 minutes will lead to more efficient market outcomes) is reasonable in the context of the NEM

In reviewing the Working Paper[14] and the Directions Paper in relation to the Five Minute Settlement Rule Change Proposal[15], we've approached this question by asking whether we agree with the AEMC's problem description.

In discussing participation and price setting in the spot market, at times the AEMC conflates the separate processes of bidding and generating, particularly for flexible generation technologies, raising questions about the way in which the current inefficiencies are described, as well as the delivery of future efficiencies important to the AEMC's justification for the Rule Change.

How the spot market operates now and could be expected to operate in the future are key questions for this Rule Change. Different explanations for generator behaviour have different implications for the likely market outcomes if the Rule Change is to be adopted. The AEMC's analysis of generator behaviour takes no account of the level of integration across spot and retail markets, or the implications of different portfolio structures for bidding behaviours, either under the existing spot market rules or amended rules. In not exploring the requirements for successful participation in the wholesale market, the AEMC arguably overstates the likelihood of new, flexible generators' successful market participation where required to compete with existing generation.

In the following sections we look at the way in which the AEMC's papers describe wholesale market participation and the processes of bidding and generating, drawing on evidence from the AEMC's discussions. We also review the results of our work, detailed in Appendix B. Finally, we speculate on the extent of volatility in a market with aligned dispatch and settlement intervals.

2.2. The alignment of dispatch and settlement intervals: the AEMC's case for increased efficiency

The AEMC's broad argument for alignment between dispatch and settlement intervals assumes that any misalignment between dispatch and settlement intervals is inefficient where participants receive/pay an average price for the settlement period rather than the price relevant to the dispatch interval in which the participant generated or consumed electricity.

The AEMC discusses two cases: the price increases over the settlement period as result of rising dispatch interval prices; and the price falls over the settlement period as a result of falling dispatch interval prices. The first case is the basis for Sun Metals' Rule Change

[14] Five Minute Settlement Working Group, 2016
[15] AEMC, 2017

proposal. Sun Metals' specific concern is their inability to respond to the averaging up of prices over the settlement period, notwithstanding their own very rapid load response capability. The second case, where prices fall over the settlement period, is not the basis for Sun's proposal, although it has assumed more significance in the AEMC's discussion of the Rule Change proposal and the related efficiency issues.

2.2.1. Prices increase over the settlement period: Efficiency loss

In the case where prices increase across the settlement period, the efficiency loss is relatively straightforward to identify – both consumers' and available but not participating producers' outcomes are worse than they would otherwise have been. Efficiency, considered as encompassing all customers' welfare, would be improved by reducing the efficiency loss. It does not necessarily follow from this statement about efficiency that: the frequency with which a high dispatch interval price giving rise to these losses would be reduced by aligning dispatch and settlement intervals; or, that the efficiency loss identified in relation to the current arrangements is best addressed by aligning the dispatch and settlement intervals.

Although arguing that the incentive to behave in this way has been reduced or removed as a result of changes to the Rules relating to rebidding, the AEMC identifies the sources of inefficiency as:

- The higher price paid by spot-exposed loads and customers, relative to an efficient DI 6 price, whatever that level should be
- The flow through of higher average settlement prices to contract prices and all customers
- The risk that flexible generation technologies will refuse to bid into the market in response to anticipated price spikes where the price spike occurs late in a settlement period *and* the flexible generator expects that it will be unable to achieve its target price for its dispatch as a result of its knowledge of the prior dispatch prices and the averaging process.
  - Given the current market design, as the AEMC recognises, this risk is symmetric: if the flexible generator's revenue targets are materially higher than other generators' targets, then the flexible generator is unlikely to realise its revenue targets if the price is averaged down over the settlement period or averaged up, but only briefly late in the settlement period.

The AEMC's analysis begs the questions of how the efficient DI 6 price is determined and the frequency of high price dispatch intervals in the absence of the averaging incentive described. In ignoring these questions, it assumes that there will be an increase in the efficiency arising from a reduction in the first and second sources of inefficiency, without demonstrating the proposition.

In describing the third potential source of inefficiency, the AEMC appears to be thinking about the requirements of a particular type of flexible generation technology – capable of short term, intensive responses and relatively expensive to operate – as well as a temporary price spike. However, for this loss to be realised, then there should be an unmet need for the services these technologies can provide, which the AEMC asserts but fails to demonstrate.

2.2.2. Prices fall over the settlement period: Efficiency loss?

Where the average price falls over the settlement period as a result of the averaging process, the efficiency loss may be closer to an opportunity loss than a cost to market participants and customers as a whole. This case, on which the AEMC's argument relies, is the more interesting because it is considerably less obvious than the preceding case.

Where the average price falls over the settlement period as a result of the averaging process, if generators reduce their price to ensure dispatch on the assumption that the early high dispatch price signalled high demand and are mistaken about the duration of the high transitory demand event, then bidders in later dispatch intervals receive a lower price than in the first high price dispatch intervals, suffering an opportunity loss relative to their expectation. Customers' gains or losses depend on the outcome of the settlement period. The averaging process may deliver lower prices over the settlement period for market exposed customers; in this case, reducing output in the first dispatch interval in the expectation of consistent higher prices would represent a welfare loss. Generators' and customers' losses could also be attributed to failures to forecast or anticipate the subsequent reaction of other market participants.[16]

In the Directions Paper, the AEMC uses descriptions that effectively combine the processes of generator bidding and dispatch. One example among a number occurs in Section 3.3.1, when the Directions Paper says in relation to the potential for high DI 1 price outcomes to give rise to inefficient outcomes averaged over the settlement period:

> ".... the generation can be occurring up to 25 minutes after it is required by the power system. Further, to maximise [individual generators'] share of the initial spike, [generators] are likely to bid prices well below the short run marginal cost of generation to ensure being dispatched."[17]

We assume the reference to generation occurring after it's required is not a literal description, but a normative description about the desired price and the price outcome for DI 1: "If more generation had been bid into DI 1, the price achieved would have been lower than the price that resulted." Given the market design, this would generally be true, if not particularly insightful. When is this result *inefficient*?

- From a market perspective, it's *inefficient* if the high DI 1 price is associated with an unpredicted increase in demand, assuming that better information would have resulted in a response from customers withdrawing demand or additional generation being scheduled. Less demand could have been serviced more cheaply provided customers are able to respond to a changed forecast, or prices need not have been as high provided generation is available for dispatch.
- From a customer's perspective, in the current market any *inefficiency* is a result of the average price resulting from a combination of the initial high price and the subsequent generator responses. In the AEMC's example, depending on the relationship of the DI 1 price to subsequent dispatch interval prices in the same settlement period, the averaging process may have benefitted customers, not disadvantaged them. This applies to both spot-exposed customers and customers whose prices are based on

[16] In New Zealand's discussions, for example, improving the Market Operator's forecasts has played an important role in discussions of how the market outcomes could be improved.

[17] AEMC, 2017, p18. We're assuming that the AEMC is not suggesting generation in the absence of a dispatch instruction, or restricting its discussion to unscheduled generation, although, on occasions in the Directions Paper the AEMC appears to be discussing flexible technologies' market participation as occurring outside dispatch, that is, as non-scheduled generation.

contract prices: the process of averaging down the price reduces the settlement price, price volatility and contract prices.

- From individual generators' perspectives, the result may be *inefficient* where the settlement price that results from "piling in" in response to the high DI 1 price is below short run marginal cost, ignoring questions of start-up and ramping costs.
  - There's an assumption embedded here about generator maximising behaviour that is arguably inconsistent with observation of the Australian electricity market. Generator bidding behaviour is described as the behaviour of unsophisticated operations, chasing transitory high prices, whereas the majority of generators and retailers operate integrated operations, bringing together spot, contract and retail markets.
  - Assumptions about generator maximising behaviour that assume that all generators are atomised entities concerned primarily with maximising their immediate spot and related contract revenues may be inaccurate when it comes to generators functioning as part of a wider portfolio. We need to consider whether integration changes generator maximising behaviour systematically and consider this before concluding observed outcomes – the "piling in" response in particular – are inefficient from participants' perspectives.
- Over the longer term, although not discussed directly in relation to this example, the AEMC argues that the result could be regarded as *inefficient* if the process of averaging down results in average prices sufficiently low that flexible generation technologies required as the market increasingly accommodates intermittent generation are uncompetitive. If this is an argument based on the technical requirements of particular types of potential new entrant technologies, then the extent to which it is consistent with the AEMC's technological neutrality needs to be discussed.

2.3. The case for increased efficiency

There are several issues here, not the least of which is the absence of any demonstrated relationship linking current high DI 1 prices to an unmet market need for flexible generation, or a persuasive argument that the frequency with which a high dispatch interval price gives rise to losses would be reduced by aligning dispatch and settlement intervals. The case still needs to be made also that achieving the efficiency improvement through alignment of dispatch and settlement is preferable to alternative responses; that is, it is less costly to implement, provides better incentives to all participants, and/or results in materially better outcomes than possible alternatives.

2.3.1. Efficiency arguments: Issues and comments

The AEMC's description of the issues raises questions regarding some of its underlying reasoning.

- First, the attribution of cause and effect to the price spikes is asymmetric.
  - Price spikes in DI 6 are artificial, illustrate the inappropriate incentives created by the 5/30 mismatch and apparently have now been addressed.
  - Price spikes in DI 1 are apparently demand led and symptomatic of an unmet but increasing market need. Generator behaviour in the subsequent dispatch intervals systematically works against efficient outcomes in the relevant settlement period by decreasing prices, discouraging the participation of flexible generation in DI 1.

  - The potential for price spikes in other dispatch intervals than DI 1 or DI 6 (or randomly at will as a result of bidding behaviour in a world where the dispatch and settlement periods are equal) is not discussed.
- Secondly, flexible generation technologies apparently play by different rules.
  - Unlike conventional generators, flexible generation technologies' participation in the market doesn't appear to affect the price achieved in DI 6: their concern is described as a function of the averaging down of the DI 6 price as a result of averaging across prior dispatch intervals in the trading period, not the likelihood of being dispatched to generate at a DI 6 price that, as the result of their competitive entry, is now lower than it would otherwise have been.
  - Given that their participation doesn't affect the price, flexible generation technologies appears to be assumed by the AEMC not be dispatched at all: repeated descriptions about their generation, as opposed to dispatch, in response to high price signals suggests that either the relevant technologies are not scheduled, in which case their unscheduled participation, although changing dispatch instructions, would not change the price; or, the relevant technologies are demand response program participants, who act to reduce demand in response to either actual or expected prices, but whose activities are not currently captured by the Market Operator in dispatch.
  - If new entrant technologies are not dispatched, over time the efficiency of the dispatch price as a signal to generators that continue to be subject to the dispatch engine will be reduced. This potential loss of efficiency needs to be acknowledged in the AEMC's argument as an offset to the claimed increase in efficiency.
- Thirdly, as described, generator bidding behaviour appears to be the behaviour of unsophisticated operations, chasing transitory high prices without having learned that competitors' behaviours in a competitive market are likely to result in all participants in the short term experiencing inefficient prices, that is, prices below short run marginal costs.
  - If generator behaviour is better described by considering observed behaviour as a response to different responses, then the description of this behaviour as inefficient may be incorrect, and changes to the Rules correcting what are assumed to be the underlying incentives may be unsuccessful.
  - Other considerations – the relationship of spot and contract prices, the performance of the portfolio as a whole considering both generation and retail obligations, and the costs of operating over the short or long term – are unmentioned. To the extent that these behaviours are prudent and rationale given generators' physical and portfolio attributes, then their omission from the analysis gives rise to a perception of inefficiency where none may, in fact, exist. Negative prices, for example, could be described as inefficient, but their role in the spot market recognises the need to recognise generators' physical dispatch requirements in the market design.

2.3.2. Competitive Bidding, Generation and Efficiency

If any of these descriptions is unsound, the AEMC's argument about the potential contribution of flexible generation technologies to the improved efficiency of the market is significantly weaker.

Competitiveness and the potential for adaptation matter: if the high price dispatch intervals observed are not demand led, then the adoption of different behaviours could undercut new entrants' prices and new entrants will fail. There will be an improvement in market efficiency, but at the cost of higher investment/lower energy market productivity.

