RULE

Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (MARKET MAKING ARRANGEMENTS IN THE NEM) RULE 2019

PROPONENT

ENGIE

19 SEPTEMBER 2019

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has decided not to make a final rule in relation to a rule change request from ENGIE to require the Australian Energy Regulator (AER) to operate a tender for the provision of market making services in the National Electricity Market (NEM).

2 The ASX market making scheme commenced on 1 July 2019. The Retailer Reliability Obligation (RRO) and the associated Market Liquidity Obligation (MLO) have also been in operation since 1 July 2019, but have not been triggered to date. If ASX participants meet the terms of their market making contracts, and there is sufficient participation by industry in the scheme, then there is unlikely to be any additional benefit in introducing alternative or additional market making schemes, although there would likely be higher costs.

3 In making this final determination, the Commission notes the results from the first two months of ASX market making are positive, while also recognising that participation in the scheme to date is less than was anticipated when the Commission's draft determination was published.

4 The early results show there are bids and offers available in all jurisdictions for most periods on trading days, including consistent end of day prices indicating the availability of contracts for trading. Prices posted by the market makers have been within the specified bid-ask spreads, and it has been notable that most trading has occurred within those price bands with participants other than the market makers.

5 There are two market makers participating in South Australia, which was the anticipated number of participants. This is important because that jurisdiction has low liquidity compared to other jurisdictions. At present, there is one market maker in each of New South Wales and Queensland, and no market makers in Victoria. These jurisdictions have adequate liquidity, but the Commission notes increased benefits likely would be achieved if additional market makers participate in the ASX scheme.

6 Based on the analysis undertaken in this determination and the early results of, and participation in, the ASX market making scheme the Commission considers the proposed rule would not, or would not likely, contribute to the National Electricity Objective (NEO). It has therefore decided not to make a final rule.

7 In the course of analysing this rule change request, the Commission identified specific information gaps that affect the ability of:

- participants or potential entrants to observe electricity derivative (contract) prices
- market bodies to assess the efficiency of the contract market and how it is working with the wholesale spot market.

8 The Commission will work with relevant market bodies and participants to help address these gaps, including:

- to improve the transparency of the over-the-counter (OTC) contract market

- to enhance the AER's powers to monitor contract market liquidity, including participants' adherence to the terms of the ASX market making scheme, and with reference to the structural characteristics of the electricity market in each jurisdiction.

Background

9 On 25 October 2018, ENGIE submitted a rule change request to the Commission. The rule change request proposed changes to the National Electricity Rules (NER) that would require the AER to operate a tender for the provision of market making services in the NEM.

10 Market making services are designed to improve liquidity. In general, a liquid market is one in which a participant can reasonably expect to buy or sell a contract, within a reasonable price range, without that trade moving the price unreasonably. Market makers offer to buy or sell a volume of contracts within specified price ranges, so that participants have the opportunity to buy or sell contracts to manage their risks. For retailers and large consumers, financial (or hedge) contracts can deliver certainty in wholesale electricity costs for a particular period, to protect them from high or volatile spot market prices. For generators, hedge contracts can underwrite their revenues and thereby support operational commitment or investment decisions.

11 Market making services can be voluntary, provided with incentives, or compulsory. There are many design options, but key elements commonly include, defined products, defined periods for market making, defined volumes and defined pricing.

12 In its Retail Electricity Pricing Inquiry (REPI) the Australian Competition and Consumer Commission (ACCC) recommended compulsory market making services be introduced in South Australia as a way to improve liquidity. The ACCC considered this would address concerns that South Australian retailers and large customers have had difficulty gaining contracts of the size, duration and price they would prefer. The Energy Security Board (ESB) was tasked with assessing that recommendation, but has postponed its assessment until this rule change is complete.

13 The rule change proponent does not agree with the ACCC, that compulsory market making services in South Australia are suitable. It considers the structural conditions in South Australia mean that jurisdiction will have lower levels of liquidity, and it questions whether vertical integration is a significant factor contributing to lower liquidity. In response, the proponent has put forward its alternative market making proposal, which is the subject of this rule change request.

14 In addition to the ASX market making and the RRO/MLO schemes, there are four other mechanisms that may impact on market liquidity in the near term.

- The Treasury Laws Amendment (Prohibiting Market Misconduct) Bill 2018 included:
  - a prohibition on generators from withholding, or limiting their offers for, electricity contracts with the aim of substantially lessening competition in the market
  - a power for the Treasurer to direct participants to provide market making services.

  While the Bill lapsed when parliament was dissolved in April 2019, the government has subsequently indicated it will re-introduce the Bill.

- The South Australian parliament also progressed a modification to the RRO framework under the National Electricity Law (NEL) and Rules, to provide the South Australian Energy Minister with the ability to make a T-3 Reliability Instrument under the RRO and, in turn, trigger the MLO process in that state. This also became operational on 1 July 2019, but has not been triggered by the South Australian government
- The commencement of the Default Market Offer (DMO) and Victorian Default Offer (VDO) on 1 July 2019 may have an effect on the contract market. Contracts help underwrite investment decisions, so investors prefer longer contracts that are more aligned to the life of the assets they are investing in. Contracts also protect retailers against the risk of wholesale costs being higher than the retail prices they have offered to consumers via market or standing offer contracts. A DMO/VDO that sets a cap on retail pricing, and that is set just before a financial year, may undermine both of the main benefits of contracts by encouraging a shorter rather than a longer term approach to hedging.
- FEX Global (Financial and Energy Exchange Group) is planning to commence operating an electricity futures exchange in the second half of 2019. It is expected to offer the same suite of electricity products as the ASX at commencement.

Summary of reasons

15 The Commission's final determination not to make a final rule is based on analysis that indicates market making arrangements additional to the ASX and RRO/MLO schemes are not likely to be efficient. On this basis, a rule to require additional market making services would not, or would not likely, contribute to the NEO.

16 Key findings include:

- Liquidity across the NEM is generally healthy. Liquidity in South Australia is much lower than in other regions. In particular, trading does not occur on a majority of days in South Australia whereas there are very few days without trading in other jurisdictions. Other metrics, including turnover, churn and bid ask spreads also indicate lower liquidity in South Australia.
- Initial data from the ASX market making scheme indicates bids and offers are available in all jurisdictions, within the specified pricing range at most times on trading days. There are also prices available at the end of day, indicating there are contracts available to trade. Despite the availability of contracts there is as yet no observable increase in the volume of trades or the number of days on which trading occurs.
- The structural characteristics of the South Australian market contribute to lower liquidity.
  - The available summer scheduled and semi-scheduled generation capacity of 4,408MW comprises 2,908MW of firm generation (87 per cent of which is gas generation) and 1,500MW of intermittent renewable generation. This means there are limited firm contracts offered, and because the firm contracts are predominantly from gas generators the prices tend to be higher than other NEM regions.
  - There is also a high level of vertical and horizontal integration which reduces the broader availability, and demand for, contracts.

    - Demand is relatively low, comprising 12TWh of the 196TWh in the NEM. Given there is significant rooftop solar and a high proportion of wind generation, demand and supply can vary significantly in a short time.
    - There is limited interconnection to Victoria, which can assist supply if unconstrained.

  These factors contribute to high spot price volatility, which influences the willingness of participants to provide contracts and the pricing of those contracts. Understanding the influence of structural factors on liquidity is critical when considering market making arrangements. In markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for a market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of regulatory assessment.

- The ASX and RRO/MLO schemes are expected to improve liquidity compared to the levels previously observable in the market. To date, the ASX scheme has improved the availability of prices for market making products, most notably in South Australia where two market makers are operating. It is too early to make conclusions about the impact of the market making scheme on liquidity in the NEM or in South Australia in particular. However, as discussed in the final determination, the Commission's expectation is that market making services should improve the availability of prices, narrow the bid-ask spreads, reduce the number of days without trades and increase trading volumes.
- The Commission engaged a consultant, NERA, to undertake an analysis of the incremental costs and benefits of additional market making requirements beyond the ASX and RRO/MLO schemes. The analysis modelled the four market making schemes described in the Consultation paper. The analysis concluded that if the ASX scheme delivers to its design, then there would be no additional benefit from additional market making schemes. The other schemes are also likely to have higher costs.

17 It is for these reasons that the Commission's final determination is not to make a final rule.

18 In making this final determination, the Commission notes the results from the first two months of market making are positive, while also recognising that participation in the scheme to date is less than was anticipated when the draft determination was published.

19 The early results show there are bids and offers available in all jurisdictions for most periods on trading days, including consistent end of day prices indicating the availability of contracts for trading. Prices posted by the market makers have been within the specified bid-ask spreads, and it has been notable that most trading has occurred within those price bands with participants other than the market makers.

20 There are two market makers participating in South Australia, which was the anticipated number of participants. This is important because that jurisdiction has low liquidity compared to other jurisdictions. Other jurisdictions, including New South Wales, Queensland and Victoria, have adequate liquidity historically, but the Commission notes additional market makers would likely deliver increased benefits and prevent future deterioration in liquidity.

Addressing information gaps in the market

21 In the process of assessing liquidity it became apparent that there are material information gaps in the contract market. The gaps undermine price discovery for participants, and the assessment of market conduct and performance by regulators.

22 Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration). The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as Power Purchase Agreements (PPAs), demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

OTC market transparency

23 The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format. The ESB has recently consulted with industry on this recommendation and has provided recommendations to the COAG Energy Council. It considered the preferable path is for the AEMC, AER and AFMA to work with market participants to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

24 In the final determination the Commission notes there are specific areas of the AFMA survey where improvement is required for it to adequately provide transparency of OTC trades. These include:

- **Price.** There is no price information in the AFMA survey. It is the main item that needs to be addressed in order to achieve transparency in the OTC market. The Commission understands this will also be the most contentious item for AFMA and its members to address with AFMA citing regulatory and compliance issues, problems dealing with non-standard contracts, the difficulty of accessing information that is not traded via a broker and issues of commercial sensitivity.
- **Coverage.** This relates to the number of participants, and the products covered. There are product gaps in the survey; in particular, PPAs, demand response and weather derivatives. There were also only fourteen participants in the last AFMA survey, although they represented the majority of market generation and load, and the two main financial traders.
- **Timeliness.** The AFMA survey is conducted annually and released some months after the end of the financial year. This significantly limits the usefulness of the data to industry. The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery.

25 The Commission agrees with the ESB's recommendation to COAG Energy Council, in relation to the establishment of an OTC repository, that an enhanced AFMA survey is the most effective way to improve transparency in the OTC market, and that the effectiveness of the survey should be reviewed after a suitable period.

26 In support of this approach, it is important to agree some threshold issues in the near term.

Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

27 In the event that an enhanced survey is unable to provide the threshold improvements in information that the Commission has identified, the Commission will concurrently work with the AER on alternative approaches to address information gaps in the OTC market.

28 The Commission also acknowledges the comments from a number of respondents to the draft determination, that reporting requirements on industry should be streamlined to reduce any time and compliance costs.

The AER's market monitoring function

29 The ACCC's REPI also recommended an expansion of the AER's wholesale market monitoring and reporting function under the NEL to include the contract market, and enhancing the AER's information gathering powers. The ESB also examined this recommendation and supported the ACCC's position. It recommended that the AEMC and AER work to draft law changes proposed to give effect to the AER's expanded function. The recommended law changes are to be provided to the Energy Council.

30 The Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. In particular:

- the AER will need to monitor whether participants in the ASX market making scheme adhere to the terms of their agreement , as an input into assessing the effectiveness of market making schemes in delivering liquidity. If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants' non-adherence or the scheme design. The absence of clear performance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity. Importantly, the AER does not have a formal role in monitoring compliance with the ASX scheme.
- in monitoring and reporting on market liquidity, the AER should take account of:
  - whether participants in the ASX market making scheme, and the MLO if triggered, meet the specified performance levels
  - the liquidity factors examined in this rule change process, at least including the availability of prices, the bid-ask spreads, the number of days with trading, and trading volumes
  - the structural characteristics of each jurisdiction.

31 The Commission will also work with the AER to determine whether large vertically integrated market participants should regularly report specific additional data to enable ongoing assessment of market conduct and performance. In the course of this rule change, the Commission has not attempted to examine the potential range of information that may be required to monitor and report on the contract market, but it has identified two specific areas for further consideration. These are:

- Information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting.
- Information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

32 These issues are commonly raised but there is poor data availability to enable assessment. The Commission will examine these issues more closely in conjunction with the AER as part of developing the proposed law changes to enhance the AER's market monitoring role.

The interaction of the contract and wholesale spot markets

33 As context for this rule change it is important to understand the interaction of the contract and wholesale spot markets.

34 The National Electricity Market (NEM) is an energy only market, where all generation is provided into a central pool, and all energy is purchased from the pool. AEMO operates the market by balancing supply and demand, and determining the price for the supply of wholesale electricity, every five minutes. The wholesale spot price is calculated every 30 minutes, and is the price that is paid by users for their consumption and to generators for their output. The spot price is the average of the six dispatch intervals that make up the 30 minute spot price period. A spot price is determined separately at a regional reference node within each region.

35 Spot market prices vary with changing demand and supply conditions, resulting in significant wholesale price variation in different regions, at different times of day, and different times of year. Spot market prices can range from the market price cap of $14,700/MWh to the market floor price of -$1,000/MWh.

36 The volatility of wholesale spot prices creates uncertainties for buyers and sellers in the market. The uncertainty relates to the expected cash flows of participants from buying or selling electricity. For example:

- a retailer needs to buy wholesale electricity in order to provide it to consumers. It will commonly contract with consumers to provide electricity at prices that are fixed for a given period, but will face uncertain and varying wholesale spot prices over that supply period.
- a generator needs to cover its operational (e.g. fuel) and investment (i.e. return of, and return on, capital) costs over time, but faces an uncertain and varying revenue stream.

37 Both participants face risk to their cash flows. In order to manage these risks, participants can enter into financial contracts. For example, the above retailer and generator can enter into a contract with an agreed price for the supply of an agreed quantity of electricity for a given period. In this way, the retailer gains certainty over its costs and the generator over its revenue.

38 The contract market:

- supports retail competition and market entry. It allows participants to test their business models in the market with some certainty over a significant component of their costs
- enables generators to commit to generating in particular periods and (at least) cover their short term costs
- helps underwrite investment, by reducing or managing the risk of investment in long-lived assets
- provides incentives for generators to maintain system reserves.[1]

39 Participants can also manage their risk physically, via vertical or horizontal integration.

Linking financial incentives to the system's physical needs: example

40 Assume a generator sells a swap contract to a retailer that limits the price the retailer pays to $60 per MWh. This means that irrespective of the spot price, or the amount of output the generator provides, the generator will receive $60 per MWh from the retailer (for the quantity of electricity agreed in the contract).

41 During price events where the spot price is above that agreed in the contract, the generator is incentivised to generate to the level of output agreed in the contract, to receive the high spot price for the agreed contract output and pass this through to the retailer. In return the generator receives the fixed price agreed in the contract. Where system reliability is stressed, for example during heat-waves, and prices are extremely high, the penalty for not being reliable is extreme.

42 For example, during a market price cap event, when the spot price is at its maximum $14,700, a generator that is contracted at $60 per MWh will lose $14,640 per MW per hour that it is not available, as it will be required to pay this amount to the retailer under the contract. For a 500MW unit, this equates to a loss of $7.3 million an hour.

1 For example a generator with four turbines may use two to supply its own retail load, offer contracts for the output of the third, while holding the fourth in reserve to account for an unexpected outage. In this way, it protects its contract position and provides system reserves capacity. Another generator may commit a higher proportion of its output to self-supply or contracting, depending on its business model and risk tolerance.

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TABLES

FIGURES

1 BACKGROUND

This chapter describes the policy and legislative context within which this rule change process is being conducted, and notes the risk of higher costs if multiple market making obligations operate concurrently.

1.1 The context within which this rule change is being assessed

There are a number of different market making schemes or proposals that are being progressed or considered at the same time as this rule change. Other market and regulatory developments that may impact on market making services are also described in this section.

1.1.1 Retailer Reliability Obligation

At the 26 October 2018 COAG Energy Council meeting, Ministers agreed that the ESB would progress development of amendments to the NEL that would give effect to the RRO. The RRO was a revised version of the National Energy Guarantee (NEG), in that it progressed the reliability but not the emission reduction requirements that were part of the original NEG design.

A consultation paper was published on 8 November 2018. To accompany the consultation paper, the ESB also released draft amendments to the National Electricity Rules (NER) and an illustrative timeline. On 8 March 2019, the ESB published the Retailer Reliability Obligation Draft Rules Consultation Paper and the final rules package to implement the RRO was approved by the COAG Energy Council on 4 June 2019. The RRO commenced on 1 July 2019.

The South Australian government also progressed a modification to the RRO framework under the National Electricity Law (NEL) and Rules, to provide the South Australian Energy Minister with the ability The South Australian government also progressed a modification to the RRO framework under the National Electricity Law (NEL) and Rules, to provide the South Australian Energy Minister with the ability to make a T-3 Reliability Instrument under the RRO and, in turn, trigger the MLO process in that state. This also became operational on 1 July 2019.o make a T-3 Reliability Instrument under the RRO and, in turn, trigger the MLO process in that state. This also became operational on 1 July 2019.

Although the prime focus of the RRO is to facilitate reliability, the associated MLO is a market making requirement, and therefore an important contextual factor in the assessment of this rule change.

On 30 August 2019, the AER released its Interim MLO guidelines, Interim Contracts and Firmness Guidelines and a final determination relating to the deemed MLO generators in Victoria. The Interim guidelines expanded the MLO products beyond quarterly and monthly products to include calender and financial year products. Approved products have also been reframed so they are not specific to any particular trading exchange.

1.1.2 ASX market making incentive scheme

In July 2018 the ASX commenced a process to introduce voluntary market making services in the electricity futures market.[2] Several physical participants expressed support for the scheme and, currently, three participants had signed up to the scheme. In return for providing market making services, participants receive discounted exchange fees and a share of profit from the increased value of trade driven by market making. Participants may also have been motivated to participate in the scheme in order to avoid further regulatory action, including compulsory obligations for market making.

The terms of the market making arrangement have been developed in parallel with those of the MLO, and are largely the same. It should be noted only baseload products are now included in the ASX market making scheme, whereas baseload and cap products are covered under the MLO.[3]The ASX in discussion with the Commission indicates that market makers have also been making markets in caps in most regions. A comparison of the key features and requirements of the two schemes is available in appendix f.

The scheme commenced on 1 July 2019.

1.1.3 ACCC REPI recommendation 7 and ESB advice

The ACCC reviewed the contract market in the REPI.[4]It found that in certain regions of the NEM, particularly South Australia, the level of market liquidity and the advantages afforded by vertical integration mean that it is difficult for new entrants or smaller retailers to compete effectively in the market.

The ESB was asked to provide advice on the ACCC recommendation, and on 28 September 2018 published a consultation paper on Market Making Requirements in the NEM. The paper sought industry submissions on a proposal to create a MLO that combined the reliability requirement under the NEG with the liquidity requirement under the ACCC's REPI recommendation 7.[5]

The ESB has deferred further work on this recommendation until after this rule change process is complete.

1.1.4 Commonwealth legislation

In 2018 the Treasurer introduced the *Prohibiting Energy Market Misconduct Bill* to Parliament. The legislation was referred to a Senate Committee before being lapsing on dissolution of the

2 Expressions of interest for Australian Electricity Market Making, https://www.asxenergy.com.au/newsroom/industry_news/market-making-expression-of-

3 Caps are currently trading up to Q2 2021. Five minute settlement is scheduled to commence on 1 July 2021, which is the start of Q3 2021. Currently there are no five minute cap products available on the ASX, and it is understood none are trading in the OTC market.

4 ACCC Retail Electricity Pricing inquiry Final Report, https://www.accc.gov.au/publications/restoring-electricity-affordabilityaustralias-competitive-advantage

5 ESB consultation paper: Market Making Requirements in the NEM, September 2018, http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Market%20Making%20Requirements%20in%20the%20NEM%20Consultation%20Paper.pdf

parliament in April 2019. Since being re-elected, the government has indicated it will re-introduce the Bill.[6]

The Bill set out three kinds of prohibited conduct in relation to:

- retail prices
- the electricity financial contract market
- the wholesale electricity market.

Under the proposed Bill the ACCC may recommend that the Treasurer make an order that would require an electricity company to offer electricity financial contracts to third parties. This can be done if the ACCC reasonably believes that a person has engaged in prohibited conduct in relation to the electricity contract market or wholesale electricity market. It is intended that the making of a contracting order by the Treasurer would only occur in respect of more serious contraventions.

1.1.5 Competition in exchange services

FEX Global (Financial and Energy Exchange Group) is planning to commence operating an electricity futures exchange in the second half of 2019. It has advised it will offer the same suite of electricity products as the ASX at commencement.

Competition in exchange services has the potential to improve contract market liquidity. Product offerings and fee structures may diverge over time, potentially providing a broader suite of products and options to participants.

1.1.6 The Default market offer and Victorian default offer

The commencement of the Default Market Offer (DMO) and Victorian Default Offer (VDO) on 1 July 2019 may have an effect on the contract market.

Contracts help underwrite investment decisions, so investors prefer longer contracts that are more aligned to the life of the assets they are investing in. Contracts also protect retailers against the risk of wholesale costs being higher than the retail prices they have offered to consumers via market or standing offer contracts.

Given the DMO and VDO set caps on the level of retail pricing that is allowed, and those prices are scheduled to be set just before each financial year, the process may encourage a shorter rather than longer term approach to hedging. For example, retailers will be less likely to commit to wholesale contracts until they know what prices they are allowed to charge consumers. This may undermine generator attempts to sell longer term supply contracts.

Historically, where regulatory pricing has existed in the NEM, prices tended to be set for three years, and retailers as a consequence had more certainty to contract for wholesale contracts and retail customers over longer time frames.

6 see The Australian, 29 May 2019.

1.2 Risks of layered market making obligations

The Commission notes that with multiple processes potentially allowing for the introduction of market making, there is a risk that separately layered arrangements may increase the overall costs of market making.

At present there is an industry led process to work with the ASX in addition to the RRO/MLO scheme. While it may be assumed that there will be a reasonable coincidence of the market makers under each scheme, this is not assured given the different mechanisms used to identify the market makers.

If an incentivised scheme was operating alongside the RRO/MLO, there is a strong probability that the coincidence of market makers would fail. This is because financial participants would likely participate in an incentivised scheme, whereas the RRO/MLO is restricted to physical market operators.

In practice this could result in incentivised participants receiving the incentive payment for market making, and then seeking additional payment from participants captured by the RRO/MLO scheme to meet the MLO on their behalf. Any additional payment would represent an increase in the social cost of market making.

2 THE RULE CHANGE REQUEST

On 25 October 2018, ENGIE proposed a rule change to require the AER to operate a tender for the provision of market making services in the NEM. The proponent stated this is the most appropriate method for identifying parties who have the sophistication and appetite to take on the risks associated with market making.

The rule was proposed as a preferable alternative to the compulsory market making proposals that were outlined in the ACCC REPI report and the ESB consultation paper on *Market Making Requirements in the NEM*.[7]

Copies of the rule change request may be found on the AEMC website, www.aemc.gov.au.

2.1 Rationale for the rule change request

The proponent lodged the rule change request:

- to enable more detailed consideration of the appropriateness of a mandatory market making mechanism
- to propose an alternative approach that seeks to manage the issues with a compulsory obligation that it claims were identified (but not addressed) in the ACCC's REPI and in the ESB's consultation paper on Market Making Requirements in the NEM.

The proponent argued that several fundamental questions around the justification for market making obligations, either in South Australia or more broadly, have not been adequately addressed. In particular, it noted concerns with the diagnosis of liquidity and market failure, and raised concerns about a compulsory market making requirement.

2.1.1 Issues with the diagnosis of the problem and market failure

The proponent accepted that some retailers may have difficulty obtaining contracts of the size, duration and price they would prefer, but also suggested some generators and hedge providers may have difficulty finding buyers for contracts on the terms they desire. It considers neither of these factors is necessarily grounds for concluding there has been market failure.

The proponent suggested that the case has not been sufficiently made that vertical integration is the primary (or even a significant) contributor to the problems faced by both sides of the market in South Australia. The proponent did not feel that the South Australian market conditions have been effectively diagnosed, particularly compared to other states. It also did not consider that an adequate link had been demonstrated to conclude market making as proposed by the ACCC and ESB will solve those problems.

The proponent considers the structural characteristics of the South Australian market need to be analysed to understand the hedging market. It is a small market with a high penetration of renewable generation, reliant on gas generation to provide firm capacity and with important interconnection with the Victorian market. The proponent rejects the suggestion

7 ESB consultation paper: *Market Making Requirements in the NEM*, September 2018.

that vertical integration has led to the withholding of hedge products from competing retailers. It claimed there is no evidence of such behaviour, particularly in an environment of rising prices. It also pointed out that the ACCC REPI acknowledged the prices for trades of bigger and smaller participants in South Australia were largely the same.

The importance of gas generation to electricity generation in South Australia was also noted. The proponent maintained that the lack of gas market liquidity in terms of the ability to enter and exit positions, the size of contracts, the tenure of contracts and the lack of standardisation of contracts has a direct bearing on the liquidity of electricity contracts. It was stated that a gas generator should not be expected to provide the same level of liquidity as a coal-fired generator. ENGIE considered this issue was not adequately addressed in either the ACCC REPI or in the ESB consultation paper on market making requirements in the NEM.

The proponent considers the experience of firm generators in South Australia contrasts with the conclusions of the ACCC REPI, in that it highlights the difficulty some firm generators have had in securing contracts. Significant effort was made by the last coal-fired generator (Northern) to sell contracts but the absence of parties willing to buy contracts contributed to its closure. This was also the case prior to a unit of Pelican Point being withdrawn from the market in 2015 (the unit subsequently returned in 2017). The proponent noted that one of the key drivers of the NEG was to encourage large customers to contract to avoid the retirement of firm generators. The proponent suggested the theory has now been turned on its head, with arguments of contract withholding by vertically integrated retailers taken as justification for market making.

The rule change request pointed out that during the current deliberations on the future of the UK scheme, Ofgem has acknowledged the findings by the Competition and Markets Authority that they "have not identified any areas in which vertical integration is likely to have a detrimental impact on competition for independent suppliers and generators".[8]

The rule change request suggested a more detailed analysis of these issues was required in South Australia and more broadly across the NEM.

2.1.2 Issues with a compulsory obligation

The proponent identified a number of issues with a compulsory market making obligation. Introducing a requirement that will force specific market participants with physical generation to buy and sell contracts that they would be unwilling to trade freely, due to a lack of financial incentives and an unwillingness to take on additional risk is, in the view of the proponent, a significant change in the operation of the NEM.

Where contractual terms may be unfavourable for either party, it is not appropriate for one party to be obliged to accept those terms or conditions. Requiring a party to take on additional risk or offer hedges below cost will undermine asset viability and work to destabilise the market, in South Australia and more broadly. A compulsory obligation fails to examine the impacts on disadvantaged parties and to appreciate the long term effects on the market.

8 Rule change request p.5.

The proponent identified a number of problems with a compulsory obligation:

- the overall risk capacity in the market is unlikely to increase, with participants having to adjust their risk position for additional hedges they are required to offer
- obliging some participants to trade with lower credit quality parties will likely increase costs for consumers
- an obligation may not benefit the small retailers it is intended to help if trade sizes are not small enough. Standard futures contracts are also relatively blunt instruments for a small retailer without scale. Smaller retailers, according to the proponent, tend to set up more tailored arrangements that match the needs of their portfolio. The larger participants who provide these products will have to adjust their risk exposure to allow for an obligation
- physical players have operating and financial risk constraints. An obligation will not increase their overall capacity to manage risk
- the proponent suggests an obligation to provide hedges outside an integrated portfolio may actually reduce the level of contracts available in the market given integrated participants have more of a natural hedge when they trade with themselves and so may be willing to offer more capacity when trading on this basis
- operating constraints such as generator outages and fuel supply constraints, for example a lack of liquidity in gas contracts, may constrain a generator below the full extent of their capacity
- it is not appropriate for obligated parties to take on unnecessary costs. Obligated parties may find it difficult to move prices during periods of high volatility, thereby resulting in significant and unexpected costs. A market making obligation may also involve significant IT costs
- current Australian Financial Services Licence arrangements prohibit participants in a market from being a market maker unless they are licensed to do so
- a compulsory obligation may undermine the business case for the voluntary market making incentive scheme being developed by the ASX.

2.2 Proposed solution

2.2.1 Proposed rule

The rule change request proposed that a tender be run by the AER for voluntary market making services in the National Electricity Market (NEM).[9] The proponent maintained that this is the most appropriate method for identifying parties who have the sophistication and appetite to take on the risk associated with a market making service. The proponent suggested the tender should:

- be conducted every three to five years
- cover all regions in the National Energy Market (NEM)

9 Rule change request p.8.

- allow the market making arrangement to remain in place on an ongoing basis with no trigger mechanism
- specify parcel sizes, required cumulative exposure, required spreads and periods of offer for each region that will remain in place for the full duration of the tender period
- be open to financial or other providers
- permit the successful tenderer to sub-contract directly with physical and financial market participants in order to provide the market making service
- require the successful tenderer to manage the risk of default in participants' market making positions
- provide flexibility in relation to both ASX and OTC products
- recover the costs of the tender from customers
- prescribe penalties for non-performance
- specify the market monitoring required, noting that this may depend on the type of product used to meet the obligation
- be reviewed by the AEMC in advance of each re-tender.

The tender would be independent of the NEG reliability obligation[10], and therefore any market making obligations proposed by the NEG should be considered unwarranted.

The rule change proposal also referred to the ASX Market Making Incentive Scheme and suggested complementing this scheme based on voluntary participation as an important consideration.

2.2.2 Contribution to the NEO

The proponent stated that proposals to require compulsory market making arrangements have not examined the impacts on disadvantaged parties (such as the increased risk of loss given default) or the long-term effects (such as a disincentive to invest or potential early asset retirements) the arrangement may have. A tender for voluntary market making services would not create these additional risks for existing market participants and would provide a new service in the market with parties willing to take on the additional risk for a price.

The proponent concluded the proposed rule change is in the long term interests of customers and promotes a number of beneficial outcomes consistent with the NEO that would not be provided by a compulsory market making arrangement.

2.2.3 Benefits described by the proponent

The proponent considered there would be a range of benefits if the proposed market making scheme was implemented.

- *An economically efficient allocation of risk in the NEM* — the allocation of risk would be managed by sophisticated financial intermediaries that are effective at handling and

10 This is now the Retailer Reliability Obligation

pricing financial risk. This would facilitate the management of new entrant retailers without placing unmanageable risks on selected physical participants.