- Our review of selected high price DI 6 intervals in the Queensland market (Appendix B) was unable to identify a related demand or supply related explanation for the events in our sample.[18]
  - The first Working Paper and the Directions Paper noted in passing the absence of material changes in demand over periods where dispatch interval prices changed significantly.[19] The results of our analysis, while based on a different sample and approach, are consistent with this. (See Appendix B and the break-out box on the following page.)
- Given the absence of clear relationships between demand or supply changes and high dispatch interval prices for DI 6 events, it's difficult to conclude that the apparent increase in high DI 1 price intervals is related to unexpected short term increases in demand or reductions in supply. If there is no persistent relationship between demand and/or supply events and DI 1 prices and their subsequent averaging down, then the competitiveness of flexible generation technologies matters.
- The AEMC's discussion of potential new entrant flexible technologies cites a range of evidence for the proposition that the price for these technologies will fall, and suggests that there's a cross-over point with gas-fired peaking generation at some point in the future, without forecasting their competitiveness.
  - If flexible generation technologies are to be dispatched, then over the longer term, the long run marginal cost of these technologies will need to be competitive with other forms of generation able to provide similar services, whatever form generation takes. Unless new entrant generators are competitive, the benefits from higher market efficiency will not eventuate.
- If, alternatively, new entrant flexible generation technologies are not dispatchable, but are unscheduled or demand response program participants, the AEMC's discussion is easier to understand.
  - The apparent assumption, however, that flexible generation technologies are outside the dispatch engine increases the difficulties confronted by the Market Operator in scheduling the market, with some cost to market efficiency, and is inconsistent with the objective of a technology neutral market and the Rule Change Proposal currently before the AEMC on participant scheduling, depending on the size of the participant.

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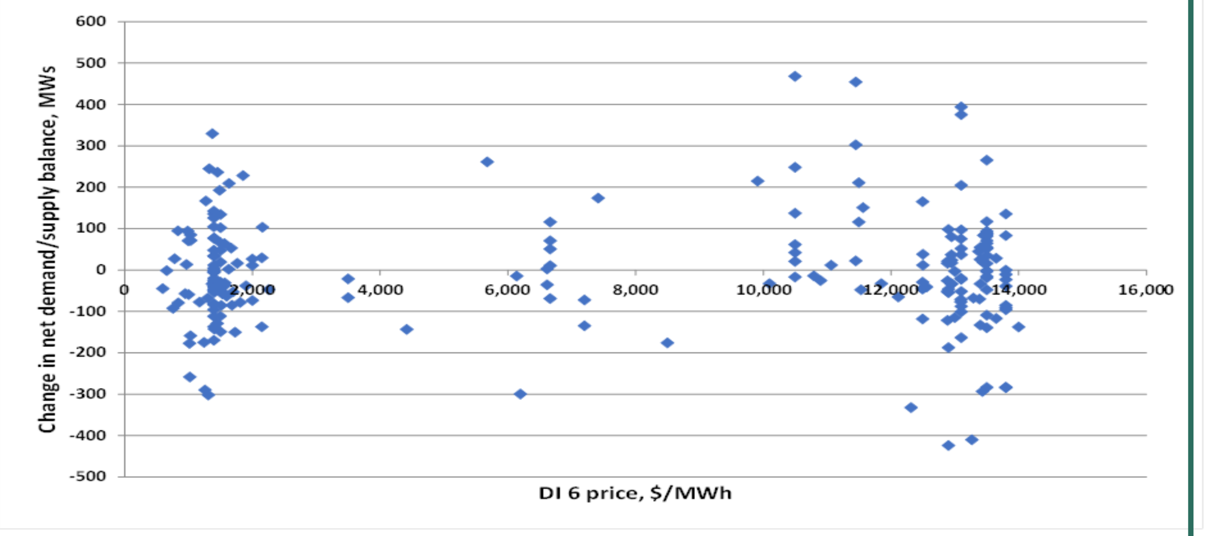
[18] Unlike the Commission's conclusions, our sample results provide only weak support for the conclusion that these events are now past as a result of the rule changes, or that DI 1 prices have now systematically increased.

[19] AEMC, 2017, pps 27 -28

Dispatch Interval 6 Price Outcomes

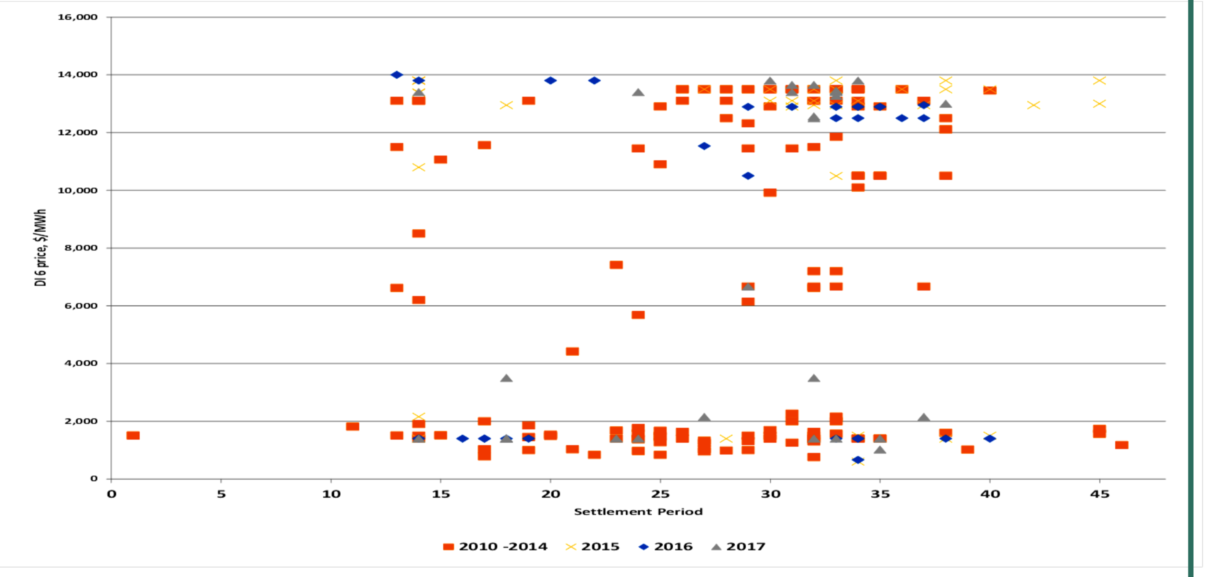
Appendix B describes our approach to selecting DI 6 price outcomes for analysis and details our results. Our sample results for Queensland demonstrate no predictable relationship between the DI 6 price and changes to the market demand or supply balance, or FCAS market outcomes in the immediately preceding dispatch interval. Figure 2.1 shows our results for the net change in the market demand/supply balance.

Figure 2.1 Events by DI 6 price outcome ($/MWh) and net change in market demand/supply balance (MWs), Queensland, January 2010 to February 2017



Our results are less supportive of the AEMC's view that there has been a material change in outcomes following recent changes to rebidding rules. As Figure 2.2 shows, there are strong continuities in the time of day at which events occur and price outcomes for the DI 6 intervals included in our sample between 2010 -2014 and subsequent years, even if in 2016 the number of events in our sample is lower than in previous years.

Figure 2.2 Events by settlement period and DI 6 price outcome ($/MWh), Queensland, 2010 – 2014, 2015, 2016 and 2017 YTD



2.3.3. Further issues

- The AEMC, in arguing that this case has been addressed by the rule changes relating to late rebidding, undermines the case for alignment (or any further action at all).
- In any event, in considering the Bidding in Good Faith Rule Change, the AEMC consistently argued that where structural issues resulted in inefficient outcomes changes to the Rules were not an appropriate response.
- Unlike Sun Metals, other large customers have argued that they will not receive the benefits identified by Sun Metals as they lack the ability to respond to changing settlement prices if the dispatch and settlement periods were to be aligned, while other wholesale market participants have queried the AEMC's views on the potential for existing generation to respond appropriately to shorter settlement intervals without significant investment.
- Further, the AEMC has identified real costs to all customers from the reduction in available hedge contracts, particularly option contracts and is vague as to whether the projected short term reduction will be addressed during the proposed transition period, or by new entrant generation in the future or at all.

The AEMC also fails to identify whether emerging flexible generation technologies will require prices to shift to higher levels overall to meet their target returns, in which case the risk of averaging down is unlikely to be the key barrier to entry; or, whether raising the cap on wholesale market prices could be a less expensive and disruptive alternative to aligning dispatch and settlement periods.

3. Measuring efficiency outcomes

3.1. Background

The Scope of Work (Appendix A) asks us to look at:

- The factors that should be considered in determining/comparing market outcomes under 5 and 30 minute settlement
- The factors that are likely to determine the efficiency outcomes under 5 minute settlement compared to the status quo
- An appropriate methodology for measuring any differences in efficiency outcomes under the status quo compared to the proposed rule change
- The inherent complexities and limitations of undertaking such an assessment
- The factors that would need to be taken into account when interpreting/utilising the output of any such analysis
- Whether international developments are useful in considering the issues raised by the Rule Change Proposal or the AEMC's proposed response.

Based on the above, the questions we have considered are: has the AEMC satisfactorily demonstrated the solution addresses the issues; and, does its solution address the likely risks? Further, in considering these questions we have reviewed:

- The Commission's proposed assessment framework, the analysis undertaken to date by the AEMC and others on key elements of that framework, and the explicit or implicit risks associated with those elements given the current state of information
- The international examples cited by the AEMC where dispatch and settlement intervals (real-time) are in the process of being aligned, to consider the purported rationale for alignment and the existence of relevant differences between those markets and the NEM with respect to market design.

Briefly, our view is that there are key questions that the AEMC, relying on its framework for assessing the proposal, should provide additional evidence and views on in assessing the proposed Rule Change because of the significant increase in potential risks to market participants that the proposed Rule Change may introduce. In some important areas the AEMC's arguments are very general and, in particular, important dimensions of time, uncertainty and risk, and the attractiveness of the investment case are not treated explicitly in their public considerations. The apparent international trend to real-time pricing provides little explicit support for the AEMC's specific arguments in favor of this Rule Change.

3.2. Measuring efficiency outcomes: Principles and approach

While as a high level principle the assumption that any misalignment between dispatch and settlement intervals is inefficient may be sound as a matter of theory, in expressing a preference in favour of alignment, the AEMC needs to identify the extent of the current inefficiency and the benefits of the proposed change. This requires the AEMC to:

- Consider what level of variation between dispatch interval prices is efficient, and what level is inefficient
- Identify the likely extent of the improvement in efficiency resulting from the alignment of dispatch and settlement
- Discuss the ways in which different classes of electricity market participants – generators, intermediaries and customers – experience the benefits of reducing the

existing inefficiency and whether, in considering different classes of participants the net benefits of reducing the inefficiency are likely to exceed the costs.

The first of these issues is addressed indirectly by the AEMC in observing that in the South Australian and Queensland markets over time the average variation by dispatch interval has widened. In Queensland the widening variation is also skewed; there is a larger increase in the size of the average DI 6 price relative to the average price for dispatch intervals 1 to 5 in the same year where the DI 6 price is higher than the price for other dispatch intervals ("overs").[20] Whether historic levels of variation are more efficient is not discussed by the AEMC: no theoretical or practical efficient level is described and, in consequence, if there was a description of the expected level of volatility in the spot market after the Rule Change, there's no yardstick by which to measure the hypothesised level of volatility.[21]

In discussing the second issue, the focus of the AEMC's discussion is the benefit to future flexible generation technologies entering the market. The source of the gain is the likely increase in the willingness of new entrants to participate, and the related increased likelihood that these entrants will be able to achieve their target or required prices for the short intervals in which they are expected to generate. As there is considerable uncertainty about what type of participants, their scale, or when and where new participants enter the market,[22] the likely extent of the efficiency can't be demonstrated by the AEMC. What our results suggest, however, is that the extent of any benefit realised is dependent on the location. Based on our sample results, history suggests the benefits are likely to be higher in Queensland and South Australia than in Victoria and New South Wales.

Finally, the distribution of benefits across electricity market participants is discussed only in relation to the disruption to hedge markets, which is assumed to be temporary, and in improving the incentives to new flexible market entrants. Our sample suggests potential benefits differ widely across the states. Costs, on the other hand, are likely to be borne by smaller customers broadly in proportion to the population in each state, and by larger customers depending on the extent to which their preferences and production technology allow a level of self-hedging, and their preferences in relation to the risks assumed in managing the cost of their electricity consumption.

[20] AEMC, 2016, p 18.