- *Commercial drivers not distorted* — the commercial drivers underpinning participants' hedge positions would not be distorted.
- *Transparency and cost recovery* services provided outside of the physical market would be provided transparently and with appropriate cost recovery.
- *Investor confidence in the market*— shareholder and investor expectations would not be under-mined by compulsory market making obligations. This would avoid placing additional risk premiums on investment in some or all regions of the NEM to account for unmanageable risks and unrecoverable costs.
- *Encourages participation of specialist providers* — the proposed rule may encourage the entrance of specialist providers who may be better placed to provide market making services.
- *Contracting consistent with capability* — it should minimise the potential for entities to provide risk management services beyond their capability to do so, or to provide hedges beyond the financial capability of the underlying generation asset.
- *Obligatory mechanism unwarranted* — the proposal minimises the need for market intervention as proposed under the NEG.
- *Certainty provided by an ongoing mechanism* — an ongoing mechanism, with firm terms set for each three to five year period, removes the uncertainty that would be created by a trigger mechanism.
- *Greater confidence in the NEM and related markets* — a voluntary market making arrangement will promote confidence in the NEM and closely related markets, for example gas and large generation certificates (LGCs).

2.2.4 Costs described by the proponent

The costs of the tender and the costs of participants taking part in the tender and meeting those obligations over a three to five year timeframe were not set out in the rule change proposal. However, the proposal suggested that the costs of the tender be "recovered from customers".[11]

2.3 The rule making process

On 20 December 2018, the Commission commenced the rule making process and published a consultation paper on the issues raised by the proponent.[12]

Submissions to the consultation paper closed on 7 February 2019. Fourteen submissions were received. All issues raised by stakeholders were considered and responded to in the draft rule determination which can be found on the project website https://www.aemc.gov.au/rule-changes/market-making-arrangements-nem.

11 ENGIE rule change request, p.9

12 The notice of commencement was published under s.95 of the National Electricity Law (NEL).

On 27 June, the Commission published a draft determination. Submissions on the draft determination closed on 8 August. The Commission received five submissions and six late submissions to the draft determination.

The Commission considered the issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to in appendix b.

3 FINAL RULE DETERMINATION

3.1 The Commission's final rule determination

The Commission's final rule determination is to not make the proposed rule.

The Commission's reasons for making this decision are set out in section 3.5 (and in more detail in the relevant chapters and appendices).

This chapter outlines:

- the rule making test for changes to the National Electricity Rules (NER)
- the assessment framework for considering the rule change request
- potential legal issues with making a rule
- a summary of reasons for not making a final rule.

Further information on the legal requirements for making this final rule determination is set out in appendix a.

3.2 Rule making test — achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[13] This is the decision-making framework that the Commission must apply.

The NEO is:[14]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The Commission has identified that the relevant aspects of the NEO are the efficient investment in, and efficient operation and use of, electricity services with respect to the price and reliability of supply of electricity.

3.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered the following principles:

- **Enhance transparency and predictability**: The transparency of information is a key feature of the efficient operation of the NEM. Market participants need access to clear, timely and accurate information in order to allow them to make efficient commercial and operational decisions. The Commission has considered the degree to which a market making service could make market participants more confident in contract prices.

13 Section 88 of the NEL.

14 Section 7 of the NEL.

- **Enhance wholesale and retail market competition**: The greater ability to trade in electricity futures contracts at prices that are visible to all market participants helps to lower barriers to entry and competition both in the wholesale and retail market. TheCommission has considered the degree to which this will help to improve price outcomes for consumers.
- **Efficiency of investment in and retirement of generation capacity and demand response:** Improving the provision of information, transparency and predictability of information in the NEM can assist in promoting efficiency of investment in, and operation of, generation capacity and demand response decisions. By improving the provision of information, this can potentially help energy market participants to make more efficient decisions.
- **Administrative costs**: Market making arrangements could impose new costs on both participants and the party or parties administering the arrangements.

3.4 Potential legal issues with making a rule

As part of assessing the rule change request, the Commission has considered what (if any) legal issues may arise in relation to making a Rule to introduce a market making mechanism. While the Commission has determined not to make a final rule, the following legal matters were identified when assessing the rule change request:

- **Rule-making power** – The Commission considers that a market making mechanism would likely fall within the scope of the Commission's rule-making power under section 34(1)(a)(iii) of the National Electricity Law.[15] However, the Commission is unlikely to have sufficient rule-making power to introduce a market making mechanism that regulates financial intermediaries (that is, the mechanism would need to be limited to parties that participate in the wholesale exchange).
- **Conferral of functions on the AER** – If the market making mechanism involved the AER running a tender process for market making in the NEM (or otherwise involved the AER administering some aspect of the mechanism), it is likely that such a role would constitute conferring a function or power on the AER under the Rules. While the Commission can confer additional function or powers on the AER under the Rules, the conferral of any new function or power also requires the unanimous agreement of the COAG Energy Council.[16] Also, depending on the exact form of the mechanism, there may be limitations on the AER's ability to hold funds under the mechanism (e.g. if it involved incentive payments being made to market makers) or enter into contracts with market makers.

15 Section 34(1)(a)(iii) of the NEL provides that the Commission may make rules "for or with respect to… regulating… the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system… ".

16 AER (as a Commonwealth body) may only perform functions conferred by a State law (e.g. the National Electricity Law) if a Commonwealth law authorises the AER to perform those functions. The *Competition and Consumer Act 2010* (Cth) ("CCA") authorises the conferral of functions on the AER under State law if (and only if) the conferral is "in accordance with the Australian Energy Market Agreement…" (s. 44AI of the CCA). Certain functions are granted to AER under clause 9 of the Australian Energy Market Agreement (AEMA), which include functions related to economic regulation, regulation of Retail Energy Markets and "*such other functions as may from time to time be agreed unanimously by the MCE Ministers representing the Parties that have elected to be subject to the jurisdiction of the AER and are conferred by legislation*".

- **Australian financial services license ('AFSL')** – A party making offers to buy or sell derivatives under a market making mechanism will likely need to hold an AFSL. The form of any rule introducing a mandatory market making mechanism would need to take into account a party's ability to hold the requisite licence to perform its obligations under the mechanism.

The above reflect threshold legal issues with introducing a market making mechanism. Additional legal matters would likely need to be considered depending on the exact form of the mechanism.

3.5 Summary of reasons

The Commission's final determination not to make a final rule is based on analysis which indicates that market making arrangements additional to the ASX and RRO/MLO schemes are not likely to be efficient. (See appendix e for a summary of this analysis). On this basis, a rule to require additional market making services would not, or would not likely, contribute to the NEO.

Key findings include:

- Liquidity across the NEM is generally healthy. Liquidity in South Australia is much lower than in other regions. In particular, trading does not occur on a majority of days in South Australia whereas there are very few days without trading in other jurisdictions. Other metrics, including turnover, churn and bid ask spreads also indicate lower liquidity in South Australia.
- Initial data from the ASX market making scheme indicates bids and offers are available within the specified pricing range at most times on trading days. There are also prices available at the end of days, indicating there are contracts available to trade. Despite the availability of contracts there is no apparent increase in the volume of trades or the number of days on which trading occurs.
- The structural characteristics of the South Australian market contribute to lower liquidity. (See appendix d on the structural factors impacting liquidity)
    - The available summer scheduled and semi-scheduled generation capacity of 4,408MW comprises 2,908MW of firm generation (87 per cent of which is gas generation) and 1,500MW of intermittent renewable generation. This means there are limited firm contracts offered, and because the firm contracts are predominantly from gas generators the prices tend to be higher than other NEM regions.
    - There is also a high level of vertical and horizontal integration which reduces the broader availability of contracts.
    - Demand is relatively low, comprising 12TWh of the 196TWh in the NEM. Given there is significant rooftop solar and a high proportion of wind generation, demand and supply can vary significantly in a short time.
    - There is limited interconnection to Victoria, which can assist supply if unconstrained.

  These factors contribute to high spot price volatility, which influences the willingness of participants to provide contracts and the pricing of those contracts. Understanding the influence of structural factors on liquidity is critical when considering market making arrangements. In markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for a market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of regulatory assessment.

- The ASX and RRO/MLO schemes are expected to improve liquidity compared to the levels previously observable in the market. To date, the ASX scheme has improved the availability of prices for market making products, most notably in South Australia where two market makers are operating. It is too early to make conclusions about the impact of the market making scheme on liquidity in the NEM or in South Australia in particular. However, as discussed in the draft determination, the Commission's expectation is that market making services should improve the availability of prices, narrow the bid-ask spreads, reduce the number of days without trades and increase trading volumes.
- The Commission engaged a consultant, NERA, to undertake an analysis of the incremental costs and benefits of additional market making requirements beyond the ASX and RRO/MLO schemes. The analysis modelled the four market making schemes described in the Consultation paper. The analysis concluded that if the ASX scheme delivers to its design, then there would be no additional benefit from additional market making schemes. The other schemes are also likely to have higher costs. (See appendix e for the cost benefit analysis of market making schemes).

It is for these reasons that the Commission's final determination is not to make a final rule.

3.5.1 Addressing information gaps in the market

In the process of assessing liquidity it became apparent that there are material information gaps in the contract market. The gaps undermine price discovery for participants, and the assessment of market conduct and performance by regulators.

Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration). The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as PPAs, demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

OTC market transparency

The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format. The ESB has recently consulted with industry on this recommendation and has provided recommendations to the COAG Energy Council. It considered the preferable path is for the AEMC, AER and AFMA to work with market participants to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

The Commission has examined the AFMA survey and notes there are specific areas where improvement is required for it to adequately provide transparency of OTC trades. These include:

- **Price.** There is no price information in the AFMA survey. It is the main item that needs to be addressed in order to achieve transparency in the OTC market. The Commission understands this will also be the most contentious item for AFMA and its members to address.
- **Coverage.** This relates to the number of participants, and the products covered. There are product gaps in the survey; in particular, PPAs, demand response and weather derivatives. There were also only fourteen participants in the last AFMA survey, although they represented the majority of market generation and load, and the two main financial traders.
- **Timeliness.** The AFMA survey is conducted annually and released some months after the end of the financial year. This limits the usefulness of the data to industry. The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery.

The Commission agrees with the ESB's recommendation to COAG Energy Council, in relation to the establishment of an OTC repository, that an enhanced AFMA survey is the most effective way to improve transparency in the OTC market, and that the effectiveness of the survey should be reviewed after a suitable period.

In support of this approach, it is important to agree some threshold issues in the near term. Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

In the event that an enhanced survey is unable to provide the threshold improvements in information that the Commission has identified, the Commission will concurrently work with the AER on alternative approaches to address information gaps in the OTC market.

The Commission also acknowledges the comments from a number of respondents to the draft determination, that reporting requirements on industry should be streamlined to reduce any time and compliance costs. It will consider this issue in working the AER and industry on any revised reporting requirements.

The AER's market monitoring function

The ACCC's REPI also recommended an expansion of the AER's existing wholesale market monitoring and reporting functions under Division 1A, Part 3 of the NEL to include the contract market, and enhancing the AER's information gathering powers. The ESB also examined this recommendation and supported the ACCC's position. It recommended that the AEMC and AER work to draft law changes required to give effect to the AER's expanded role. The recommended law changes are to be provided to the Energy Council.

The Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. In particular:

- the AER will need to monitor whether participants in the ASX market making scheme adhere to the terms of the agreement, as an input into assessing the effectiveness of market making schemes in delivering liquidity. If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants' non-adherence or the scheme design. The absence of clear performance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity. From 1 July 2019, the AER has had powers to monitor compliance with the MLO. It will also need to be able to monitor participant performance in the ASX market making scheme.
- in monitoring and reporting on market liquidity, the AER should take account of:
  - whether participants in the ASX market making scheme, and the MLO if triggered, meet the specified performance levels
  - the liquidity factors examined in this rule change process, at least including the availability of prices, the bid-ask spreads, the number of days with trading, and trading volumes
  - the structural characteristics of the electricity market in each jurisdiction.

The Commission will also work with the AER to determine whether large vertically integrated market participants should regularly report specific additional data to enable ongoing assessment of market conduct and performance. In the course of this rule change, the Commission has not attempted to examine the potential range of information that may be required to monitor and report on the contract market, but it has identified two specific areas for further consideration. These are:

- Information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting.
- Information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

These issues are commonly raised but there is poor data availability to enable assessment. The Commission will examine these issues more closely in conjunction with the AER as part of developing the proposed law changes to enhance the AER's contract market monitoring role.

4 ASSESSING LIQUIDITY IN THE CONTRACT MARKET

This chapter:

- defines liquidity and the key metrics assessed in this determination
- provides an update on the assessment of liquidity in NEM jurisdictions
- assesses the performance of the ASX market making scheme to date
- discusses areas to improve contract market visibility.

4.1 Defining liquidity

Liquidity is a broadly used term, but there is not a standardised definition. In general, a liquid market is one in which a participant can reasonably expect to trade (prices for products are available most of the time), within reasonable bid-ask spreads, without that trade moving the price unreasonably. Put another way, liquidity is a measurement of the ease with which, in the absence of new information altering an asset's fundamental price, large volumes of the asset can be bought or sold quickly at a reasonable price. In practice, the broad definition of liquidity means assessments should be referenced against a range of indicators. Reliance on individual indicators risks misunderstanding the level of liquidity in a market.

Liquidity should also be observed over time, in particular to assess whether increases or declines in liquidity in one market are offset by increases or decreases elsewhere. For example whether declining liquidity on the ASX is offset by increasing liquidity in OTC trading or the demand response register.

The metrics described below provide a useful indication of liquidity in different NEM jurisdictions, but it is noted that the data available to the Commission is incomplete and additional insights may be available from a richer data set. Notably, the detailed data the ACCC collected from participants via its information gathering powers as part of the REPI was not available to the Commission.[17] The metrics used to assess liquidity in the final determination are:

- The availability of bid and offers to trade products, including the availability of end of day pricing - which provides an indication of the ability of participants to trade.
- The number of days in which trading occurred — this provides an indication of the ease with which participants have been able to buy or sell contracts and whether contract prices are attractive in addition to being available.
- The average number of transactions each day — this provides another indication of the level of contract trading activity.
- Contract turnover and churn — these metrics demonstrate actual volumes traded, and volume traded as a proportion of total demand in each region. High churn ratios indicate the physical demand for electricity has been traded many times over, and give traders confidence that prices reflect current market conditions and expectations. Conversely, low churn ratios may indicate 'stale' prices and reflect a lack of confidence from traders that

17 The ACCC stated legal reasons prevented it from sharing data with the AEMC.

the price reasonably reflects market conditions. Churn metrics may need to allow for a number of structural and market factors before meaningful comparisons are made between regions or regarding trends in churn over time. (See appendix I for commentary on the shortcomings of the churn metric and adjustments that would improve the usefulness of the metric).

- Bid-ask spreads — this is the difference between a seller's asking price and a buyer's bid price for a contract. The spread represents the cost of trading in and out of positions in the market (transaction costs). It is a useful metric in that it captures both explicit transaction costs, which relate to expenses such as order processing costs and taxes associated with trades, and implicit transaction (execution) costs. In general, higher transaction costs reduce the demand for trades and encourage traders to seek OTC or physical alternatives (such as vertical integration) to hedge their spot price risks.

In the draft determination measures of the availability of prices were not available to the Commission. Following commencement of the market making scheme, the ASX has made this data and this has allowed comparisons to be made between the availability of prices before market making was introduced and in the two months hence. This measure is useful in that it indicates both the ability of participants to trade and the availability of pricing information on a continuous basis to market participants, and to new entrants and other stakeholders who may not trade in the market on a daily basis.

In its submission to the draft determination AGL highlighted a range of additional metrics that it says should be considered as part of analysis of liquidity. These metrics included:

- the depth of bids and offers in the market
- the time bids and offers are listed
- the number of market participants

The Commission will consider these metrics with the AER in relation to how the AER will monitor the contract market over time.

4.2 Liquidity in the NEM - update

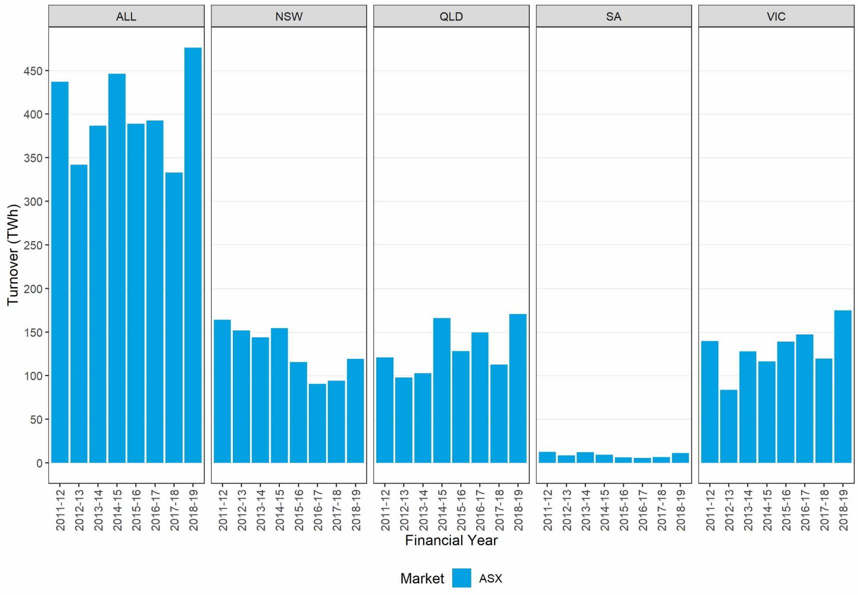
As was noted in the draft determination, liquidity levels in Queensland, New South Wales and Victoria are healthy in respect of a broad range of metrics including turnover, churn, bid ask spreads and the extent to which trade occurs on most days. This is not the case in South Australia.

In the 2018-2019 financial year liquidity in ASX traded products improved in all jurisdictions. However, conclusions from the data must be informed by the yet-to-be-published AFMA data on OTC trades. The two data sets provide an aggregate view of market trading, and the relative volume of trading in each market. Notably the aggregate data does not provide information on specific contract types including PPAs, demand response and weather derivatives.

Figure 4.1 below shows the contract volumes traded on the ASX in each NEM region. There were increases in ASX turnover in all regions in the 2018-19 financial year.

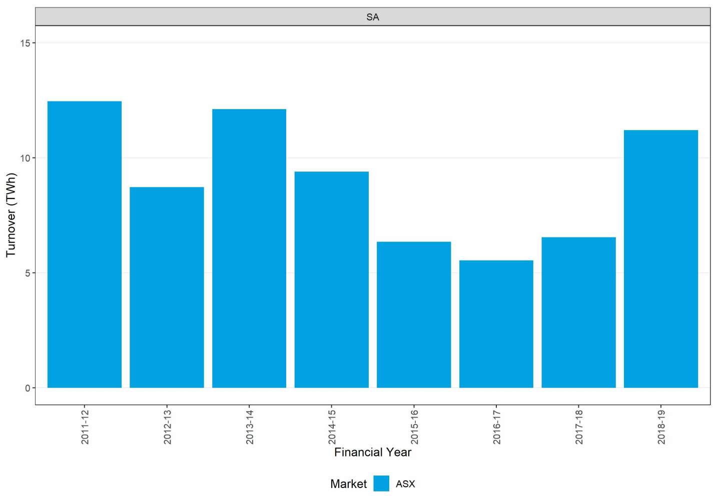
Figure 4.2 reflects that ASX turnover in South Australia has increased in 2018-19 compared to 2017-18.

Figure 4.1: ASX turnover by financial year



Source: ASX data

Figure 4.2: ASX turnover (South Australia) by financial year



Source: ASX data

4.3 Assessing the performance of the ASX market making scheme

The success of the scheme to date can be measured both with reference to participation and adherence to the key terms of the market making arrangement, and also with reference to the impact, in the first few months of operation, on the key liquidity metrics set out in this final determination.

4.3.1 Participation in the scheme

The number of participants in the ASX market making scheme is fewer than was anticipated in the draft determination and as modelled by NERA. Figure 4.3 shows the market makers in the ASX scheme, and those initially subject to the MLO if triggered. Whereas the NERA modelling assumed two in South Australia and four in other jurisdictions, at scheme commencement there were two in South Australia, one in both New South Wales and Queensland, and no market makers in Victoria.

Figure 4.3: ASX market making scheme: participants table

Market making participants (as at 2 September 2019)	AGL	Origin	Stanwell	CS Energy	Snowy	EA	ENGIE	Total
MLO groups (internal estimate - if RRO triggered)								
QLD			Stanwell	CS Energy				2
NSW	AGL	Origin			Snowy			3
VIC	AGL				Snowy	EA		3
SA	AGL	Origin					ENGIE	3
Total								7
Number of Market making scheme participants as at 2 September								
Number by state								
QLD								1
NSW								1
VIC								0
SA								2
Total								3
List of participants								
AGL								
Origin								
Stanwell								

Source: AEMC, ASX

Note: Some participants prefer to remain anonymous in relation to the jurisdiction in which market making services are provided

4.3.2 Use of exemptions under the scheme

Under the terms of the market making agreement, each market maker is provided with ten periods per month where they do not have make markets but still remain eligible for the incentives in the scheme. An exemption may relate to a failure to offer a contract for one of three tests: volume, time, and spread.

Since commencement the total market maker exemptions have been:

- 11 in July
- 2 in the period 1-15th August

There were 46 trading sessions for July across 3 trading zones. Each session had a total of 16 contracts offered in each region, or 736 contracts/region/month.

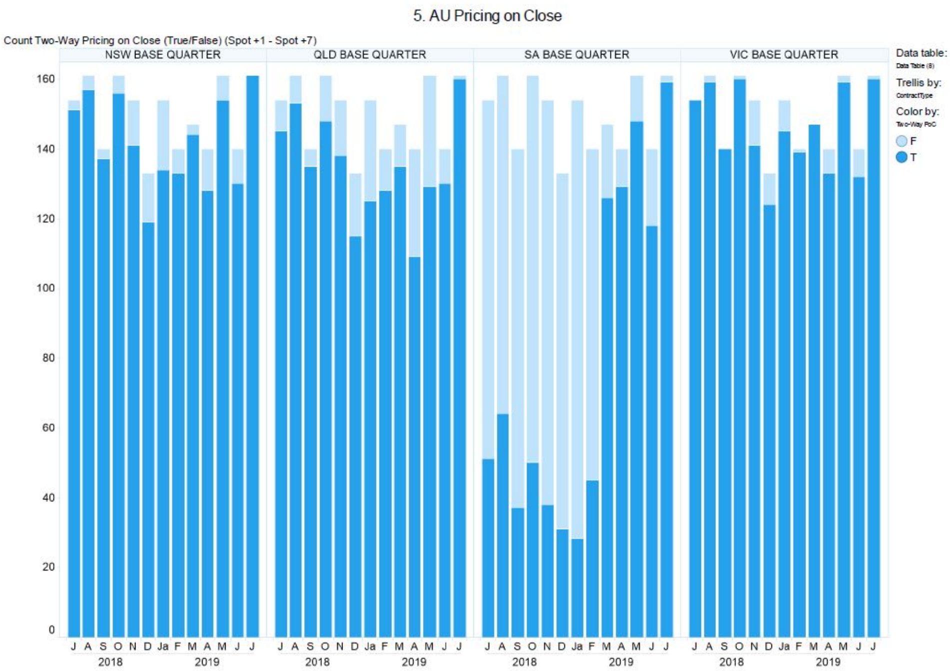
The exemptions in July were, in the view of the ASX, primarily a result of market makers bedding down the price provision technology. In August to date, the exemption rate is very low. The Commission notes that while these figures, and the trend in these figures, are encouraging, the market has not experienced a period of high volatility since the market making scheme was introduced.

4.3.3 Availability of bids and offers

In spite of a lower level of participation than was anticipated, the market making scheme has improved the availability of prices across products, both within the market making windows, and outside those periods.

The chart below shows that since market making began in July, prices in market maker products have been made in most periods. The ASX has advised the Commission that the observable increase in market making in South Australia since March was due to market makers under the scheme commencing to make prices in advance of the 1 July start date.

Figure 4.4: Price provision at close in market making scheme products

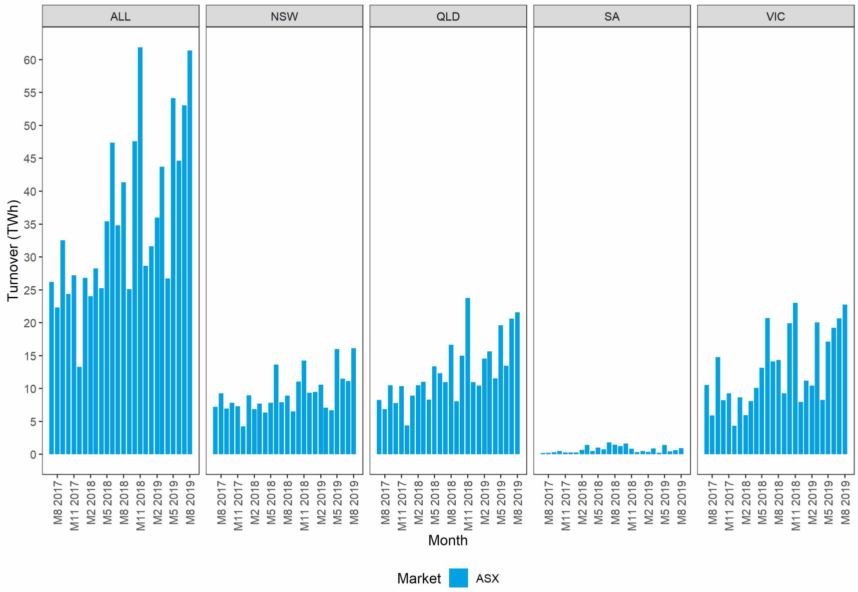


Source: ASX

4.3.4 Turnover

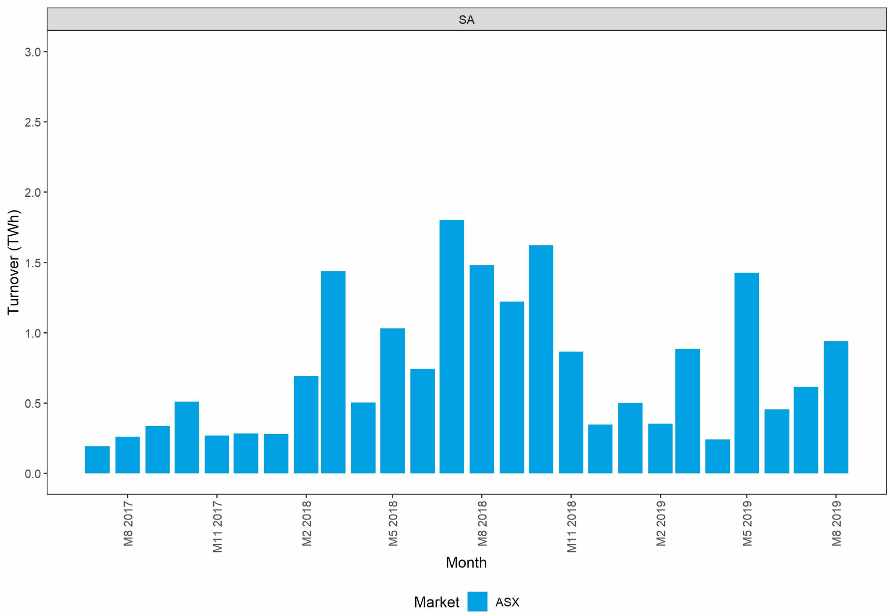
Contract turnover is observable in Figure 4.5. There was no step change in turnover from 1 July, but increased turnover is evident from May. It is too early in the operation of the market making scheme to draw conclusions on any metrics, even while some early signs are encouraging.

Figure 4.5: ASX Monthly turnover - all products



Source: ASX
Note: Chart shows 24 months prior to market making commencement and first two months turnover since commencement of market making scheme. M8 2019, refers to Month (August) and Year (2019) of trade

Figure 4.6: ASX monthly turnover - South Australia - all products

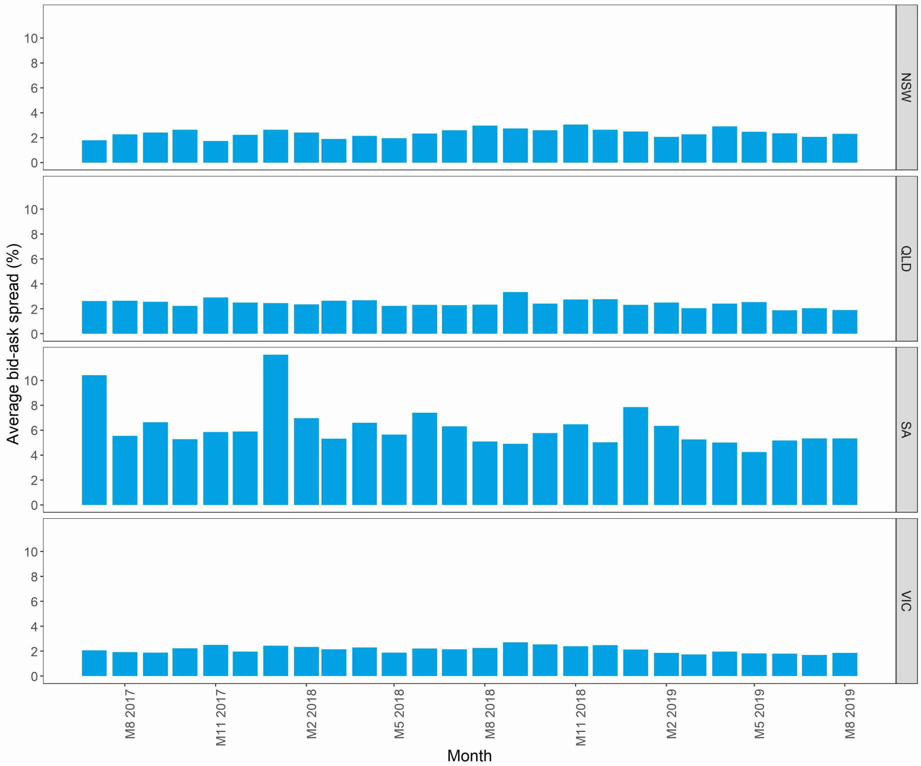


Source: ASX
Note: Chart shows 24 months prior to market making commencement and first two months turnover since commencement of market making scheme. M8 2019, refers to Month (August) and Year (2019) of trade.

4.3.5 Bid ask spreads

Average bid-ask spreads are broadly consistent with levels over the last two financial years. Given the first two months of the scheme has not seen a period of excessive volatility, during which bid ask spread specifications would be more likely to bind, it is perhaps to be expected there is no noticeable change, at this stage, in the average bid ask spread level.