[21] This is an issue in particular in relation to the AEMC's view that there has been an observable shift towards high DI 1 prices. As we discussion in Appendix B, in the Queensland market this observation appears to be significantly influenced by a very high DI 1 price in November 2016; excluding this observation materially changes the contribution of high DI 1 prices to spot price outcomes in that year.

[22] Except to the extent that we can identify likely battery entry in the South Australian and Victorian markets as early as summer 2017/18.

3.2.1. The Commission's Assessment Framework

The Commission's assessment framework includes the following factors and measurements[23]:

- Prices that reflect the marginal cost of supply and value of its use
  - Proposed Measurement: the extent to which the proposed changes would improve price signals in the NEM, and whether this would lead to more efficient dispatch outcomes and investment decisions.
- Valuing generation and demand response flexibility
  - Proposed Measurement: whether the proposed changes would enable the market to deliver enough generating plant or demand response to meet the demand and supply balance at the time when it is physically needed by the power system.
- Technology neutrality
  - Proposed Measurement: an efficient mix of generation and consumption market responses in the short-term and an optimum mix of supply-side and demand-side investment in the longer term, minimising the costs of supply over time.
- Price risk exposure
  - Proposed Measurement: the impact of aligning dispatch and settlement on the ability of market participants to manage their price risk exposure, in particular, misalignment between the ability of participants to respond to changes in the market (via the dispatch process) with financial outcomes (settlement).
- Efficient risk allocation via contracting
  - Proposed Measurement: the potential impact of the proposed changes on the ability of market participants to efficiently allocate risk through contracting arrangements.
- Supply and demand-side competition
  - Proposed Measurement: the extent to which better incentives for demand-side participation, such as consumers deciding to curtail consumption, delay consumption, or install their own generation capacity and greater supply side competition with generators entering the market that are able to take advantage of spot price variability or existing participants investing in additional flexibility may occur.
- Regulatory and administrative burden
  - Proposed Measurement: the magnitude and distribution of the costs, involve once-off costs associated with the transition and potential on-going costs associated with the new regime that may arise if the proposed rule were to be implemented so that they can be compared against the likely benefits of making the change.

[23] AEMC, 2017, pps 9 -11

Table 3.1 is a high level summary of each of these criteria, together with the key arguments and the available evidence published by the AEMC supporting or disputing the proposition in favor of five minute settlement. At its most basic, the AEMC's argument could be described in the following terms:

- Transitory high price intervals are the source of high DI 1 prices; high price intervals will increase with the increasing penetration of intermittent renewable energy.
- There are available technologies that could, if sufficient investment were to occur, meet the demand and supply balance at the time it is physically needed by the power system, that is, during transitory high demand events. Alternatively, some combination of the current generation mix and demand side response could emerge as the efficient supplier, although investment may be required.
- These options present a significant and growing response capable of supplying (some proportion of) the reduction in cap availability that arises from the inability of existing generators to respond within a five minute interval to a price spike.
- The required investment will occur in a timeframe consistent with the proposed transition period. There will be no material disruption to the ability of risk management product markets to supply the necessary option contracts, although there will be additional complexities in providing these products.
- Customers will benefit from lower prices overall and a better alignment of consumption and prices.

The critical dependencies in this sequence are: the timely introduction of the required new investments, flexible generating technologies and new market entrants; the satisfactory ability of these participants to provide risk management products; and the extension of benefits to customers.

We understand and, to a point, accept the arguments against detailed modelling of the NEM with/out five minute settlement. The range and contestability of the assumptions that it would be necessary to make is so wide that agreement on an acceptable set of assumptions is unlikely. However, there are key areas where some form of analysis is not only feasible but desirable given the critical dependencies in the AEMC's case.

The international experience in relation to real time settlement provides examples of what could be done from an analytical perspective in providing a stronger evidence base to support the AEMC's arguments, although the international experience is less supportive than it may appear of the specific changes under review in the NEM, or the specific rationale for introducing them.

Table 3.1 Assessment Framework: Summary of the AEMC's Proposed Factors and Arguments For and against

Factor and proposed measurement	Supporting arguments and evidence	Contrary arguments and evidence
Prices that reflect the marginal cost of supply and value of its use Proposed Measurement: the extent to which the proposed changes would improve price signals in the NEM, and whether this would lead to more efficient dispatch outcomes and investment decisions	1. High DI 6 prices provide inefficient price signals to market participants managing load, resulting in over-consumption relative to the desired level of consumption. Sun Metals' original Rule Change proposal discussed this phenomenon in Queensland in relation to its own load management. 2. To the extent that high DI 6 prices are the result of underlying market conditions, price averaging across the settlement period mutes the price signal, reducing the long run responsiveness of demand side and generation participants to underlying volatility. The AEMC calculated the difference in earnings for generators under two different, hypothetical cases. 3. The AEMC argues that transitory high price intervals will increase with the increasing penetration of renewable energy. 4. What is true for DI 6 also holds for high DI 1 prices, but in the opposite direction. If market participants managing load respond to a high DI 1 price by reducing their consumption based on an expectation of ongoing high prices, they will consume less than would otherwise have been the case; while some generators will receive lower prices, having increased their generation on the assumption of persistent underlying conditions sustaining higher priced offers.	1. If high DI 6 prices are not the result of underlying market conditions, then the price spike may not be evidence of an underlying market condition that would be likely to be relied on by demand side and generation participants in considering investment decisions. 2. Our results are inconsistent with the view that high DI 6 prices result from changes to underlying market conditions. 3. The AEMC's view that high DI 1 prices result in a symmetric efficiency loss for generators and retail customers is only true if generators' behaviour is irrational. Generators, as the AEMC assumes, may "pile in" to the market in response to high DI 1 prices, and, if so, this behaviour would be inefficient relative to behaviour that, informed by better forecasting, refrained from responding to a transitory demand spike. Alternatively, generators may be knowingly defending sold option positions (settled off 30 minute prices), or acting on portfolio-wide strategies, where those portfolios include sold retail load. If generators are not piling in, but acting on some other maximising function, then although it remains true that high DI 1 prices result in some loss to market customers where the price falls in subsequent dispatch intervals, generators' strategies result only in a loss considered in isolation from other factors

Factor and proposed measurement	Supporting arguments and evidence	Contrary arguments and evidence
		governing their behaviour. 4. Our results suggest learning in generator portfolio behaviours. This observation is inconsistent with a view that 20 years into the current market, generators continue to "pile in" in response to transitory demand shocks notwithstanding the easily anticipated effect on the spot price from this behaviour.
Valuing generation and demand response flexibility <u>Proposed Measurement</u>: whether the proposed changes would enable the market to deliver enough generating plant or demand response to meet the demand and supply balance at the time when it is physically needed by the power system.	1. Sun Metals' proposal provides evidence that its demand response flexibility, up to a reduction of 100 MW consumption at any time, could provide a source of demand response at the time it's physically needed. Further, other battery/battery management companies suggest that the trajectory of market uptake of small batteries and the potential for aggregation presents a significant and growing response. 2. The AEMC's analysis suggests that the current generation mix can deliver significant quantities of short term responsiveness, although not from a resting state. Responsiveness differs by state and generator type. 3. The AEMC also argues that some retrofitting of existing generators with more responsive technologies is possible. 4. The AEMC's review of possible flexible generation technologies suggests that there are available technologies that could, if sufficient investment were to occur, meet the demand and	1. Other major users' submissions suggest that very few major users have the short term flexibility available to Sun Metals. 2. An investment case for either retrofitting existing generators or the introduction of new flexible generation technologies is required. The AEMC's evidence falls short of this. An investment case would need to consider the persistence of high transitory prices over time, as well as the price level reached. The difficulty is this: new high priced sources of generation require high achieved transitory prices to justify the investment. The AEMC is relying on the entry of these new generation sources to reduce the incidence of high transitory prices. If the investment occurs, new entrants' incentives favor sustaining high prices during transitory intervals, even if the achieved prices are somewhat lower than current intervals. Entry, therefore, is not sufficient to deliver the AEMC's benefits, while delivering the AEMC's benefits is

Factor and proposed measurement	Supporting arguments and evidence	Contrary arguments and evidence
	supply balance at the time it is physically needed by the power system. At this stage, these technologies are more expensive than existing generators and, although their cost is expected to decrease over time, the AEMC's analysis suggests that these technologies are currently uncompetitive.	unlikely to encourage entry. 3. Further, the case that needs to be made needs to consider location: the AEMC's evidence, Energy Edge's analysis and our work suggests significant differences from state to state. To the extent that other characteristics of individual markets are inconsistent with a strong investment case, the necessary investment is unlikely to occur.
Technology neutrality Proposed Measurement: an efficient mix of generation and consumption market responses in the short-term and an optimum mix of supply-side and demand-side investment in the longer term, minimising the costs of supply over time.	1. There are available technologies that could, if sufficient investment were to occur, meet the demand and supply balance at the time it is physically needed by the power system. Alternatively, some combination of the current generation mix and demand side response could emerge as the efficient supplier.	1. There is no guarantee that the short term response to the gap in the market will minimise the cost of supply over time. Effective first mover responses may discourage further market entrants by reducing or eliminating the price signal from shorter settlement periods. Further, given current market uncertainty, the willingness of market participants to undertake significant investments in the light of rapid market changes may be lower than usual.
Price risk exposure Proposed Measurement: the impact of aligning dispatch and settlement on the ability of market participants to manage their price risk exposure, in particular, misalignment between the ability of participants to respond to changes in the market (via the dispatch process) with financial outcomes (settlement).	1. Battery/battery management companies and some demand response providers suggest that the greater incentives for demand response, the trajectory of market uptake of small batteries and the potential for aggregation presents a significant and growing response capable of supplying (some proportion of) the reduction in cap availability.	1. Work undertaken by Energy Edge suggests significant losses in the ability/likely willingness of the existing generation mix to offer cap products to the market to allow market participants to manage their price risk. 2. The AEMC has not considered whether, on a state by state basis, the potential loss of hedge contracts could be offset by offers from existing generators. Nor has the AEMC considered whether and to what extent the identified short term responsiveness can be consistently

Factor and proposed measurement	Supporting arguments and evidence	Contrary arguments and evidence
		delivered across the year. Will generators be able to replace some/all of the option contracts displaced by the shift to a shorter settlement period across the year, or only in low seasons? 3. Location matters: the AEMC's evidence, Energy Edge's analysis and our work suggests significant differences from state to state. To the extent that other characteristics of individual markets are inconsistent with a strong investment case, the necessary investment is unlikely to occur.
Efficient risk allocation via contracting Proposed Measurement: the potential impact of the proposed changes on the ability of market participants to efficiently allocate risk through contracting arrangements.	1. Battery/battery management companies and some demand response providers suggest that the greater incentives for demand response, the trajectory of market uptake of small batteries and the potential for aggregation presents a significant and growing response capable of supplying (some proportion of) the reduction in cap availability.	1. Even if there is a latent but significant and growing response capable of providing (very) short term responsiveness, Energy Edge's work suggests that transitory or very short term risk management products are an inadequate substitute for the hedge contract capacity that will be lost. As a result, risk allocation opportunities will be reduced. 2. Further, as market participants suggest, the level of efficiency in allocating risk may be reduced relative to the status quo as a result of a requirement to manage multiple potential suppliers across a range of time dimensions.
Supply and demand-side competition Proposed Measurement: the extent to which better incentives for demand-side participation, such as consumers deciding to curtail consumption, delay consumption, or install their own generation capacity and	1. Battery/battery management companies and some demand response providers suggest that the greater incentives for demand response, the trajectory of market uptake of small batteries and the potential for aggregation presents a significant and growing response capable of	1. Current market arrangements for some demand side response aggregators and emerging models for battery management companies are not dispatched in competition with other supply side participants. 2. The AEMC's discussion of the role of these

Factor and proposed measurement	Supporting arguments and evidence	Contrary arguments and evidence
greater supply side competition with generators entering the market that are able to take advantage of spot price variability or existing participants investing in additional flexibility may occur.	supplying supply side competition.	participants is unclear about the extent to which flexible generation technologies can expect to be dispatched as part of the current wholesale market. 3. The balance of the anticipated effect on spot price variability and supply side competition depends on the status of these participants: included in dispatch, their presence is likely to reduce spot price variability, while scheduled outside the dispatch engine (non-scheduled load) their presence is unlikely to have the same effect on supply side competition and may reduce spot market efficiency.
Regulatory and administrative burden Proposed Measurement: the magnitude and distribution of the costs involve once-off costs associated with the transition and potential on-going costs associated with the new regime that may arise if the proposed rule were to be implemented so that they can be compared against the likely benefits of making the change	1. The AEMC believes the benefits are significant, although no quantum has been estimated.	1. Participants' estimates of the costs are significant, not including retrofitting existing generation to provide rapid responsiveness or the investment required from new market entrants. 2. Participants have not estimated the costs of withdrawing affected generation before the end of its economic life.