Figure 4.7: Average bid ask spreads by month traded - baseload products



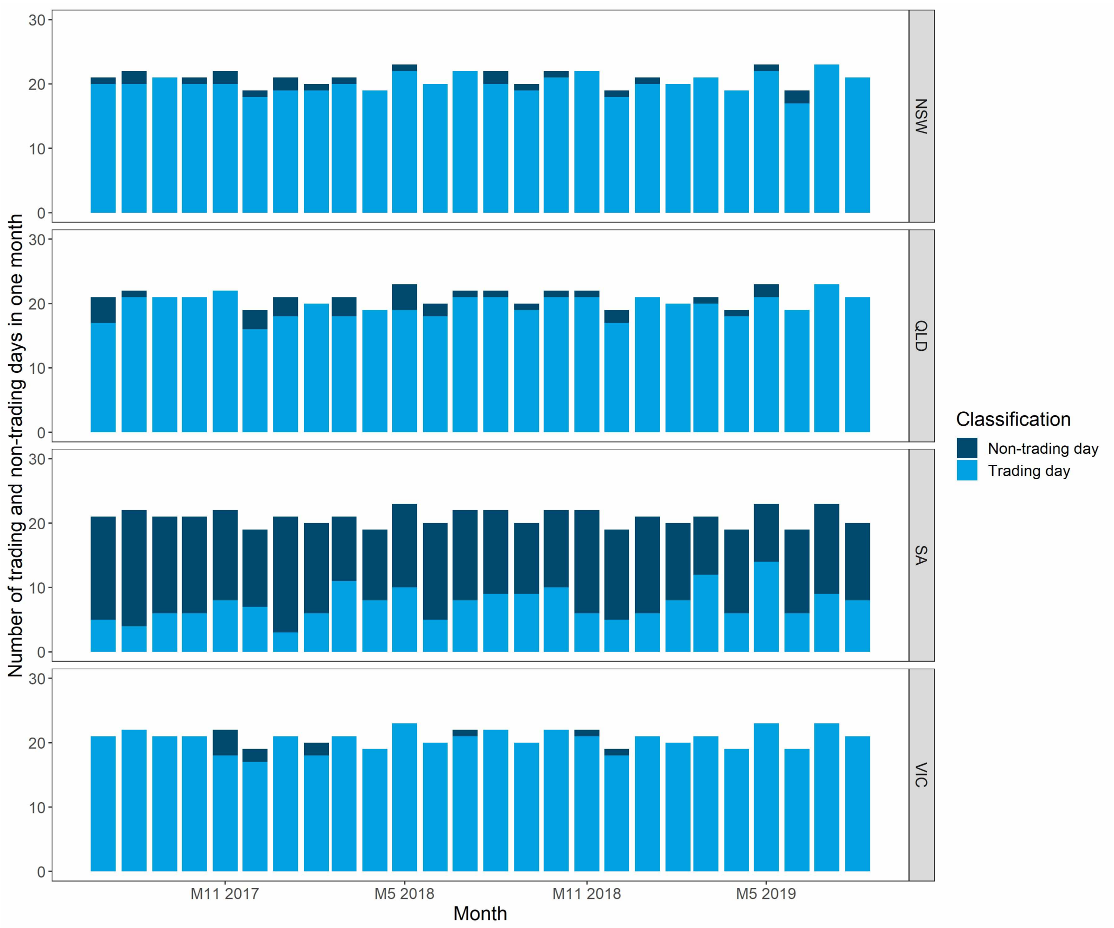
Source: ASX
Note: Chart shows 24 months prior to market making commencement and first two months turnover since commencement of market making scheme

4.3.6 Trading versus non-trading days

The number of trading days versus non trading days and the number of trades has also not changed significantly since 1 July. Market making can ensure prices are posted, but it cannot make participants trade more than they otherwise would. It is important, particularly in the context of the South Australia market, to observe this metric over time in relation to the greater price coverage provided under the market making scheme.

If price coverage improves over time, and the number of trades or the volume of trades does not improve, this may suggest that turnover levels in South Australia are lower due to the market structure in the region or that the price of hedges is not attractive to users compared to alternative risk management options (which may not be measured in current liquidity metrics).

Figure 4.8: ASX trading and non-trading days by month - all products

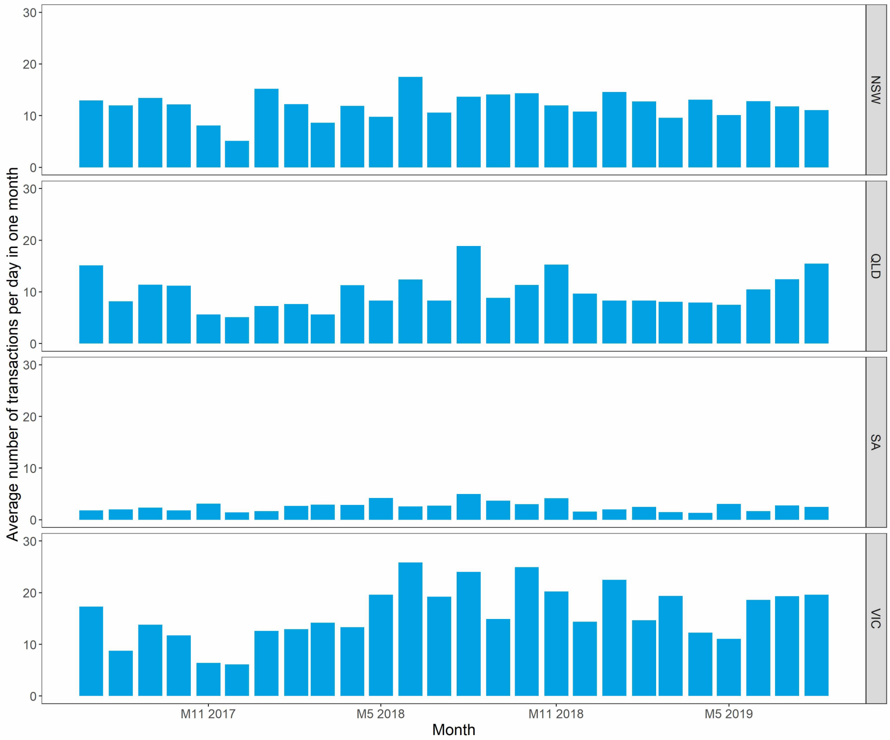


Source: ASX

Note: Chart shows 24 months prior to market making commencement and first two months turnover since commencement of market making scheme

4.3.7 Number of trades per day

Figure 4.9: ASX average number of transactions per day - all products



Source: ASX

Note: Chart shows 24 months prior to market making commencement and first two months turnover since commencement of market making scheme

4.3.8 Other observations from initial operation of the scheme

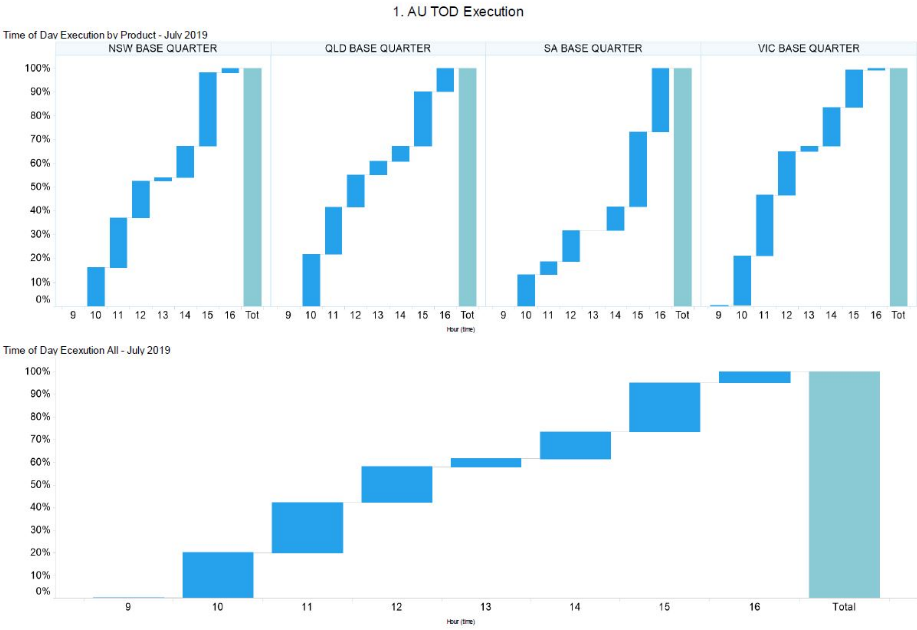
There have been concerns expressed about the risk that market makes bear and that stipulated windows for market making will concentrate liquidity into the market making windows, at the expense of other periods.

Initial data from the ASX is encouraging in relation to both these factors. Trading has not been exclusively concentrated in market making windows, and to date most trading in market maker products has been by other entities, within the price bands, made by the market maker.

A longer period of analysis will be required before conclusions can be made on these issues.

Figure 4.10 shows that trading in market maker products is occurring across all periods, including the market making periods.

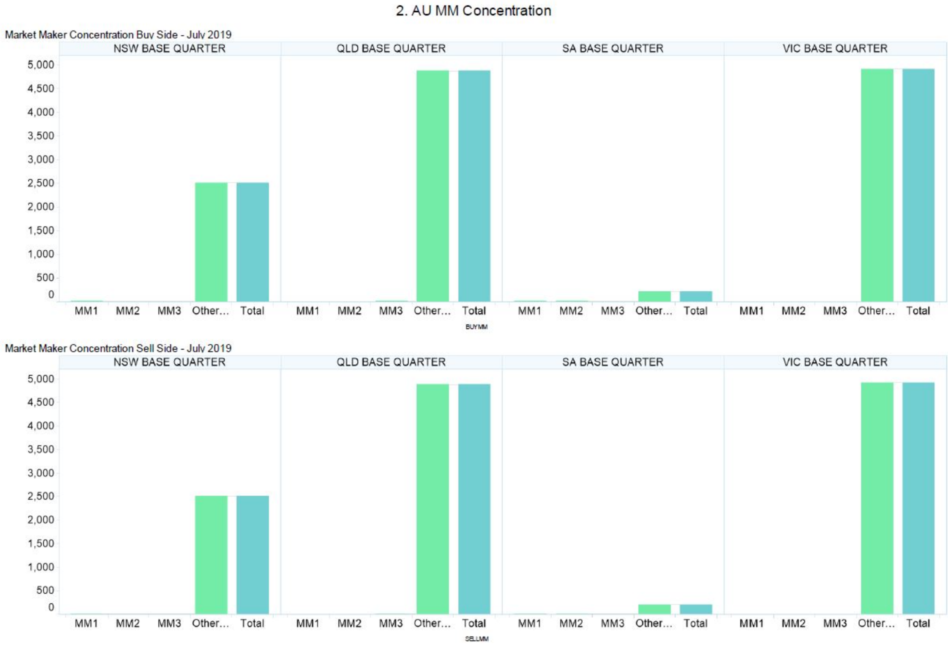
Figure 4.10: Time of day execution in market maker products - July 2019



Source: ASX
Note: Figure Note

Figure 4.11 shows that the majority of trade in market maker products is currently undertaken by entities 'Other' than market makers.

Figure 4.11: Concentration of trades with Market makers



Source: ASX
Note: 'Other' refers to trades completed by non market making participants. MM1 and MM2 refers to market makers.

4.3.9 Potential impacts on liquidity from the introduction of 5 minute cap products

In assessing liquidity and turnover in all products across the NEM in coming periods, consideration should be given to the transition to 5 minute cap products. Currently these products are not available on the ASX, although they are under development.

Consequently, liquidity of trade in cap products covering time periods from mid 2021 may be uncertain until these products are developed and available on the ASX platform for trade. This is now within the two year contracting window within which some retailers would be looking to trade in these products.

4.4 Improving contract market visibility

There are a range of alternative hedging products that participants use to manage risk. AFMA compiles and publishes its annual Electricity Derivatives Turnover Report.[18] The data is sourced from the ASX and a survey of industry participants, and covers both ASX and OTC transactions. This survey was put in place as an alternative to mandatory reporting on financial derivatives under Australia's G20 agreements after the global financial crisis.

18 For more information see: https://afma.com.au/data.

The survey results for 2017-18 show that approximately 95 per cent of turnover in the ASX and OTC markets is for swaps (84.7 per cent) and caps (9.9 per cent). The remaining five percent includes a series of products including day ahead swaptions, OTC caption calls, Asian options, captions and floors.[19] AFMA also report that the OTC market represents 25 per cent of the overall contracts market turnover, and 41.6 per cent of the OTC trades are conducted through brokers.

The AFMA report states that a range of products are not covered in its survey.[20] Participants listed the following alternative products:

- weather insurance and weather caps
- secondary settlement residue auctions (SRAs)
- wind and solar firming products
- load following hedges
- various weather contingent and plant-availability contingent derivatives with variable volume and payout characteristics.

These products are typically more bespoke than traditional swaps and caps. For example:

- a load following hedge is a product constructed by the seller from swaps and caps to meet the varying demand levels of a given purchaser
- weather insurance products, and wind and solar firming products, enable intermittent generators to offer firm contracts to customers despite varying generation.

These examples show how the market has adapted to provide risk management products required, given changes in generation technology and consequent changes in the types of contracts that can be offered.

Various industry participants have highlighted the importance of these products as the change in technology from traditional thermal to intermittent generation progresses, and storage options develop.

The Commission also notes that there are other well recognised risk management products that are not captured in ASX data or the AFMA survey.

- PPAs have been the most common form of contracting for intermittent wind and solar generators in recent years. These contracts vary in detail but commonly pay a fixed price for all the output from a generator, even though that volume may vary depending on weather conditions. There is no readily available data on the quantity or price of PPA contracting.
- Demand response contracts are another form of contract that can protect customers from high and volatile spot prices. Similar to PPAs, there is no readily available data on the quantity or price of demand response contracts.

19 ibid.

20 AFMA defined this as 'any other non-standard instruments employed that hedge forward electricity price risk that cannot beincluded in 'any other category' of the standard set of hedging instruments

The Commission will consider how best to gain transparency of all product types in order to have a complete picture of market liquidity. As noted, it will work with the AER, AFMA and industry on these issues.

4.5 Conclusion

The liquidity metrics described in the draft determination were not disputed by stakeholders in responses to that paper, although other metrics were proposed as being useful to gaining a broader understanding of liquidity. In working with the AER on enhancing its contract market monitoring powers, these additional metrics will be considered for the usefulness and data availability.

While there are some positive early signs in the first two months of market making - in particular in relation to the posting of prices, the availability of prices through most of the trading days, and pricing being available at the end of trading days - it is too early to draw conclusions on the affect of the ASX market making scheme on liquidity. It is also noted, that the level of participation in the market making scheme is lower than expected, except in South Australia. This may affect the benefits that can be expected, and will be monitored over time as part of the assessment of the effectiveness of a voluntary market making scheme.

In relation to the visibility of contract market transactions, there is no new information or evidence that changes the Commission's position from the draft determination. As such the Commission intends to work with the AER, AFMA and industry on addressing the identified information gaps.

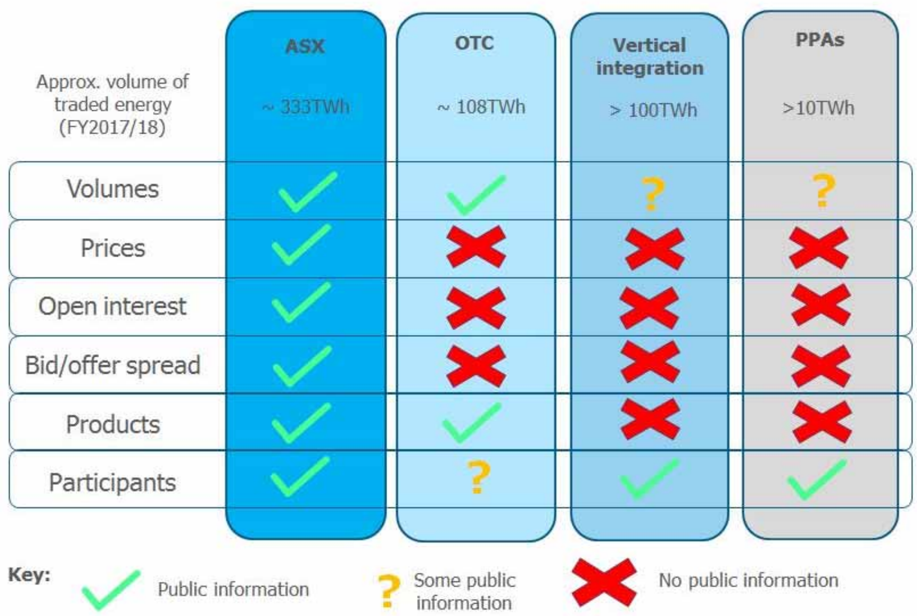
5 TRANSPARENCY

The draft determination identified information gaps in the contract market that undermine price discovery for market participants, and the assessment of market conduct and performance by regulators.

Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration).[21] The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as PPAs, demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

Figure 5.1 below maps the availability of information on contracting. It shows the market visibility of key contracting dimensions and estimated volumes against the type of contract.

Figure 5.1: Information map - NEM contract market



Source: ASX and OTC volumes are as per ASX and AFMA figures for 2017-18. PPA estimate based on wind and utility scale solar output at the end of 2017-18. Vertical Integration assessment is based on generation output from vertically integrated retailers. AEMC analysis.

The information gaps make price discovery for smaller market participants and prospective entrants difficult and may undermine confidence in the contracting market. The gaps also make it difficult for regulators to assess the conduct of market participants and market performance.

21 The nature of the internal agreements that vertically integrated participants use is not visible and may not be uniform. All such arrangements are referred to as contracts in the final determination.

The information gaps relate in particular to three sections of the market:

OTC contracts - represent approximately one third the volume of ASX trades, based on AFMA data. However, the AFMA data under-states the actual level of OTC contracting. For example, it does not include data on PPAs, demand response, weather derivatives or secondary SRA trading. There is also a lack of data on prices, so these trades do not directly assist existing or prospective market participants in price discovery.

Vertical integration — estimated volumes exceed 50 per cent of total market demand, although it is noted that these internally contracted volumes may be traded (multiple times) on the ASX and OTC to optimise a participant's contracting position. There is no market visibility on these contracts. This has led many smaller retailers and commercial and industrial (C&I) customers to question whether the prices they pay for contracts as an external party are reasonable compared to those available within vertically integrated firms. Uncertainty in this regard may undermine participants' confidence in the contract market and contribute to an unwillingness to buy or sell contracts, given market confidence is a key characteristic of liquid markets.

The ACCC did examine this issue using its information gathering powers as part of the REPI, and concluded that there was general equivalence between internal contracting and contracts offered to external parties. This 'point-in-time' finding may give participants improved confidence to enter into contracts. Notably the AEMC has not had access to the ACCC data.

PPAs — have been the most common form of contract for underwriting investment in renewable generation. While some contractual details may be reported, there is no systematic reporting of key contractual data.

This chapter describes how the Commission proposes to address the information gaps identified.

5.1 Improving price discovery

The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format.[22]The ESB has recently consulted with industry on this recommendation, and provided recommendations to the Energy Council.[23]It considered a preferable path is for the AEMC, AER and market participants to work with AFMA to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

The ESB supported its recommendations with reference to the following factors:

- the OTC market is a subset of market data and information on OTC trades is available to market participants via brokers
- there are challenges with providing the market with meaningful data given the bespoke nature of some OTC contracts

22 See ACCC, recommendation 6.

23 The ESB provided advice to the Senior Committee of Officials on 19 May 2019. The Energy Council had not responded before this final determination was finalised.

- the costs of an OTC repository may be significant.

These factors are discussed in the following sections.

5.1.1 OTC data and availability

The OTC data reported by AFMA under-states the level of bi-lateral contracting in the market. PPAs, demand response, all forms of weather derivatives, wind and solar firming products, secondary trading of SRAs, and load following hedges are not captured in the AFMA survey. In aggregate, these products are likely to comprise a material volume of contracts. This is particularly the case in South Australia, where the high penetration of intermittent renewable generation means these products may be more relevant and suited to participants' hedging requirements.

Some information on these products may be available to participants via brokers. The AFMA survey indicated that OTC products (excluding those identified above) represented 25 percent of 2017-18 contract market volumes, and 41.6 per cent of the OTC contracts were transacted via brokers. If it is considered that the contracts transacted by brokers are visible to the market and represent approximately 10 per cent of the total contracting market, there is still approximately 15 per cent of the market that is not visible. Given the gaps in the AFMA data, in particular in relation to PPAs, demand response and weather derivatives, the Commission considers the non-visible portion of the contract market may be materially larger than implied in the AFMA data.

It is also notable that the volume of contracting between the ASX and OTC varies over time and by jurisdiction. This means the visibility of contract market data will also vary. For example, in South Australia, OTC trading comprised over two-thirds of contract market activity in 2015-16 and 2016-17, although it can be materially lower in other years.

The Commission also looked at the availability of information from brokers. Participants can access broker services in two broad ways, they can:

- subscribe to a broker service, and receive daily updates on contract market prices that the broker has access to
- engage a broker for assistance with a specific transaction.

The Commission understands there are six to seven major brokers operating in the market, and subscription services cost between $20,000 and $30,000 per annum per broker. Small and infrequent traders will likely find these services too expensive, and will instead rely on advice on a per-transaction basis. Larger participants with more frequent trading activity may subscribe to a number of or all of the services.

A further consideration is that the types of contracts currently not captured by the AFMA survey are likely to be the contracts increasingly needed as technology continues to shift to intermittent renewable generation and customers have an increasing ability to invest behind the meter in generation and demand response technologies. In short, given current industry trends, contract data availability is likely to diminish rather than improve in the near term unless additional data capture mechanisms are developed.

It is also important to acknowledge that while the majority of OTC contracts are reasonably standard swap and cap contracts, other OTC contracts cover more bespoke products such as load following hedges. The Commission accepts that data on load following hedges would only be useful to the market if the market had information on the shape of the load being hedged. This is also the case for other non-standardised products. However, the difficulty of defining meaningful data for reporting should not exempt such data from consideration for reporting, and there is an opportunity for industry to provide leadership on such issues. It is noted that New Zealand has operated an OTC repository for a number of years (see Box 1,) and a number of participants at the AEMC industry workshop indicated they would like access to more data and were capable of analysing it themselves.

5.1.2 Addressing gaps in OTC data

The ESB recommendation on OTC visibility is for the AEMC, AER and market participants to work with AFMA to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period. Towards this goal, and reflecting the analysis undertaken in this rule change, the Commission has identified specific areas where improvement is required for the AFMA survey to provide adequate transparency of OTC trades. These include:

Price

There is no price information in the AFMA survey. It is the main item that needs to be addressed in order for OTC data to address the price discovery needs of the market. The Commission understands this will also be the most contentious item for AFMA and its members to address. AFMA will need to obtain the agreement of members to collect and publish pricing data, and it is concerned about potential legal consequences in publishing reference prices.

Coverage

There is scope to improve industry participation and product coverage. There were only fourteen participants in the 2017-18 AFMA survey, although they represented the majority of market generation and load, and the two main financial traders. The material product gaps in the survey have already been noted. In working with the AER, market participants and AFMA on improving the AFMA survey, threshold levels of participant and product coverage will need to be agreed.

Timeliness

The AFMA survey is conducted annually and released some months after the end of the financial year. This limits the usefulness of the data to industry, and means it would not be useful for price discovery even if it contained pricing data. The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery. The Commission is aware that more frequent reporting would necessitate a change from AFMA's current largely manual processes to an automated system. There would be costs in changing to an automated system, but the Commission questions the level of such costs. Market participants that trade regularly already capture trading data in their internal risk management systems. The costs of making this data, or some portion of this data, available for AFMA reporting seem unlikely to be material. For market participants that trade irregularly, the administrative costs of submitting data seem unlikely to be high.

There was no specific evidence put forward by stakeholders in response to the draft determination, to change the Commission's position on these issues.

Implementation and effectiveness

The Commission agrees with the ESB's recommendation to COAG Energy Council, in relation to the establishment of an OTC repository, that an enhanced AFMA survey is the most effective way to improve transparency in the OTC market, and that the effectiveness of the survey should be reviewed after a suitable period.

In support of this approach, it is important to agree some threshold issues in the near term. Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

Submissions from AFMA and industry highlighted some difficulties with improving the AFMA survey in relation to price discovery, coverage and timeliness. However, AFMA also indicated that there may be approaches to capturing data on trade in standardised products using broker data. AFMA and industry have indicated a desire to work with the Commission and the AER on the improvements to the survey set out in the draft determination.

In the event that an enhanced survey is unable to provide the threshold improvements in information that the Commission has identified, the Commission will concurrently work with the AER on alternative approaches to address information gaps in the OTC market. As an example, the Commission is examining the New Zealand hedge contract capture system and its success in achieving better reporting on contracts in New Zealand (see Box 1).

5.2 Improving regulatory assessment of market performance and conduct

The ACCC's REPI recommended an expansion of the AER's market monitoring function to include the contract market, and enhancing the AER's information gathering powers.[24]The ESB also examined this recommendation and supported the ACCC's position in its advice to the Energy Council. It recommended that the AEMC and AER work to draft law changes required to give effect to the AER's expanded role. The recommended law changes are to be provided to the Energy Council.

In the course of this rule change the Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, while noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. The specific changes are described below.

24 See ACCC, REPI, recommendation 41

5.2.1 Monitoring compliance with market making schemes

The AER will need to monitor whether participants in the ASX market making scheme adhere to the terms of the agreement, as an input into assessing the effectiveness of market making schemes in delivering liquidity.[25] If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants' non-adherence or the scheme design. The absence of clear performance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity. Therefore, compliance monitoring is critical.

Appendix F shows the key requirements of the ASX market making scheme compared to those of the MLO. The scheme designs converged in the last few months of development and are now closely aligned on most requirements. The key exception being that late in the process of the development of the ASX scheme, cap products were excluded from the market making agreement (although market makers have been seen to be making markets in caps despite there being no formal requirement in the market making agreement)[26]

The Commission understands that market makers in the ASX scheme are receiving a monthly compliance report from the ASX on whether they met the terms of the market making agreement. The key terms relate to whether the market maker offered the required product volumes during the required market making periods at the specified bid-ask spreads. If the market makers comply then they are eligible to receive the scheme incentive payments, including exchange fee rebates and a share of profit associated with the growth in trading that the market making scheme delivers.

The AER will not have automatic access to the ASX compliance report for market makers, nor does it have powers to compel the ASX to provide specified data. The AER will therefore have to source data directly from participants, or come to an alternative arrangement with participants and the ASX. Where possible, this should be monitored by the AER on an ongoing basis.

5.2.2 Monitoring and reporting on market liquidity

As part of its expanded role in monitoring and reporting on market liquidity, the Commission considers the AER should take account of the following factors:

- the performance of market makers in the ASX market making scheme and compliance with the MLO if triggered
- the liquidity factors examined in this rule change process, at least including; the availability of prices, the bid-ask spreads, the number of days with trading, the number of trades and trading volumes
- the structural characteristics of each jurisdiction.

Market makers' performance and industry participation in the scheme

25 As noted previously, this monitoring is to understand market liquidity. The AER does not have a formal role in monitoring participants' compliance with the ASX market making scheme

26 Cap are being sold up to Q2 2021. No cap products are available for Q3 and beyond as there are currently no 5 minute caps in the market. 5 minute settlement commences at the start of Q3 (1 July) 2021.

As noted, an understanding of whether adherence to the specifications of the ASX market making scheme has occurred is a pre-requisite to assessing whether the scheme design is sufficient and efficient. A record of participant adherence over time will be important in determining the success of the ASX and MLO schemes.

Liquidity factors to monitor

There are a wide range of liquidity metrics that could be monitored. However as described in chapter 4, the key metrics relate to:

- the availability of contracts, measured by the number of days market making services are available, the coverage of prices across market making products and trading periods, and the volume (and lot size) of contracts made available each day
- the price of contracts, as measured by the bid-ask spreads
- trading volumes and churn and the number of trades.

The availability of end of day pricing is a further metric that the Commission has sourced since the draft determination. This should also be added to the metric set for consideration.

Structural characteristics of each jurisdiction

The AER will need to account for structural differences in different jurisdictions in its ongoing assessment of, and reporting on, liquidity. In markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for the market making requirement to shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of the AER's monitoring task.

5.2.3 Reporting by large vertically integrated participants

In relation to the assessment of market performance and conduct in the wholesale and contract markets, it is noted that there is not a standard information base against which to assess whether large vertically integrated participants are exercising market power.

Despite the lack of regularly available data, a number of studies have proposed or examined structural solutions to the market, such as divestiture powers, ownership limits, underwriting of investment, and operational separation.

As a general principle regulatory mechanisms and responses should escalate in a manner that is proportionate to the risks and impact of particular market conduct. As large vertically integrated participants are corporations with significant market power and their conduct can have material and widespread impact on a market and consumers, it is reasonable that higher levels of regulatory scrutiny and stronger sanctions may be applied to such corporations.

An example of regulatory escalation is the differentiated requirements that can apply to corporations under the following:

- market and operating information requirements
- accounting separation

- operational separation
- ownership separation (divestiture).

The 2018 Prohibiting Energy Market Misconduct Bill includes divestiture powers, and the ACCC examined and rejected operational separation in the REPI. Nevertheless, recent detailed work has not been done on whether additional standardised information should be available to the regulatory agencies to assess the performance of the wholesale and contract markets, and the conduct of participants.

In the course of this rule change, the Commission has not attempted to examine the potential range of information gaps and additional information requirements that may be applied. At this time, it is therefore not recommending the implementation of an accounting separation regime or other more onerous alternatives.

However, the Commission does consider two specific areas are worth further consideration. The two specific areas for potential reporting by large vertically integrated participants are:

- information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting
- information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

These issues are commonly raised but there is poor data availability to enable assessment. The AEMC will examine these more closely in conjunction with the AER as part of developing the proposed law changes to enhance the AER's market monitoring and reporting function.

If this information were reported, it could be made available to regulatory agencies rather than market participants. It would therefore not be an aid to price discovery. The information would help regulatory assessments of market conduct and performance and may help to lessen industry concerns about the exercise of market power by larger participants. This may lessen the need for additional ad hoc inquiries into the industry. An additional indirect market benefit may also be an increase in participants’ confidence in market prices from large vertically integrated participants given the awareness of ongoing regulatory visibility of contract pricing and availability.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
Commission	See AEMC
MCE	Ministerial Council on Energy
MLO	Market Liquidity Obligation
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
REPI	Retail Electricity Pricing Inquiry
RRO	Retailer Reliability Obligation

A LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

A.1 Final rule determination

In accordance with s.102 of the NEL the Commission has made this final rule determination in relation to the rule proposed by the proponent.

The Commission has determined not make a final rule in relation to the rule proposed by the proponent.

The Commission's reasons for making this final determination are set out in section 3.5.

A.2 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the proposed rule
- the rule change request
- submissions received during first and second round consultation
- the Commission's analysis as to the ways in which the proposed rule will, or is likely to, contribute to the NEO
- the analysis conducted by NERA on the incremental cost-benefit analysis of different market making options.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.