3.2.2. Price risk and the supply/demand balance: timing of new entrants

Energy Edge's analysis for the AEMC suggests that, in the absence of investment by existing generators to provide highly flexible rapidly responsive capacity, there will be a significant withdrawal of option (cap) contracts offered, reducing market participants' ability to manage their price risk, with a disproportionate effect on the South Australian market.[24] Investment and/or new entrants are required to fill the gap.

The AEMC suggests existing generators have capacity to respond, although not from rest and that some retrofitting could be possible. The AEMC has reviewed the potential for large scale batteries to fill the gap at some future time, and some battery/battery management companies and demand response providers suggest that the greater incentives for demand response, the trajectory of market uptake of small batteries and the potential for aggregation presents a significant and growing response capable of providing supply side competition in the short to medium term.

The gap that may emerge between the demand for and the supply of cap contracts and the potential for new technologies to fill the gap without material consequences for customer prices and retailer solvency needs to be addressed in a more granular way. Even assuming the rapid growth trajectory predicted by some potential new entrants, under the AEMC's proposed transition period, 2020-2021 is likely to be a critical year in providing substitutes for existing risk management products. Unanticipated developments in the commitment of existing generators providing these products – early withdrawal, for example – could significantly increase the risks.

Energy Edge's analysis represents a starting point from the perspective of a reduction in supply; industry participants' submissions suggest less certainty that attractive retrofitting options exist than the AEMC suggests. A range of scenarios should be developed on the time to entry and scale of new investment and new entrants, using both new entrants' claims of anticipated scale and a range of scenarios testing for the risks in the event of the failure of these plans to eventuate. In previous work on demand side management, the AEMC has developed estimates of the existing and potential capacity for demand response in the NEM. That material should be considered in evaluating the plausible scenarios for new entrants.

In considering a shift to five minute dispatch prices with 30 minute settlement (the option currently being considered for the New Zealand electricity market), a formula developed by New Zealand's Wholesale Advisory Group was adapted to estimate the costs of the transition considering new generation capacity required. The formula considers:

- the amounts of load and embedded generation that can potentially respond to short-term spot price forecasts
- the share of that capacity that does respond
- peaking generation no longer required
- the cost of new peaking generation (and the associated network expenditure)
- the discount rate
- the time until the new capacity is required.[25]

[24] Energy Edge, 2017

[25] Electricity Authority of New Zealand, *Assessment of real-time pricing options: Information Paper,* April 2016, pps 36-37

3.2.3. The investment case for retrofitting or/or new market entrants

The key arguments in favor of a shorter settlement period are the improved efficiency of the spot market resulting from improved price signals, whether considered from a load perspective or a generator's perspective, and the subsequent investment directed at providing the required responsive generation. To encourage the necessary investment, the price signal needs to be both sufficiently high and persistent. To the extent that the price signals themselves are transitory – for example, accepting the argument that high DI 6 price outcomes are now a thing of the past – the available price signals are unlikely to meet the persistence test.

Even if you assume that there are, or there will be as result of the growing penetration of renewable generation a sufficient number of appropriately high transitory price events to signal the requirement for new investment, these conditions may not be adequate. This question – whether and on what conditions the necessary investment would occur – should be pursued by the AEMC in support of its current direction.

In a similar case, the Alberta Electric System Operator (AESO) recently recommended the transition to a capacity market as a response to the Government's adoption of a hard deadline for phase out of coal fired generation and in support of the Government's climate action plans.[26] Among other grounds for its decision, the results of interviews by an investment advisory firm with generation developers, investors and lenders and consultation with expert financial advisors were used to identify if, under the current market structure, the necessary investments were likely to occur. Among other conclusions, AESO concluded that "A certain amount of revenue certainty is required to attract sufficient investor interest to deliver the generation build that Alberta will require going forward."[27]

3.2.4. In or out: benefits to market efficiency from new entrants

Are flexible generation technologies dispatched, or do they operate without directly participating in the price formation process (as non-scheduled generators, for example)? Are load responses transparent? Transparent in advance? Scheduled? The benefits to price formation, the basis for the case for shorter settlement periods, implicitly assume participation in the dispatch engine. This assumption may be inconsistent with potential new entrants' business models and conflict with other commitments or income streams such as network support.

The AEMC needs to test its implicit assumptions about new entrant participation in dispatch with potential new entrants, as well as testing new entrants' revenue targets against its view about the extent and duration of price volatility before and after new entrants' participation in the market. This can be done as a form of thought experiment: how many price spikes of what duration and how high are required to warrant (a particular form of) new entrant? How does this compare to current experience? Expected future experience?

[26] Alberta Electric System Operator , *Alberta's Wholesale Electricity Market Transition Recommendation*, October 2016

[27] AESO, 2016, p.2

Even if the frequency and size of transitory price spikes increases with further intermittent renewable generation penetration, the returns to new entrants from competing with existing generators may not meet their expectations. The difficulty is this: on the basis of current cost curves, new high priced sources of generation require high achieved transitory prices to justify the investment. The AEMC is relying on the entry of these new generation sources to reduce the incidence of high transitory prices. If the investment occurs, new entrants' incentives favor sustaining high prices during transitory intervals, even if the achieved prices are somewhat lower than current intervals. Entry is not sufficient to deliver the AEMC's benefits, while delivering the AEMC's benefits by reducing the incidence of high transitory prices is unlikely to encourage entry.

3.2.5. The benefits of real time pricing: the extension to retail customers

The extension of real-time prices to retail customers is part of the theoretical benefits of the shift towards shorter settlement periods. However, the AEMC is silent on the path to the extension of shorter dispatch interval prices to retail customers. Under existing structures for retail pricing, relatively few customers will directly experience the impact of shortening settlement to five minutes, although if the proposed changes materially affect the efficiency and availability of cap contracts, customers could be expected to see these costs indirectly in the energy component of their electricity prices. What this lag in the flow through to retail customers means for the potential for and the timeline to achieving the full theoretical benefit is unclear, but at a minimum some material delay might be anticipated either before smaller customers are affected or the full benefits are delivered.

The AEMC needs to consider the implications of this (potentially long) transition path for the achievement of the benefits. Participants' costs are incurred early in the process of changing the settlement period and investments are required upfront. Wider benefits, if realised, occur with some delay and the longer the delay the lower the contribution of these benefits, all other things being equal, to the overall benefits of the change.

3.3. International Experience

The AEMC cites studies suggesting a movement towards real time pricing in a number of electricity markets internationally. The markets cited do not support the Rule Change under consideration, whether considering the definition of efficient combinations of dispatch and settlement intervals or the rationale for the shift from the current arrangements to alignment of dispatch and settlement. The **New Zealand** electricity market is moving from the longest gap between dispatch and settlement among developed countries' electricity markets – around two days – to the current Australian alignment (five minute dispatch and 30 minute settlement) to support the development of derivative markets.[28] **FERC's** key focus is aligning the dispatch and settlement characteristics of energy, transmission and other service markets (the equivalent of FCAS markets) with the objective of, among other things, reducing the uplift (compensation) and ancillary service payments resulting from a lack of alignment across all three

[28] Electricity Authority of New Zealand, 2016

markets.[29] **Alberta** announced in 2016 its shift to capacity pricing; previous discussions of the alignment of dispatch and settlement have been overtaken by this decision.

The **New Zealand** Electricity Authority is currently investigating a real-time pricing option that would implement the five minute dispatch, 30 minute settlement process used in the NEM (Option B of several options considered). In relation to the alternative, ex post pricing based on five minute dispatch intervals, Option C, the Electricity Authority "... confirmed its decision not to pursue now the "ideal approach" of aligning the trading period with the dispatch interval and settlement prices. This is because it would require extensive changes to metering requirements, settlement and reconciliation systems, which would be in addition to the already extensive changes required to implement real-time pricing. It is likely these changes would involve substantial extra costs and time. Given the risks involved in making both sets of changes available at the same time, the Authority continues to prefer to look again at this option in the future if real-time pricing is implemented."[30]

Currently, final prices in the New Zealand market are published with a two day lag, and a variety of forecasts of final prices are relied on by participants to estimate their financial positions. The arguments in favor of a shift in New Zealand are very familiar in the Australian context – the benefits from earlier actionable prices to market participants, large and small customers, and the introduction of new technologies, but below the headlines, the specific improvements sought from the change are materially different. When the Information Paper was published, there were no traded options in the New Zealand market; real time pricing was seen to be an important element in introducing traded options contracts.[31] Since that time, the New Zealand market has moved to the introduction of traded options contracts, with a trial to commence from mid-2017. In addition, a project coupled with, and argued to provide many of the benefits of real-time pricing – improving the accuracy of pre-dispatch pricing – has commenced, but the current market development program provides no update on the progress on the decision paper on the status of real-time pricing.

FERC's 2016 Final Rule on Settlement Intervals and Shortage Pricing affects six Regional Transmission Organisations and Independent System Operators. Of those six, three use five minute dispatch *and* settlement in energy markets (California, New York, and SPP [Southwestern Power Pool]), while the remaining three combine five minute dispatch with hourly average pricing. Reviewing FERC's discussion of its decision and the deliberations that preceded the Final Rule, the improvement in the efficiency in commitments and investments, the increase in transparency, the removal of disincentives to obey dispatch instructions, and the improvement in overall reliability claimed for the Rule have their basis in the different pricing and settlement bases across energy, transmission and ancillary and other service markets for energy, shortage and ancillary services, and transmission dispatch. In some markets governed by FERC, the costs incurred in compensating generators arising from the different dispatch

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[29] FERC, 2016

[30] Electricity Authority of New Zealand, 2016, p.5

[31] Electricity Authority of New Zealand, 2016. The Electricity Authority's current website suggests options contracts will be launched from 1 July 2017, at least on a trial basis: Electricity Authority *Consultation Calendar*, March 2017.

mechanisms adopted across the different markets are apparently so large that FERC argues that their elimination would pay for the estimated costs of changing the markets to align dispatch and settlement.

It's clear from FERC's discussion that the arguments in favor of alignment relate particularly to the alignment of dispatch and settlement across the various markets operated by the RTOs and ISOs under its regulation – three of these organisations already have aligned dispatch and settlement in their energy markets, but not across intertie or ancillary markets. It's also clear from the responses of the various ISOs to FERC's Ruling that even ISOs in favor of alignment and real-time settlement see no magic in any particular time interval for alignment, particularly given member organisations' views that the costs and time required to make the change are significantly higher than estimated by FERC. The ISO/RTO Council (IRC), responding on behalf of FERC-regulated ISOs, argues for example, that it "supports the Commission's goals of aligning prices with resource dispatch instructions and operating needs. The IRC specifically supports the Commission's proposal to settle energy transactions in its real-time markets at the same time interval it dispatches energy. The IRC also believes that these principles should apply to the interties. The IRC respectfully requests that in its final order the Commission provide sufficient flexibility so that each of the ISO/RTOs can meet the Commission's directives leveraging off their existing market platforms."[32]

In the current energy only market, **Alberta** determines the dispatch price in real time for one minute dispatch intervals, and the pool price is the time weighted average of the 60 one-minute System Marginal Prices set by the System Controller.[33] However, to the extent that in the past Alberta has been discussing shortening the settlement period, this has been overtaken by the more recent decision on the change in market structure: no mention of these discussions remains on its website.[34]

When the alignment of dispatch and settlement was originally considered in the Alberta market in 2005, the benefits to the alignment of dispatch – then, as now, occurring at one minute intervals and settled on an hourly basis – were "[e]ncourag[ing] offer stability in the merit order so that it may be dispatched in a more efficient manner; [l]imit[ing] incentive for price-chasing; and [r]educing impact of price-chasing.[35] Similar to the fact situation underlying the 2016 discussions by FERC,[36] significant elements of the benefit case related to the complexity and costs of settlement where interstate and cross border transmission (intertie) settlements occurred on a different basis to the dispatch and settlement of energy, and the costs of ancillary and other services where those services were procured on a different basis to energy dispatch.[37]

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[32] Federal Energy Regulatory Commission, 2016, *Docket No. RM15-24-000: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Comments of the ISO/RTO Council",* pps 1-2

[33] Alberta Electric System Operator, *Determining the Wholesale Market Price for Electricity,* February 2011

[34] www.aeso.ca.