A.3 Application in Northern Territory

From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL (referred to here as the NT Act).[27] The NT Act provides for an expanded definition of the national electricity system in the context of the application of the NEO to rules made in respect of the Northern Territory, as well as providing the Commission with the ability to make a differential rule that varies in its terms between the national electricity system and the Northern Territory's local electricity system.

The Commission has determined not to make a final rule and, consequently, has not made a differential rule in respect of the Northern Territory.

27 NT Act: National Electricity (Northern Territory) (National Uniform Legislation) Act 2015. Regulations: National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

B STAKEHOLDER COMMENTS ON KEY ASPECTS OF THE DRAFT DETERMINATION

This chapter summarises the key issues raised by stakeholders in response to the draft determination. These issues have been grouped into the following categories:

- the making of no draft rule and the determination that there is no incremental benefit from having additional market making arrangements at the current time
- measures in relation to observations of liquidity and the success of the market making scheme in improving liquidity in the contract market
- transparency measures in relation to OTC reporting and the AFMA survey
- transparency measures in relation to AER reporting of the contract market, including the potential for reporting of internal pricing and contract withholding.

B.1 No draft rule

The proponent's view

In its submission to the draft determination the proponent indicated disappointment with the determination of making no draft rule. The proponent indicated, however, an understanding of the rationale for the no rule outcome given the ASX voluntary scheme has been launched since the rule change request and the MLO now applies to several deemed generators.[28] The proponent reiterated that any scheme that does not place obligations only on physical participants will be the most sustainable over time. In this respect, the proponent hopes that the ASX market making scheme will continue to evolve and will better inform future discussion on the value of market making in the NEM.[29]

Stakeholder views

All respondents (other than the proponent) to the draft determination were supportive of no rule being made and as indicated above, the proponent indicated an understanding of the rationale for the determination.

Snowy Hydro commented that a compulsory obligation would increase the risk to gentailers which would then be passed through to customers. It would also risk inefficient use and mis-allocation of scarce resources thereby worsening consumer outcomes.[30]

A number of respondents reiterated that liquidity across the contract market is by and large acceptable, however certain markets, particularly South Australia, may have lower liquidity due to the underlying characteristics of that market. In addition, because of the nature of that market, participants are more likely to use risk management tools that do not show up in recognised liquidity metrics.

28 ENGIE submission to the draft determination p.1.

29 ENGIE submission to the draft determination p.1.

30 Snowy Hydro submission to the draft determination p.1.

Ergon Energy considered liquidity in Queensland to be acceptable and likely to increase with new renewable energy entering the market. Ergon maintain that this pipeline of renewable projects, together with the commencement of the RRO and associated MMO on 1 July 2019, should alleviate any need for additional market intervention.

The AEC acknowledged the lower level of liquidity in South Australia compared to other regions of the NEM but stated there is no clarity on what is an acceptable level of liquidity. Further, the AEC stated there is a range of risk management products that are equivalent to those assessed in liquidity metrics but that are not captured in any reporting of liquidity.[31] The AEC also supported the AEMC's discussion of structural factors and their impact on liquidity (see appendix d). The AEC expected that market signals will encourage the market to meet the demand for energy and related services. Infrastructure construction such as the Riverlink interconnector will also change the market dynamics, according to the AEC.

The AEC supported the conclusion made by NERA in the report for the draft determination that the net benefit of additional schemes for market making would be marginally detrimental due to the increase in regulatory and monitoring costs. As such, the AEC supports the conclusion that imposing additional market making rules in the NEM is unnecessary.[32]

Origin Energy supports the AEMC decision in favour of no rule, citing the introduction of the ASX scheme and the MLO and the fact that they are both aimed at addressing liquidity and contract availability concerns.[33]

The AER is supportive of the determination for no rule, stating that the proposed market making scheme would be unlikely to materially increase incentives for large, vertically integrated firms to offer contracts in the electricity contracts market. With the introduction of the ASX scheme and the RRO, the costs of an additional scheme would likely outweigh the benefits.[34]

AGL is supportive of the determination stating that the introduction of any further market making requirements would impose additional costs while providing no additional benefits. AGL in supporting the determination, drew attention to policy risks and regulatory uncertainties impacting the underlying energy markets. AGL commented that policy certainty would help to contribute to an increase in generation capacity that is capable of supporting firm contracts, and may also exert downward pressure on prices.[35]

AGL also questioned whether gas market reforms will assist with firm contracting. AGL considers that the day ahead auction of transportation capacity does not support firm contracting as it does not provide certainty ahead of time that fuel will be available to run a gas generator.[36]

31 AEC submission to the draft determination p.1.
32 AEC submission to the draft determination p.1.
33 Origin Energy submission to the draft determination p.1.
34 AER submission to the draft determination p.1.
35 AGL submission to the draft determination p.1.
36 AGL submission to the draft determination p.2.

The ASX indicated support for the draft determination. The ASX noted that the voluntary market making arrangement benefits from an alignment with the regulatory obligations under the MLO. This alignment, coupled with the potential for further market making arrangements being introduced by the market regulator, creates 'soft pressure' that the ASX says is an important factor in the success of the voluntary scheme.[37]

The ASX also pointed to a specific advantage of the voluntary scheme that it believes was not highlighted in the draft determination and that is the ability of the ASX scheme to evolve in response to changing market circumstances. The ASX states that this ability to evolve was recently evidenced in the New Zealand electricity market where the ASX operates a similar market making scheme to the one recently introduced in the NEM.[38] In the case of the New Zealand scheme, a period of extreme market volatility between October 2018 and February 2019 saw price making in the contract market break down due to significant price volatility. As a result, in March 2019, a revised scheme with updated obligations was developed. By April market making activity had recovered according to the ASX. In response to additional feedback from participants, additional amendments to the market making obligations were made by the ASX and agreed to by market makers.[39]

Energy Australia was supportive of the draft determination noting that it still considers an incentive driven market making mechanism to be superior to any compulsory mechanism and that successful market making needs to encourage other parties to participate in addition to physical participants. Any market making mechanism, according to Energy Australia, should not act in a way that forces additional risk on parties that are unwilling to take on that risk. Energy Australia maintained that financial intermediaries have the expertise to participate and the appetite to manage the associated risk.[40]

The SA Government Department of Energy and Mining notes in their submission that the results of the Commission's assessment of South Australia conditions show the state faces unique characteristics that contribute to a lack of liquidity compared to other regions and, as a result, market making alone may not solve the liquidity challenge. The Department notes reservations as to whether liquidity would be improved, until compliance with the scheme is tested.[41]

The SA Government also noted that while South Australia's structural characteristics are unique, it is conceivable that South Australia's experience, particularly relating to intermittent renewable generation, could be repeated in other NEM regions as they transition to low carbon economies. Monitoring the outcome of the new scheme in South Australia is a test case for the possible future experience of other regions.[42]

The SA Government concluded that the structural issues in South Australia are unlikely to disappear in the near term and therefore if arrangements in relation to both the RRO and the

37 ASX submission to the draft determination p.1.

38 ASX submission to the draft determination p.1.

39 ASX submission to the draft determination p.2.

40 Energy Australia submission to the draft determination p.2.

41 SA Government Department of Energy and Mining, p.1.

42 SA Government Department of Energy and Mining p.2.

ASX scheme do not improve liquidity, recommendations made by the ACCC in relation to mandatory market making in South Australia may need to be re-evaluated.[43]

Conclusion

The Commission considers that the wide support for making no final rule reflects a view that the net benefit of applying additional market making arrangements in the NEM is unlikely to be positive, supporting the analysis and conclusions presented in the draft determination and this determination.

Importantly in making the decision to make no final rule, the Commission does recognise liquidity is low in South Australia and has declined in other jurisdictions. In the event the ASX scheme does not perform as expected, then alternative schemes may be required.

In this regard, the Commission notes that support in submissions and engagement with the rule change process is not reflected in participation levels in the ASX market making scheme. Greater participation in the scheme will deliver greater benefits in terms of liquidity, both in the near term and in future under more challenging market circumstances than have been observed in the very brief period that the scheme has been in operation. The New Zealand experience illustrates the importance of collective participation in the scheme.

B.2 Ongoing measurement of liquidity and market making performance

The AER will need to monitor the adherence of participants to the terms of market making schemes, as an input into assessing the effectiveness of market making in delivering liquidity[44] If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants’ non-adherence or the scheme design or other factors related to the underlying physical conditions and investment in the market.

The absence of clear participant performance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity.

In monitoring and reporting on market liquidity, a number of factors should be accounted for including the level of adherence to the ASX market making scheme, the liquidity measures examined in this rule change process and the structural characteristics of each jurisdiction (see appendix d for a discussion of the structural factors impacting liquidity).

Proponent's view

The proponent did not express a view in its submission to the draft determination in relation to the ongoing monitoring of liquidity and the success of the voluntary market making scheme.

Stakeholder views

43 SA Government Department of Energy and Mining, p.2.

44 It is important to recognise that, unlike its role in relation to the MLO, the AER does not have a formal monitoring and compliance function associated with the operation of the ASX market making scheme. Its role in understanding participants' performance is to enable it to assess the success of the scheme in delivering liquidity.

In its submission, AGL highlighted that liquidity analysis should consider a wide range of metrics, not just the number of trades that occur. AGL referred to the size of bid offer spreads, the depth of bids and offers in the market, the time bids and offers are listed, the number of market participants, the availability of listed contracts and the regulatory risk appetite, impacted by regulatory changes, such as the five minute settlement rule change.[45] AGL maintain that future measures of liquidity should take into account the wide variety of risk management activities that participants undertake in preference to firm contracting. According to AGL this would help to explain the perception of lower liquidity in some states compared to others.[46] Such measures according to AGL should also include interregional interactions, for example trading in Victoria that takes place to manage risk in South Australia.

AGL also pointed out that the demand and spot price variability observed in some markets has an impact on the desire of participants to take up contracts, not just generator willingness to offer them. The load profile in SA, according to AGL, is peaky with relatively little baseload demand, thereby reducing the incentives for participants to seek contracts for baseload demand. The concentration of large end-use customers in South Australia is relatively low.[47]

The ASX considered that some degree of reporting of market making activity would be helpful and legitimate.[48]

In measuring liquidity and the performance of market making going forward, Energy Australia were keen to emphasise the role of financial intermediaries and the importance of monitoring metrics on participation by non-physical entities in the market in order to assess its performance. Energy Australia suggested the AEMC should investigate how intermediary participation changes and the drivers for this.[49]

Energy Australia recognised in its submission that the AER has a role in monitoring compliance with the MLO given that it is a compulsory market making scheme that sits within the remit of the AER's powers. However it considers the AER should have no role in enforcing compliance with the ASX scheme because it is a voluntary scheme.[50] Energy Australia stated that under the MLO arrangements, participants need to give permission to the AER to access confidential participant ASX trading data to monitor compliance for regions where the MLO has been triggered. It maintains that the AER will need to work closely with participants to receive additional confidential data for times when no MLO has been triggered or to access data in a region where the MLO is not occurring to allow ongoing monitoring of the effectiveness of the scheme.[51]

45 AGL submission to the draft determination p.2.
46 AGL submission to the draft determination p.2.
47 AGL submission to the draft determination p.2.
48 ASX submission to the draft determination p.2.
49 Energy Australia submission to the draft determination p.3.
50 Energy Australia submission to the draft determination p.4.
51 Energy Australia submission to the draft determination p.4.

Energy Australia also stated that it is concerned about the impact of future interconnection developments on contract availability. It encouraged the AEMC and the AER to monitor the impact of these developments on the contract market.

The SA Government strongly supported recommendations that the AER should monitor the performance of participants in the market making schemes and recommended that there should be a review of the impact of the schemes after two years. The SA Government considers that if the review shows that liquidity has not improved in South Australia, reconsideration of mandatory market making arrangements in South Australia could occur, consistent with the proposal by the ACCC.[52]

Conclusion

The Commission considers that ongoing measurement of the success of the ASX voluntary scheme in relation to participant performance in the scheme, liquidity metrics and the underlying characteristics of the NEM, are essential in ensuring the success of the voluntary ASX scheme in delivering improvements in liquidity.

Ongoing measurement of liquidity metrics and underlying market factors will inform any future decisions on the adequacy of liquidity and the need to adjust market making settings or requirements.

The Commission is working with the AER on the development of proposed changes to the NEL to broaden the AER's market monitoring and reporting functions and powers to capture the contracts market, and how these might relate to the ASX market making scheme.

B.3 Transparency measures in relation to OTC reporting and the AFMA survey

The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format. The ESB has recently consulted with industry on this recommendation and has provided recommendations to the COAG Energy Council. It considered a preferable path is for the AEMC, AER and AFMA to work with market participants to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

The Commission noted in the draft determination that in examining the AFMA survey, there were three areas of improvement needed in relation to price, timeliness and the coverage of the survey in relation to market participants and products not currently covered.

The Commission agreed with the ESB that the effectiveness of an improved AFMA survey should be reviewed after a suitable period, however, some threshold level of improvements should be agreed in the near term. These issues should include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. The Commission concluded in the draft determination that these threshold decisions should be made before the end of 2019.

52 SA Government Department of Energy and Mining, p.2.

Proponent's view

The proponent maintains that arguments around market transparency are often driven by parties who are not themselves market participants. The proponent considers that transparency improves efficiency where it improves decision-making by market participants.

In the proponent's view, creating formal obligations to enable conclusions by market observers may be problematic.[53]

Stakeholder views

Snowy Hydro suggested the Commission should continue to work with relevant participants to address gaps when improving the transparency of the OTC market. The AFMA survey, according to Snowy Hydro, provides a forum for industry participants to work with each other and government to improve its effectiveness and strengthen industry structures, meeting policy needs but without the need for onerous new regulations.[54] Snowy Hydro stated that the AFMA survey and the ASX voluntary market making scheme are clear demonstrations of the industry's commitment to support the future development of financial markets, so they continue to service the needs of the economy.[55]

Origin Energy commented that compliance requirements would be lower if market monitoring and reporting avoided duplication. Origin stated support for working with AFMA to enhance the electricity turnover report, while noting the ability to standardise OTC reporting is limited due to the bespoke nature of the contracts. The differing contractual terms and conditions in each agreement, according to Origin, has a direct bearing on the price which may not be reflected in a standardised report.[56]

AGL indicated support for an expanded AFMA survey to allow for a wider range of products, including pricing information and to be carried out monthly instead of annually, and to include a wider range of participants (currently 14 participants complete the survey). AGL, however, raised an issue with providing prices to AFMA, stating that providing prices may be a breach of contract to a third party, and so may need to be aggregated and weighted prior to being provided to AFMA.[57]

Energy Australia maintained that reporting obligations for OTC contracts should not focus only on the sell side, they need to apply to all parties including the demand side. It provided the example of a PPA where the drivers for selling the contract are likely to be different to the drivers for buying such a product. As such, Energy Australia maintained, both sides of the transaction need to be understood.[58] Energy Australia also stated that the contract market is not an area of expertise for regulators, and it is therefore concerned that incorrect conclusions may be drawn from contract data. As such, it sees benefits in using AFMA's skills to improve the AFMA survey.[59]

53 ENGIE submission to the draft determination p.2.
54 Snowy Hydro submission to the draft determination p.1.
55 Snowy Hydro submission to the draft determination p.1.
56 Origin Energy submission to the draft determination p.1.
57 AGL submission to the draft determination p.3.
58 Energy Australia submission to the draft determination p.1.