[35] Alberta Department of Energy, *ALBERTA'S ELECTRICITY POLICY FRAMEWORK: Competitive – Reliable – Sustainable*, June 6, 2005, p.22

[36] FERC, 2016

[37] In both cases, unlike in the NEM, there also appears to have been a significant issue in relation to compliance with dispatch orders. Both the Alberta Department of Energy and FERC identify the reduction in

Unlike the FERC Order, Alberta's approach was identified as a long-term market priority among a number of other initiatives that in the short to medium term and over the longer term were designed to improve the efficient operation of the market. Some changes to the market were introduced in 2007, including changes to the calculation of uplift prices, but although alignment of dispatch and settlement prices was identified as late as 2006 as an implementation priority for 2007,[38] it was not introduced. Between 2006 and 2015, changes in both the intention and the timing for the change occurred: the planned settlement window was only 15 minutes, although dispatch continues to occur every minute, and the priority had shifted to one of long term IT design.[39] By 2015, the market operator "noted that dispatch and settlement period alignment is not currently considered a high priority when compared to other market initiatives such as Transmission Constraints Management, Interties Restoration and Market Systems Replacement".[40]

generator non-compliance – in both directions, generating when not dispatched, and not generating when dispatched – as a material benefit to the proposed alignment of dispatch and settlement, not least because non-compliance gave rise to a significant expense in compensating generators dispatched but not required.

[38] Alberta Electric System Operator, *Transmission and Market Development in Alberta, Presentation by M. Dale McMaster President & CEO of AESO to IEEE 2006 PES General Meeting*, Montreal, June 20, 2006

[39] Alberta Electric System Operator, (2015)

[40] AESO, 2015, p.2

4. Assessing the merits of the Rule Change proposal: benefits vs. costs

4.1. Background

The Scope of Work asks us to look at:

- The merits of the AEMC's proposed assessment framework
- The utility of a cost benefit analysis in any decision making framework used to assess the merits of the proposed rule change and any limitations to such analysis
- The key underlying assumptions that are likely to determine the magnitude of any ongoing costs and benefits if 5 minute settlement is introduced
- The likely timing of any such costs and benefits
- Key scenarios and sensitivities worth exploring when considering any ongoing costs and benefits that are likely to eventuate if the rule change is implemented.

Section 3.2 discusses the AEMC's proposed assessment framework, the issues of timing in realising the benefits from the proposed Rule Change, and key scenarios and sensitivities. As we noted in Section 3, up to a point we accept the arguments against detailed modelling of the NEM with/out five minute settlement: the range and contestability of the assumptions that it would be necessary to make is so wide that agreement on an acceptable set of assumptions is unlikely. However, in Section 3 we have identified a number of analyses the AEMC should undertake to provide additional support to its current position that it favors making a more preferable rule broadly consistent with Sun Metals' proposal.

The additional questions we have addressed in considering these issues are the risks to achieving the benefits in addition to those raised in Sections 3.2.3 to 3.2.5, and how these risks could be captured by the AEMC's assessment of the Rule Change proposal.

4.2. Are the benefits achievable?

We have been asked to identify the key underlying assumptions that are likely to determine the magnitude of any ongoing costs and benefits if five minute settlement is introduced. In this section we've left aside the issues raised in Section 3 relating to the likelihood and timing of the necessary investments to address wider questions relating to the proposition that shorter settlement periods provide more efficient price signals to generators and customers, and benefits to customers and the economy.

4.2.1. Will prices be less volatile?

That prices will be less volatile is presumed, not demonstrated. The AEMC has effectively offered two arguments: late volatility in a settlement period is a function of the inefficient incentives offered by averaging; while volatility early in a settlement period is met by a late, inefficient response to a transitory change in demand and/or supply. If volatility results from transitory influences on demand and/or supply, the AEMC's intention of reducing the barriers to entry for highly flexible generation technologies is appropriate, although the AEMC has not made the case that the proposed Rule Change is either necessary or sufficient to achieve the desired result.

If volatility results from the incentives presented by averaging the AEMC's argument may also be correct, although the AEMC fails to consider what the level of volatility might be in circumstances where there is no averaging, and no ability for market participants to modify a price spike once it occurs. Participants' outcomes may not be improved, even when averaging is removed.

How can the proposition be tested? We need more sophisticated mental (and dispatch) models of portfolio behaviour that recognise the different incentives generators may face depending on their status as atomized merchant plants, members of long/short portfolios (in the Australian context, gentailers), members of long only portfolios and other possible portfolio characteristics. And we need to better consider state-by-state outcomes in the context of generator portfolio characteristics and other characteristics of the individual state markets. These models might provide more insight into the potential outcomes of proposals such as Sun Metals' Rule Change Proposal.

There are other, more difficult questions that need to be considered, for which modelling is unlikely to provide an answer.

- What is the expected level of volatility from dispatch interval to dispatch interval, and what represents an artificial level of volatility?
- How do we separate that level of volatility necessary to sustain the new entrant technologies as profitable market participants from unnecessary or "artificial" volatility?
- How much less volatility is likely to satisfy spot-exposed customers' criticisms of current market outcomes, and is this likely to be achievable?

4.2.2. What is the cost of lower volatility?

Finally, there's no discussion in the Directions Paper of the implications for energy productivity and dynamic efficiency – implementing the Rule Change requires higher investment and consequently, additional costs, but, assuming the observed dispatch interval volatility is the outworking of more frequent transitory effects on demand or supply, the resulting extra services are unlikely to be observed by customers, even though they will bear the costs along with existing market participants.

Over the longer term, the AEMC relies on the phase-out of existing generators. The implicit argument is as follows: since at some point in the future all current generators will retire, the cost of requiring different response times consistent with a shorter settlement period is irrelevant. New generators will have the necessary level of responsiveness. In the short to medium term, however, there is a cost: higher investment is required to deliver customers the expected level of energy service.

In Section 3.2 we've discussed the need to quantify (notwithstanding the difficulties of the exercise) the required new generation and the timelines for its installation should it be committed. That exercise could be the basis for estimating the likely short to medium term impacts on energy productivity from the transition to more flexible generation technologies. If the transition is required, and we have confidence in the direction, then the associated costs, and the implications for customers' prices, should be acknowledged and explained.

4.2.3. How are the costs collected and the benefits distributed?

We think the behaviour the basis for the Rule Change Proposal has historically been concentrated in the Queensland and South Australian markets. To the extent that there are benefits they will be larger in these markets than in Victoria and New South Wales. The nature of the typical cost recovery mechanisms, however, will smear the costs across the NEM in proportion to the number of customers in each state and then depending on the extent of competition in each market to customers and shareholders of affected market participants.

In Section 3.2.5, we noted that the extension of the benefits of the change to smaller retail customers relied on, among other factors, the willingness of relevant regulatory authorities to allow (and customers to take up) tariff structures that reward flexible customer behaviour.[41]

The AEMC should acknowledge the likely difference of customers' net outcomes in the short term; some quantification by customer class could be attempted, as has been the case with other Rule Change proposals. Acknowledging that customers' experiences will differ is not inconsistent with proceeding with the Rule Change; it would be a reasonable and realistic basis for considering its merits.

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[41] This issue raises the further questions about the effects on competition and retailer solvency if, caught between pricing structures inconsistent with the new shape of the options market and spot market behaviour that presents difficult to manage risks, retailers are unable to either pass through their risks or appropriately manage them.

A. Five Minute Settlement Rule Change Proposal – Request for Proposal

Background

The Australian Energy Market Commission (AEMC) is currently considering a rule change proposal from Sun Metals (the proponent) that seeks to align dispatch and settlement intervals in the National Electricity Market (NEM).

The proponent's rationale for the rule change is that the current market design accentuates strategic late rebidding and impedes market entry for fast response generation and demand side response.

The AEMC has undertaken some high-level analysis to consider the nature of the issue and extent to which 30 minute settlement may be distorting efficient market outcomes in the NEM relative to 5 minute settlement. A summary of the AEMC's preliminary views is provided below.[42]

- The proponent's proposal is seeking to increase the efficiency of spot market prices and the signals they provide with regard to the value of generating and consuming electricity at different points in time.
- Economic theory supports aligned intervals for dispatch and settlement, with 5-minute settlement delivering more efficient market outcomes. This has been acknowledged by a range of international energy market authorities and in the few overseas markets where dispatch and settlement are not aligned (i.e. some US markets, New Zealand and Alberta), regulators and market bodies are either in the process of aligning or recognise the merit in doing so.
- Implementing the proposed change could impose significant costs, but it is important to distinguish between transitional and ongoing costs. Transitional costs, while potentially large, are solely related to switching from the existing arrangements to the new ones, while ongoing costs are additional and will persist beyond the initial implementation.
- In light of the above, the key issue is one of materiality (i.e. how significant are the differences between 5 and 30 minute prices and how might behaviour change if they were to be aligned).

Despite the AEMC's initial view, the economic rationale for aligning dispatch and settlement intervals in the NEM and extent to which it will deliver efficiency gains is yet to be robustly explored. Regardless of the theoretical rationale, this analysis is necessary to understand the materiality of any existing market inefficiency and scope for improvement.

Consideration must also be given to how best to measure the potential ongoing costs and benefits of 5 minute settlement. The limitations of quantitative modelling are recognised in this respect. But it is important to identify and understand the factors that will influence the level of any potential benefits, as well as the extent to which they may also impose additional on-going costs relative to existing arrangements.

[42] As outlined in the attached Working paper's prepared by the AEMC.

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Scope of work

Origin is seeking to engage a qualified consultant to examine and report on aspects of the proponent's proposal and preliminary views expressed by the AEMC. Origin expects the advice provided will be largely qualitative in nature and underpinned by relevant data (where necessary) rather than detailed quantitative modelling.

The report should address the following.

1. Determining market outcomes under 5 minute settlement

- To what extent is the underlying assumption (that alignment of dispatch and settlement intervals at 5 minutes will lead to more efficient market outcomes), reasonable in the context of the NEM?
- What factors should be considered in determining/comparing market outcomes under 5 and 30 minute settlement? These could include:
  - Efficiency measures – i.e. productive; allocative; and dynamic
  - Volatility (both frequency and magnitude) - while volatility is an inherent feature of an energy only market, its existence also has implications for risk management. Inclusion of safety nets such as the market price cap and cumulative price threshold indicate that the policy intent is that there should be limitations on volatility.

2. Measuring efficiency outcomes

- Discuss the factors that are likely to determine the efficiency outcomes under 5 minute settlement compared to the status quo. These could include:
  - Assumptions regarding generator behaviour;
  - Uptake of new technologies such as fast response plant;
  - Capability/responsiveness of load; and
  - Capability/responsiveness of existing plant
- What is an appropriate methodology for measuring any differences in efficiency outcomes under the status quo compared to the proposed rule change?
- What are the inherent complexities and limitations of undertaking such an assessment?
- What factors would need to be taken into account when interpreting/utilising the output of any such analysis?

3. International experience

- Of the international examples cited by the AEMC where dispatch and settlement intervals (real-time) are in the process of being aligned:
  - What is the purported rationale for alignment? Consideration should be given to the level of disparity between dispatch and settlement intervals, the underlying issues driving alignment, and materiality of any market inefficiencies identified (where already quantified/qualified).
  - Are there relevant differences between those markets and the NEM with respect to market design (e.g. capacity markets, gate closure)?

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4. Assessing the merits of the rule change – Cost vs. Benefits

- Discuss the merits of the AEMC's proposed assessment framework
- How useful is a cost benefit analysis in any decision making framework used to assess the merits of the proposed rule change? Are there any limitations to such analysis?
- What are the key underlying assumptions that are likely to determine the magnitude of any ongoing costs and benefits if 5 minute settlement is introduced?
- What is the likely timing of any such costs and benefits?
- What key scenarios and sensitivities are worth exploring when considering any ongoing costs and benefits that are likely to eventuate if the rule change is implemented?

Deliverables

The consultant is required to provide a Draft Report prior to project completion.

Project Timeframe

The consultancy will commence in January 2017 and is expected to be completed in February/March (final date to be determined).

B. Analysing Dispatch Interval Six: Our approach

In this report, we include selected results from our analysis of Dispatch Interval Six (DI 6) outcomes for the New South Wales, Queensland, South Australian and Victorian electricity markets for the period from 1 January 2010 to 21 February 2017. The results presented focus on a sub-set of all DI 6 outcomes (events) where the price is higher than the average of the preceding dispatch intervals, DI 1 to DI 5, in the same settlement period, including only:

- DI 6 intervals where the DI 6 price is three times or more higher than the average price for the prior dispatch intervals in the same settlement period, DI 1 to DI 5; and
- Where the DI 6 price was higher than $500/MWh.

In defining the criteria for a sub-set of the total possible periods where the DI 6 price was higher than the average of the previous dispatch interval prices in the same settlement period, we intended to focus on events where the driver(s) of the DI 6 price could potentially be identified by excluding small changes in the DI 6 price relative to the average of the prior dispatch intervals. The size of our sample is an outcome of the criteria chosen; different criteria would give rise to different size samples.

The AEMC compares the average of all DI 6 prices to all other dispatch interval prices, but this comparison overlooks the potential relationships from one dispatch interval price to another, as influences on demand (time of day, day of the week, weather) and supply (available generation) are likely to be reasonably stable over a number of dispatch intervals. By viewing price outcomes independently from each other, it also may conceal relationships from, for example DI 6 to the following DI 1: dispatch interval prices may display a longer continuity when considered in this way. Our analysis focusses on discontinuities in DI 6 prices.

As a result of the criteria used:

- the total number of events included in our analysis is reduced to 353 over the period chosen.[43]
  - There are slightly more than 210,000 DI 6 intervals over the period of our analysis where the DI 6 price is higher than the average of the preceding dispatch intervals in the same settlement period, ***and*** the DI 6 price is higher than -$1,000/MWh.
  - Our sample represents 0.2 percent of all occasions over the selected time frame when the DI 6 price was higher than the immediately preceding dispatch intervals in the same settlement period.
- the distribution of events by market is changed materially.
  - Looking at the 211,328 occasions where DI 6 was higher than the average of the immediately preceding DI 1 to DI 5 price ***and*** the price in the relevant DI 6 interval was higher than -$1,000, over the period from 1 January 2010 to 21 February

[43] There are 353 events in our sample, including 5 events where the average of the price for the dispatch intervals immediately preceding the high priced DI 6 interval is negative, and 348 intervals if negative prices are excluded. Excluding negative prices excludes two events each in New South Wales and Victoria and one in South Australia.

  2017, the events are spread evenly across the New South Wales (24.8 percent of all occasions), Queensland (25.4 percent), South Australian (25.2 percent) and Victorian markets (24.6 percent). Tasmania was not included in our analysis.[44]
  - However, in our sample, events in the Queensland market account for 63 percent (222) of the 353 intervals included. There are also 83 events in the South Australian market over the same period, 27 in Victoria and 21 in New South Wales. Given the disproportionate representation of events in Queensland in our analysis, much of subsequent analysis in this paper focusses on this market.
  - Higher average prices in the Queensland and South Australian markets may explain the greater representation of these two markets in our sample. Considered together, events in Queensland and South Australia account for 86 percent of all events in our sample.

In undertaking the analysis, we were aware of the analysis published by the AEMC's Working Group, which suggested that it was difficult to find seasonal or other explanations for the DI 6 outcomes examined. Our results, discussed below, suggest some seasonal and time of day effects for the events considered. Our more significant finding is the absence of identifiable relationships between demand or supply changes, either individually or collectively, between high priced DI 6 and immediately preceding dispatch intervals in the Queensland market (see following).

Events by jurisdiction and other characteristics

By jurisdiction, settlement period and month

Figures B.1 to B.3 show the total number of defined events by settlement period for Queensland, South Australia, New South Wales and Victoria. The results show the difference between Queensland and other jurisdictions:

- the frequency of events is significantly higher in Queensland than in other jurisdictions
- the frequency distribution of events in Queensland shows a strongly bi-modal pattern, with a significant clustering of events in settlement periods 15 to 17 (62 events) and 20 events occurring in settlement period 35.
  - This cluster may be associated with the peak to off-peak hot water switching time profile used in Energex's demand side management program, but we have been unable to test this hypothesis directly. Our results looking at underlying physical market characteristics that might explain the events also provide no support for this possible explanation.
- To the extent that we can conclude from the small number of events in our sample, the frequency distributions of events in New South Wales and Victoria, and to a lesser extent South Australia show events most likely to occur in the late afternoon or early evening, when demand is at its peak in summer months. There is some suggestion of a bi-modal distribution similar to Queensland's, but much less prominent in the results for these markets, because significantly less frequent.

[44] Roughly calculated, in each jurisdiction DI 6 intervals where the price was higher than the average of the previous dispatch intervals in the same settlement period represent about 8 percent of all intervals over the period of our analysis. If dispatch interval prices were random, then you might anticipate this to be a higher proportion of all intervals: as only one interval in each dispatch period can be the highest, you might expect the number of occasions when DI 6 was the highest price to be closer to around 17 percent of all intervals.

Figure B.1 Queensland: events by settlement period, Jan 2010 - Feb 2017, number of events

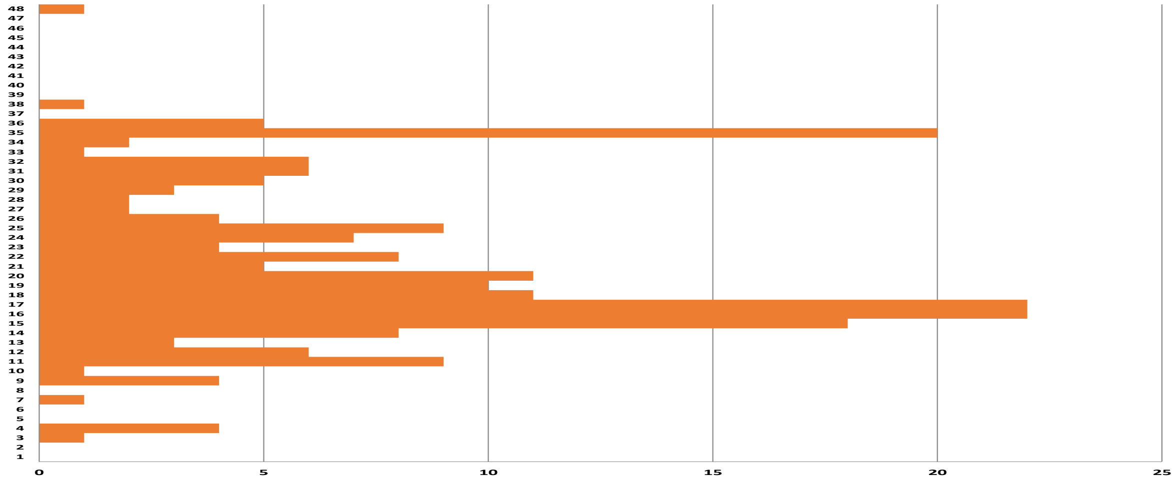

Figure B.2 South Australia: events by settlement period, Jan 2010 - Feb 2017, number of events

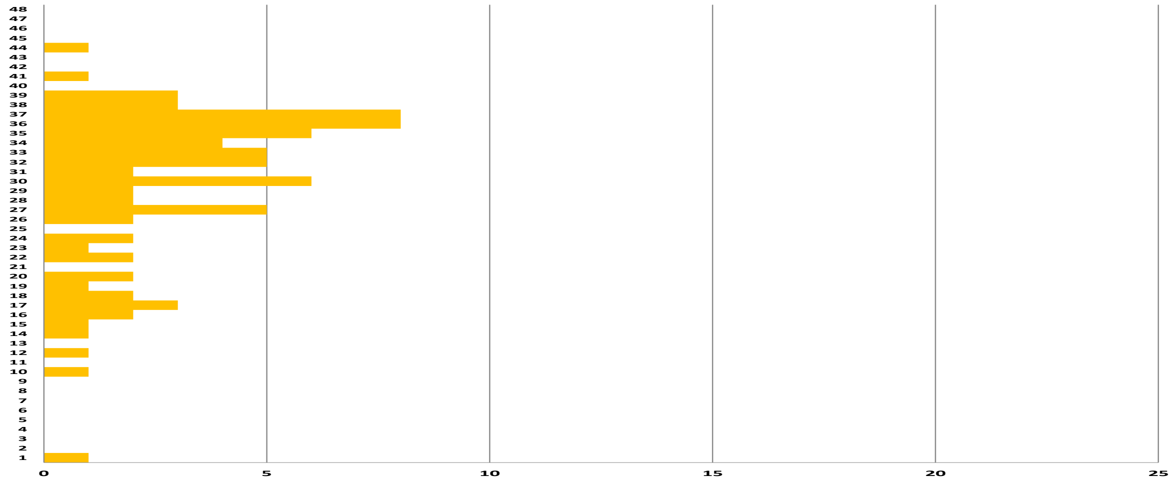

Figure B.3 New South Wales and Victoria: events by settlement period, Jan 2010 - Feb 2017, number of events

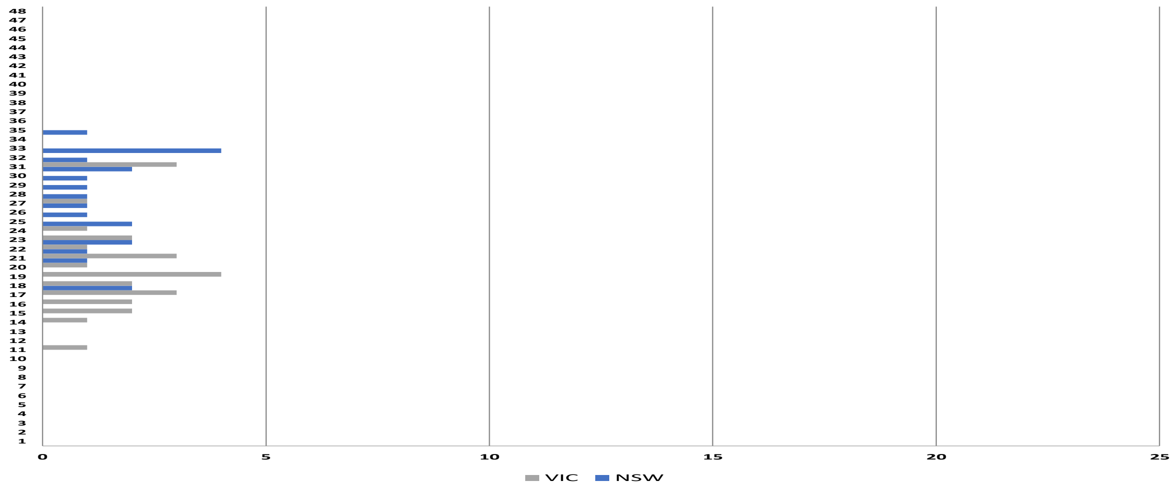

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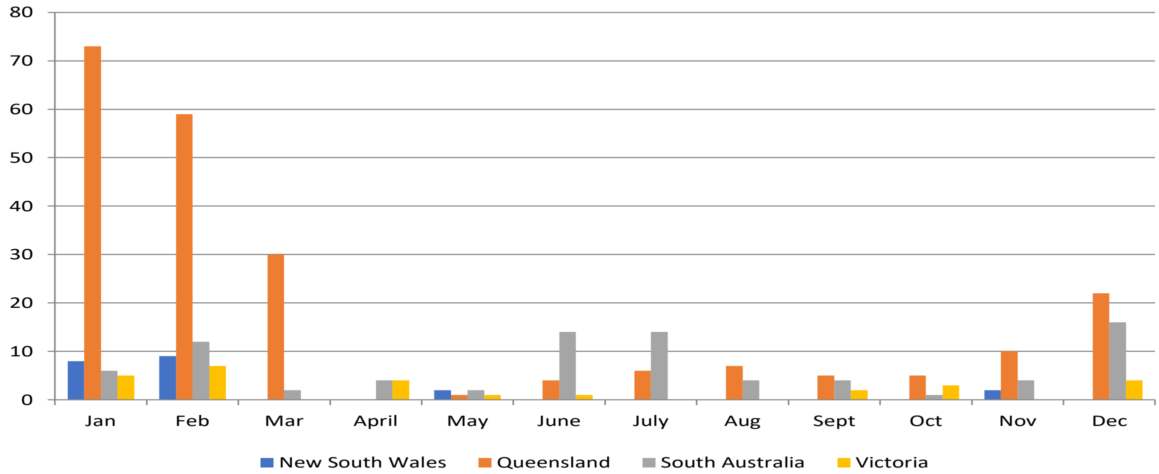
Figure B.4 Events by state and month, Jan 2010 to Feb 2017, number of events



Looking at events by time of year suggests some association between the number of events in our sample and summer. Figure B.4 suggests that, with the exception of South Australia, the summer months have a disproportionate share of all events. This is particularly the case for Queensland, where slightly less than three quarters of all events occur in the first three months of the year, but is also the case in New South Wales and Victoria.

The number of events in June and July is disproportionately high in South Australia.

The data underlying our analysis ends in mid-February 2017, when we began our analysis. Given the previous concentration of events in the summer period, the results for 2017 (see below) may under- or overestimate the extent to which recent changes to the NER have changed market outcomes.

Queensland results: events and underlying market changes

Our analysis has focussed on events in the Queensland market and changes in underlying market conditions in the Queensland market. Queensland accounted for 63 percent of all events in our sample, more than expected. Our original intention had been to do a pairwise comparison of Queensland's results with those of either Victoria or NSW; differences between industry structure and performance of the South Australian market and other Australian electricity market mean that results from the South Australian market may not be generalizable to other markets. The dominance of events in Queensland in our sample, however, made pairwise comparisons difficult: at 21 and 27 events in the NSW and Victorian markets respectively, it would be difficult to draw many inferences from the results of any comparison.

The dominance of events in Queensland in our sample raises a different, but important question: what are the characteristics of the Queensland market which give rise to the outcome in our sample? To the extent that the current mismatch between dispatch intervals and settlement periods presents an incentive to generators to bid or rebid into DI 6 so as to increase the average price for all dispatch during the relevant settlement period, then regardless of location generators face the same incentive. Our starting point, therefore, was a view that physical characteristics of the Queensland market, including

Figure B.5 Events by DI 6 price outcome ($/MWh) and change in demand (MWs), Queensland, January 2010 to February 2017

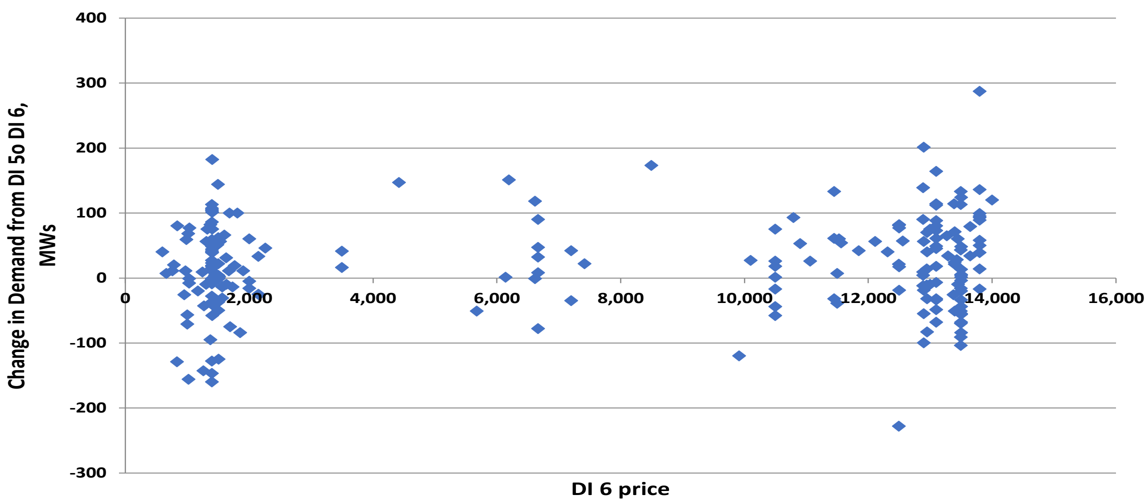


Figure B.6 Events by DI 6 price outcome ($/MWh) and change in supply (MWs), Queensland, January 2010 to February 2017

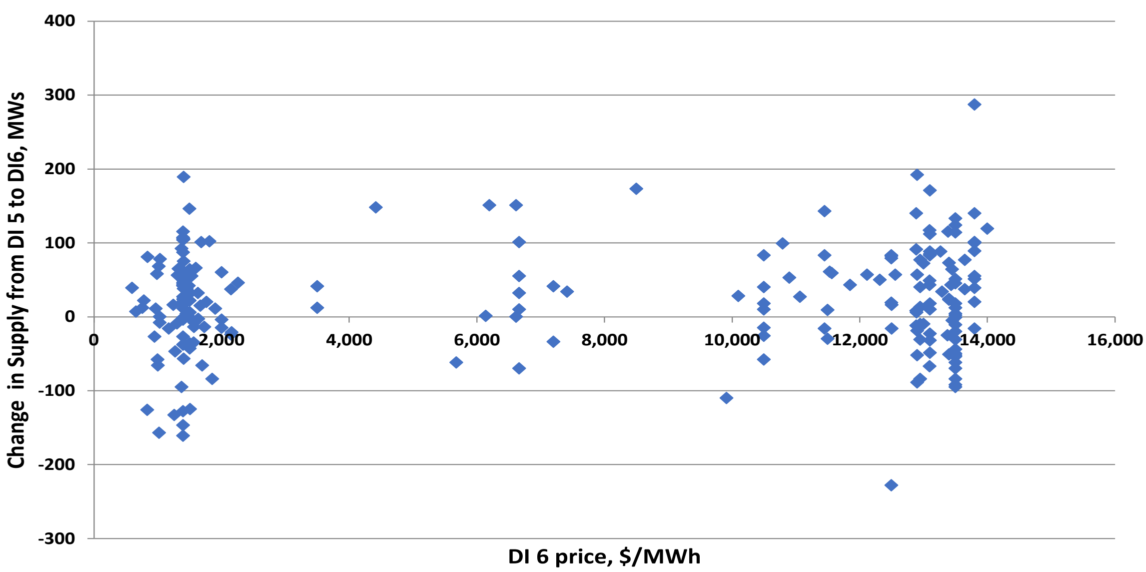


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Figure B.7 Events by DI 6 price outcome ($/MWh) and change in exports (MW), Queensland, January 2010 to February 2017

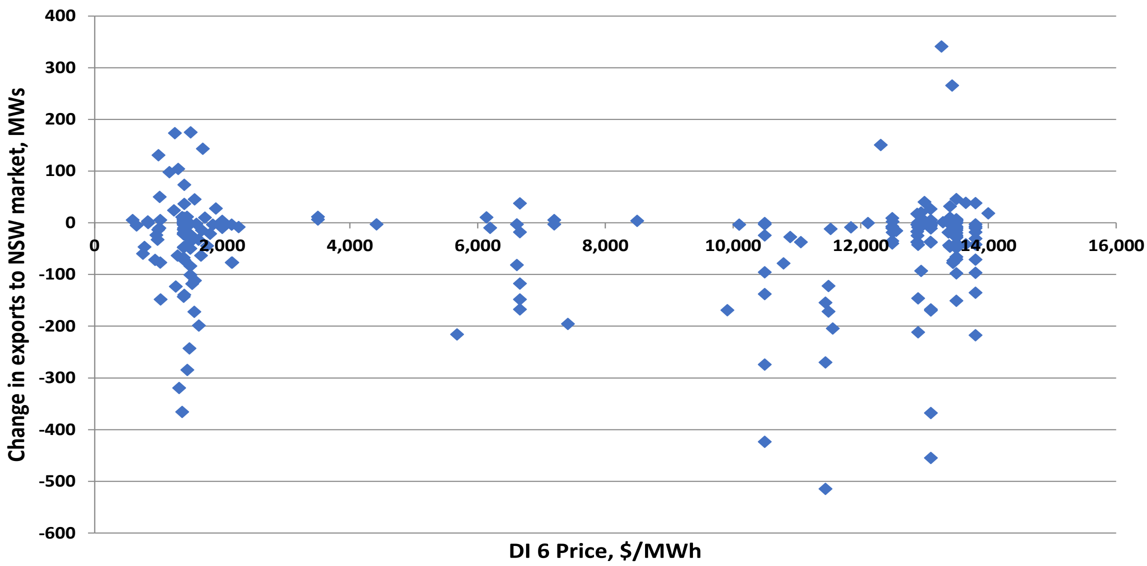
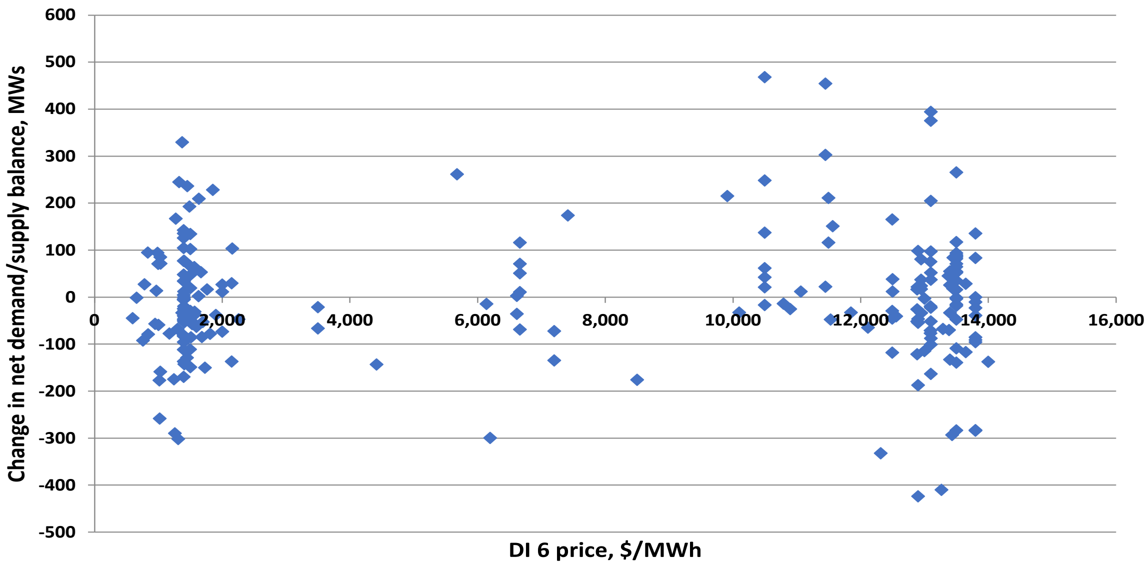


Figure B.8 Events by DI 6 price outcome ($/MWh) and net change in market demand/supply balance (MWs), Queensland, January 2010 to February 2017



the interaction of distribution load management programs, might explain our findings. To identify potential relationships between our results and the underlying market characteristics, we looked at the relationship between events and, both separately and together:

- the change in demand from DI 5 to DI 6, measured in MW (Figure B.5)
- the change in available generation from DI 5 to DI 6 measured in MW
- the difference in dispatched generation between DI 5 and DI 6 (Figure B.6)
- the difference in contributions to the NSW market from the Queensland market between DI 5 and DI 6 (Figure B.7).

Briefly, we found no relationship between these factors separately or in combination with the events in our sample. The scatter charts (previous page and opposite) plot our results for demand, supply, exports and net market demand/supply change (change in availability *less* the change in exports *less* the change in demand, Figure B.8) for each of the events in our Queensland sample.[45] The results graphically demonstrate the absence of any clear relationship. However, they illustrate the typical bidding price structure in the Queensland market, with bids falling into a small number of well-defined price bands.

We also looked for any relationship between FCAS market activity, considered either as a change in volume, up or down, or a change in price, up or down across a range of FCAS markets. The results, not shown, are similar to the results for changes in demand and/or supply; our results show no observable relationships.

While the DI 6 intervals in our analysis have prices that are absolutely high, considering electricity market price outcomes, and at least three times higher than the average of the immediately preceding dispatch intervals in the same settlement period, we have not been able to demonstrate that these price outcomes are associated with changes to the underlying market demand/supply balance in the Queensland market. The absence of any apparent relationship between underlying physical market conditions that we've investigated, or relationship with FCAS markets suggests to us that there's no easily observable relationship between underlying market conditions and the events in our Queensland sample. In turn, this raises a number of significant questions.

- If changes in the underlying physical market – demand or supply – don't explain the change in the dispatch interval price relative to the average price of the related dispatch prices, what does? This question is important because, to the extent that the benefits of five minute settlement rely either explicitly or implicitly on an underlying physical market requirement to be met, not being able to identify that physical market requirement weakens that case.
  - We have not repeated our analysis of the relationship between DI 1 prices and demand and/or supply impacts, which the AEMC argues represents a recent shift in market behaviour and a source of additional inefficiency relative to the original basis for the Rule Change Proposal. However, our view is that our findings would be likely to be similar to the results for DI 6 prices; no obvious relationship will be observable.

[45] Conventionally, scatter plots would show the x and y axes in these charts reversed. It's a weakness of Excel that the number of events can't be accommodated in the conventional format in these charts.

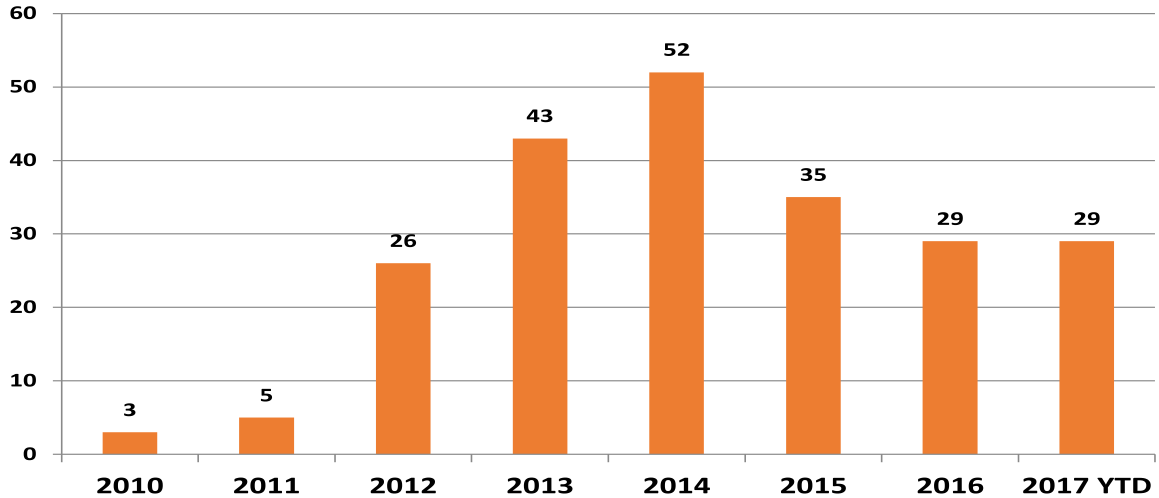
  - In the Queensland market, it's not clear that high DI 1 prices are now more prominent in Queensland than high DI 6 prices; the AEMC's argument in relation to DI 1 prices is only correct if outcomes in November 2016 are included. In November 2016 the maximum DI 1 price in Queensland was just under $13,000/MWh and no other dispatch interval price in that month was higher than $1,400/MWh, Excluding that month materially changes the rank order for dispatch interval outcomes in Queensland in 2016. Further, looking at the same data for previous years in Queensland shows 1 or 2 results a year where the maximum price in an interval other than DI 6 was very high relative to all other prices in the same month. In those results, DI 2 and DI 5 contain the most frequent outliers, three occurrences in both cases out of a total of eight across the entire period.

- What would an alternative explanation mean for the potential for a rapid response service, however defined, to profitably provide services to the wholesale market?
  - If, for example, the existence of high DI 6 prices or, assuming the AEMC is correct, high DI 1 prices, is a function of industry structure, any rapid response service may find that, in the absence of underlying physical market opportunities, opportunities to profitably generate may be scarce.

Consistency with earlier findings: Late Rebidding Rule Change

Figure B.9 shows the number of events by year in Queensland over the period of our analysis. In 2012, following the Queensland Government's decision to reduce from three to two its generation portfolios, there was a substantial increase in the number of events, from 5 in 2011 to 52 in 2014. The number of events in our sample then declines by around 40 percent from the peak in 2014. The decline observed in 2015 relative to 2014 could possibly be attributed to the effects of the Bidding in Good Faith Rule Change Proposal, although that proposal was only lodged in April 2015. Further, our results suggest the decline may not be strong or persistent, given the 2017 results for the period to mid-February 2017.

Figure B.9 Events in Queensland, by year, 2010 – February 2017, number of events



Our results show a slightly different pattern to the AEMC's for the Queensland market: our sample shows a significant increase in events in 2012 relative to the previous year, and a reduction in 2015 and 2016 relative to 2014.

While the frequency of events in our sample may have declined since the 2014 peak, those events which have occurred in Queensland following the introduction of the recent changes to rebidding requirements have strong commonalities with earlier events. Figure B.10 shows events by settlement period for Queensland for 2010 to 2014, 2015, 2016 and 2017.[46] Events in 2015, 2016 and 2017 ytd may be slightly fewer than in previous years (Figure B.9), but the time of day and the pricing displayed are very similar to previous years, as is the relationship, or lack of one, between net demand and high priced events (Figure B.10 and Figure B.11).

[46] The changes to the Rules were introduced with effect from 1 July 2016. There was only one event in 2016 after this period; dividing 2016 into a before/after buckets provides very little additional explanatory value.

Figure B.10 Events by settlement period and DI 6 price outcome ($/MWh), Queensland, 2010 – 2014, 2015, 2016 and 2017 YTD

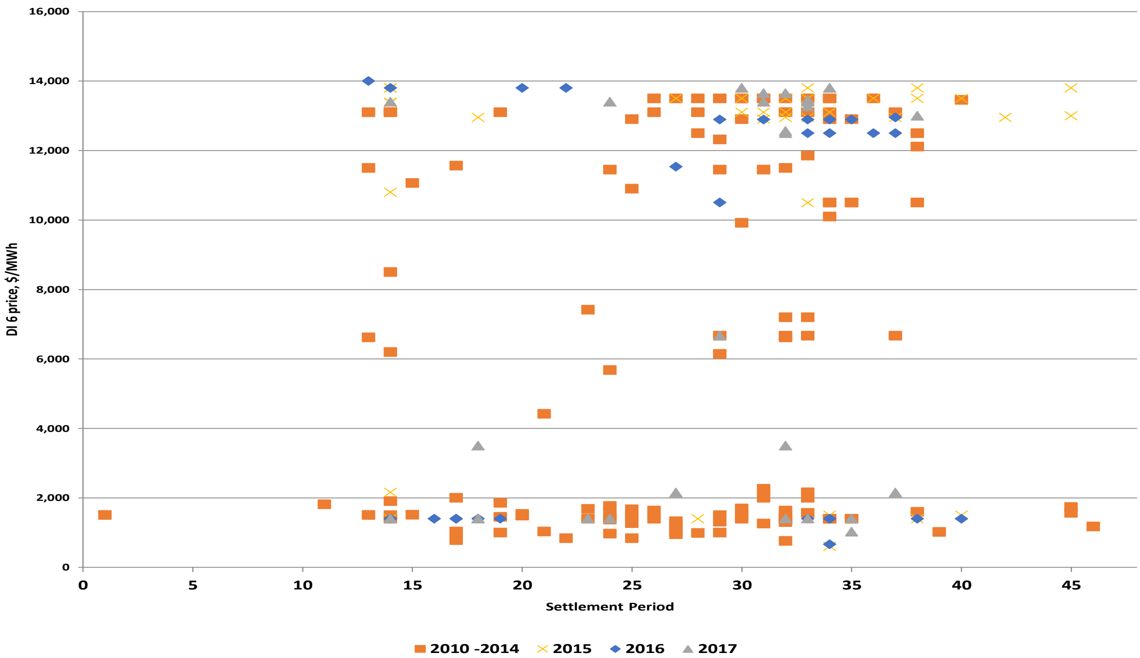
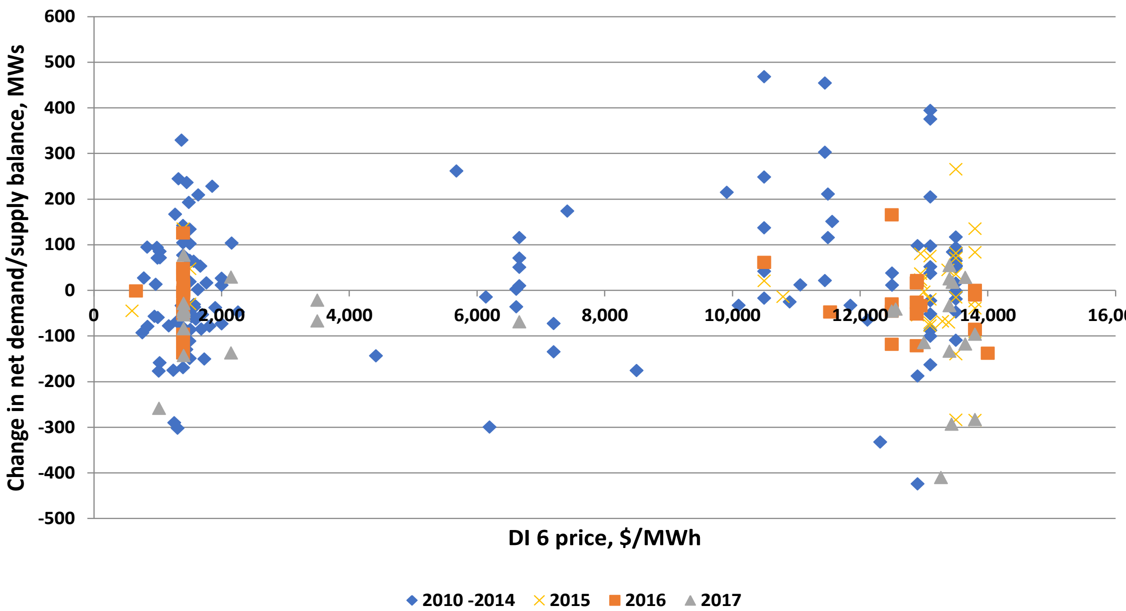


Figure B.11 Events by DI 6 price outcome ($/MWh) and net change in market demand/supply balance (MWs), Queensland, 2010 – 2014, 2015, 2016, 2017 YTD



Tentative conclusions

High priced DI 6 intervals in Queensland dominate our sample for New South Wales, Queensland, South Australia and Victoria. Although high average Queensland prices may explain part of this outcome, the number of events in the Queensland market included in our results is more than twice the number of events in the South Australian market, and more than 10 times the number of events for the same period in the Victorian or NSW markets.

We haven't been able to identify changes in demand or supply immediately prior to the high price DI 6 events in Queensland in our sample. Similarly, we have been unable to demonstrate any relationship with a range of FCAS market changes, either in prices or volumes. We do see industry structure and portfolio effects in our results.

Looking at the questions our analysis has raised, then:

- We have not identified relationships between demand or supply changes, either individually or collectively, between high priced DI 6 and immediately preceding dispatch intervals in the Queensland market.
  - The DI 6 intervals in our analysis have prices that are absolutely high, considering electricity market price outcomes, and at least three times higher than the average of the immediately preceding dispatch intervals in the same settlement period. Given these characteristics, we anticipated that some relationship between demand and/or supply could be demonstrated, but we have not been able to demonstrate that the price outcomes for the DI 6 intervals included in our analysis are associated with changes to the underlying market demand/supply balance in the Queensland market.
  - This finding is important because, to the extent that either explicitly or implicitly the case for five minute settlement relies on an underlying physical market requirement, not being able to identify the physical market requirement weakens that case.
  - If, for example, the existence of high DI 6 prices is a function of industry structure, any rapid response service may find that, in the absence of underlying physical market opportunities, opportunities to profitably generate will depend on the rapid response service's position in the merit order. If more expensive than existing generators, the new entrant can be undercut by existing generators on any occasion where the new entrant is not the marginal generator.

While we can't explain what gives rise to the change in the DI 6 price relative to the average price of the preceding dispatch prices in the same settlement period, the outcomes in our sample, whether considered in relation to the time of day (Figure B.10) or the combined change in the demand/supply balance (Figure B.11) look to be very similar across the period of our analysis. But, If this relationship is a characteristic of the structure of the Queensland market, then, as was the case in relation to the Bidding in Good Faith Rule Change proposal, the questions that need to be considered are, first, whether changes to the Rules are appropriate to address industry structure and, secondly, whether the costs to all market participants are appropriate to address an issue that appears, on the basis of our findings, to be specific to the Queensland market.

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