However, Energy Australia also noted in relation to the AFMA survey that it has limited coverage and is voluntary, but there is a need to ensure all participants are captured. It further stated that the risks of providing sensitive price data to a member based organisation need to be mitigated. It also questioned the need to provide monthly data and suggested that the provision of monthly data will create a significant additional burden on participants.[60] There is scope for the AFMA survey to be improved according to Energy Australia, but there will be challenges around delivering this to the AEMC's expectations including, coverage, price and timeliness.[61]

AFMA identified a number of problems with the survey improvements identified in the draft determination but then expressed support for working with the Commission to identify potential ways forward in relation to enhancing the survey. It agreed the AFMA survey is the preferable path to improved OTC reporting. However it also stated that its members are not convinced that information gaps in the current market are material. AFMA noted that it is looking to issue an updated survey for the 2018-19 financial year by the end of the current quarter.[62]

In relation to price discovery, AFMA stated that between 2001 and 2014 it provided regular price information on standard OTC electricity derivatives but this was discontinued following a review of the utility of the data. AFMA no longer provides price data and does not intend to do in the forseeable future, because it considers there are significant regulatory and compliance issues associated with collating the data, which would require specialist organisational capacity to provide.[63] Consequently, it maintains the current electricity derivative turnover survey will not be extended to include price data.

However, AFMA indicates that along with its members it is keen to work with the AEMC and AER to explore alternative solutions to improve price transparency in the market. To do this AFMA suggest a number of issues need to be addressed. The products to be covered, the information needed to enable price discovery and the sources of information would all need to be determined. AFMA considers brokers may be a better and more understandable source of price information for standardised products that are traded through brokers. More bespoke products, in AFMA's view, do not contribute useful content to the broader market price formation process. The price information could be meaningless or misleading in some circumstances.[64] AFMA considers that transactions in non-standard products are more likely to be traded directly between market participants, rather than through a broker, and hence price information would be less accessible and more likely to contain commercially sensitive information. Further, AFMA considers that a company will need to be selected to act as a data provider for the price information. There are a number of specialist providers that could do this but the costs of the service would depend on the range of products to be covered and the frequency of reporting desired.[65]

59 Energy Australia submission to the draft determination p.2.
60 Energy Australia submission to the draft determination p.4.
61 Energy Australia submission to the draft determination p.5.
62 AFMA submission to the draft determination p.2.
63 AFMA submission to the draft determination p.2.
64 AFMA submission to the draft determination p.2.

In relation to the coverage of products, AFMA stated that the current survey attempts to capture all electricity derivative trading that can be measured in terms of megawatt hours. In AFMA's view, many non-traditional products may not be measurable in simple megawatt hours, and hence to date have not been part of the accumulated data. In the 2017-2018 survey, AFMA added qualitative information on non-standard products. AFMA stated it is keen to work with the AEMC and AER to enhance the survey to provide more information on these products, notwithstanding the issues of aggregating information on products that cannot be measured in simple megawatt hour terms.[66]

In relation to the coverage of participants, AFMA state there are 14 participants in the survey including all the primary financial market participants in the OTC market. These participants report turnover with non-participants. The only trades not covered are trades between non-participants and other non-participants, meaning a very significant portion of the OTC market turnover is captured, although this is difficult to definitely prove.[67] AFMA welcomes suggestions from the AEMC and AER on how to add more participants but noted that all relevant AFMA members are contributing and the survey is voluntary.[68] AFMA also stated that it would be happy to look at a solution which might involve an alternative data administrator if necessary.

In relation to timeliness, AFMA agreed that for price discovery, more regular data would be useful. However it suggested that the solution for price discovery should be separately addressed outside of the AFMA turnover survey, and that this solution should be mindful of the need for regular price information. AFMA noted it is not certain of the benefits of more regular turnover data, as this does not aid in the price discovery objective. It also maintained that any change in the regularity of the electricity derivative turnover survey would need to consider the costs and burden placed on AFMA and its members.[69]

AFMA also noted the Commission's intent to agree certain threshold issues in the near term. It indicated agreement with this approach and the timetable of 2019 for these threshold decisions to be made. AFMA recommends a collaborative effort with its members, the AEMC and the AER towards a solution that benefits all parties.[70]

The SA Government Department of Energy and Mining notes that given their reservations about the ability of the voluntary scheme to improve liquidity, the Department strongly supports the Commission's recommendation in relation to information gaps in the wholesale contract market and the AER's monitoring functions.[71]

The SA Government indicated strong support for the proposed improvements to the AFMA survey. It stated that addressing information gaps in the market is a crucial tool to improving transparency and thereby liquidity. This work needs to be done as a priority and implemented

65 AFMA submission to the draft determination p.3.
66 AFMA submission to the draft determination p.3.
67 AFMA submission to the draft determination p.3.
68 AFMA submission to the draft determination p.4.
69 AFMA submission to the draft determination p.4.
70 AFMA submission to the draft determination p.4.
71 SA Government Department of Energy and Mining p.2.

as quickly as possible. The SA Government supported the Commission's recommendation that uncertainty over improvements to the survey should be addressed before the end of 2019 and if not, alternative methods including progressing further with the ACCC's recommended OTC repository should be considered.[72]

Conclusion

The Commission acknowledges the challenges the industry has identified in improving the AFMA survey, in particular in relation to the confidentiality of pricing data, the coverage of products, the standardisation of non-standard contracts and the potential administrative costs of reporting on a more regular basis. However it notes that New Zealand has operated a trade repository for a number of years, and that various solutions do seem possible, without adding materially to compliance costs. The Commission intends to undertake more detailed work with the AER, AFMA and industry to determine whether the AFMA survey can address the identified gaps.

Among other options, the Commission will address the AFMA suggestion that broker data could be used to inform the market about OTC trades and a third party agency could collect and report this data. The Commission's initial view is that while broker data may represent an improvement compared to existing arrangements, such data does not cover all OTC trading, nor would it assist in visibility of contract structures such as PPAs and demand response. As increasing intermittent generation enters the NEM, these contracts will become a more important part of the market, and understanding them will be increasingly important to understanding liquidity.

The Commission will concurrently work with the AER on alternative approaches in the event that the gaps in the AFMA survey cannot be adequately addressed.

B.4 Enhancing the AER contract market monitoring function

The draft determination raised the prospect of large vertically integrated market participants regularly reporting specific additional data to enable ongoing assessment of market conduct and performance. In the course of the rule change the Commission identified two specific areas for further consideration; information on internal pricing and contractual conditions compared to contracts to third party retailers or third party generators, and information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management.

This information would inform questions of fair dealing and withholding by large vertically integrated participants. These issues are commonly raised but there is poor data availability to enable assessment.

Proponent's view

The proponent maintains that the growing interest in internal transfer pricing and risk management threatens to further impair the ability of market participants to manage their businesses. The proponent considers that in the end, internal decisions should be left as

72 SA Government Department of Energy and Mining p.2.

matters for companies to manage independent of regulator intrusion. Retail tariff prices and wholesale contract prices on the other hand, are the prices faced by customers.[73]

The proponent goes on to state that the benefit of the ASX scheme is its voluntary nature and that caution should be exercised before the AER places additional reporting requirements on participants. In the proponent's view, compliance obligations across the NEM are already excessive and little attempt has been made by the AEMC or the AER to address this or quantify productivity improvements from reducing regulatory burdens.[74]

Stakeholder views

Origin stated that, any market monitoring should minimise duplication and the burden of compliance. The ACCC, according to Origin, is conducting wide-ranging monitoring into the supply of electricity, with the scope of the inquiry also covering contract markets. Origin is concerned that granting additional information gathering powers to the AER to monitor the contract market will result in duplication and increased regulatory burden, given the existing ACCC activity and the Australian Securities and Investments Commission’s role in overseeing derivatives contracts.[75]

Origin maintains that if the AER requires additional insights into the contracts market to effectively fulfil its obligation, it should first look to leverage the information gathered through the ACCC’s monitoring.[76] A streamlined approach to monitoring activity in the energy market, according to Origin, is crucial and will help to minimise the burden of compliance and provide greater clarity to participants. If the NEL is amended to give the AER additional information gathering powers to monitor contracts markets, it is not clear in Origin’s view, why this should continue to be a focus of the ACCC’s inquiry.[77]

AGL suggested that in developing the market monitoring role of the AER further in relation to the contracts market and additional information from vertically integrated companies, that overlaps with other reporting obligations and regulatory reviews are taken into account and any duplication avoided.[78] It referred to the ACCC seven year inquiry into electricity supply in the NEM, which includes an assessment of prices, profits and contract liquidity, which will run to 2025. AGL noted that while this is a temporary measure, AER monitoring would be an ongoing feature, and therefore it may be unnecessary to have two regulatory bodies assessing the same issues. The administrative burden on companies complying with information requests is significant according to AGL. It does not believe there is a persuasive case for both these processes being run at the same time.

In relation to the expansion of powers such that the AER might assess whether there is any ‘exercise of market power’, AGL noted that the ACCC is responsible for enforcing the Competition and Consumer Act (CCA), including the prohibition against misuse of market power. AGL also noted that the ACCC has significant powers to compel the production of

73 ENGIE submission to the draft determination p.2.
74 ENGIE submission to the draft determination p.2.
75 Origin Energy submission to the draft determination p.1.
76 Origin Energy submission to the draft determination p.1.
77 Origin Energy submission to the draft determination p.1.
78 AGL submission to the draft determination p.3.

documents and information in respect of any suspected breach of the provisions of the CCA. AGL also questioned the roles of the ACCC and the AER in monitoring energy markets, and whether it is appropriate or useful to have both entities considering the same issues simultaneously. Before there is agreement to expand the AER's role, AGL maintain this question should be considered and addressed.[79]

In relation to greater contract market monitoring powers for the AER, Energy Australia encouraged the AEMC and AER to work with industry to gain an understanding of what contract data would be most valuable and to determine how that data would be most efficiently and usefully reported. Energy Australia also considers that regulators should seek to minimise duplication of reporting and information requirements.[80]

Energy Australia noted that interpretation of the information in relation to internal transfers will be critical to the level of value this information will provide to regulators. Each market participant's contracting arrangements will be different depending on for example, risk appetites and hedging strategies which may impact the timing of trading activities for both generation and load. Energy Australia encourages regulators and the AEMC to continue to develop expertise in contract markets and understand the type of data they wish to prioritise and disseminate to maximise market outcomes for the consumer.[81]

The AER stated that while it has the necessary powers to monitor compliance with the RRO, it does not have comparable powers to monitor the contract market as part of the ASX market making scheme or similar schemes. The AER considers that expanding the scope of AER market monitoring to include the contract market, among other matters, is vital for it to be able to assess the effectiveness of competition in wholesale markets.[82]The AER notes that it looks forward to working closely with the AEMC to progress the transparency reforms.

The SA Government noted the high level of vertical integration in South Australia in supporting the Commission's recommendation that large vertically integrated participants report information to the AER relating to internal and external contract pricing and conditions and contracting volumes compared to generation availability and capacity.[83]

Conclusion

The Commission recognised the issues raised by stakeholders in response to the consultation paper and draft determination, and has taken these into account in this determination.

In relation to the potential duplication of reporting requirements, to different regulators, the Commission agrees these arrangements should be streamlined as much as possible. It will specifically consider this in working with the AER in developing proposals to enhance the AER's market monitoring functions, to include the contract market, and information gathering powers.

79 AGL submission to the draft determination p.3.
80 Energy Australia submission to the draft determination p.4.
81 Energy Australia submission to the draft determination p.5.
82 AER submission to the draft determination p.1.
83 SA Government Department of Energy and Mining p.2.

C CONTRACTING FOR GAS TO PROVIDE FUTURES CONTRACTS IN SOUTH AUSTRALIA

The MLO requires specific generators to make contracts available for retailers to buy in order to fulfil the RRO. The South Australian government also progressed a modification to the RRO framework under the National Electricity Law (NEL) and Rules, to provide the South Australian Energy Minister with the ability to make a T-3 Reliability Instrument under the RRO and, in turn, trigger the MLO process in that state. This became operational on 1 July 2019.

The ASX market making scheme will also require generators to make additional contracts available in South Australia.

Gas powered generation is the dominant form of firm generation in South Australia, and so the availability and price of gas and gas transport is a key determinant of whether contracts can be made available and at what price.

Gas trading in South Australia occurs under the contract carriage model. Generators must have gas transportation agreements with the pipeline operator in place to transport gas. The terms for access are negotiated and can be firm or non-firm (interruptible). Market makers require firm access to capacity in order to offer firm contracts.

Gas supply and transport are typically contracted long term. Gas transport provides for the delivery of a maximum daily quantity (MDQ) between two points on a pipeline. Gas supply agreements have provisions for an annual quantity of gas to be delivered, and also a maximum daily quantity. Long term agreements are bilaterally negotiated off market and there is little publicly available information on the terms of these agreements.

Gas supply can be purchased shorter term through the short term traded markets (STTMs). The STTM is a day ahead gas balancing market with hubs at Sydney, Adelaide and Brisbane. A market clearing engine uses bids, offers, and forecasts submitted by participants, along with physical constraints to determine gas schedules. To participate in the STTM, participants must hold rights to transport gas along the relevant pipeline(s). There is no forward price certainty for gas bought through the STTM, and so this is unlikely to help market makers offer capacity in the future at a pre-determined cost.

Gas transport capacity can also be purchased on a short-term basis. The ACCC noted in their recent 2018 Gas Inquiry Interim report that an increasing portion of new GTAs have terms of one year or less. Capacity can be purchased either directly from the pipeline owner ("primary trade") or from the holder of current capacity rights ("secondary trade"). AEMO publishes an uncontracted capacity outlook for each pipeline on the gas bulletin board, providing gas buyers and shippers with information on spare pipeline capacity up to 12 months ahead. One of the ACCC and GMRG joint recommendations in their December 2018 report on *measures to improve the transparency of the gas market* is to require AEMO to extend the outlook to 36 months. Secondary trade agreements for gas transport, are often on an 'as available' or 'interruptible' basis which have a lower scheduling priority to a firm service and therefore may not be appropriate for market makers looking to offer firm contracts.

Even though short term capacity may not always be firm, short term trading of gas supply and transport capacity can be used to manage longer term contracts and allow market makers to optimise or adapt their position by buying or selling capacity at the margin.

Trading of short term capacity has become easier through the capacity trading reforms introduced in the gas market in March 2019. Some pipelines had been fully contracted with little or no secondary capacity trading. Two components of the reforms, the Day-ahead Auction (DAA) of contracted but un-nominated capacity and the AEMO operated Capacity Trading Platform (CTP) may help to facilitate greater access to capacity and greater visibility over price and other key terms. The reforms provide pipelines with an incentive to trade spare capacity on the Capacity Trading Platform (CTP). Any contracted but un-nominated capacity that is not traded before the cut-off time is offered to other participants through the Day-ahead Auction (DAA).

While the day ahead auction may not be suitable for market makers, given the capacity auctioned is both non-firm and only available for the day ahead, it may increase short term capacity offered on the capacity trading platform in the future given owners of pipeline capacity do not derive a benefit from day ahead auction revenues, but would receive revenue from capacity offered on the capacity trading platform.

There are other short term options available to generators looking to meet market making commitments, but they are expensive. Linepack, gas that is stored in pipelines, can be purchased at short notice, but generally a premium is paid to gain access to this gas. Alternatively, some gas generators can use alternative fuels during periods where gas is unavailable or prohibitively expensive. There are also short-term forward products available on the Gas Supply Hubs (including at Moomba) however the fixed cost nature of these products are not well suited to the variable nature of peaking generation demand.

While the situation is likely to improve given the capacity trading reforms recently enacted, contracting for gas to meet market making commitments in South Australia is likely to remain challenging and expensive, particularly for peaking gas generators looking to meet market making commitments. The firmer the gas supply required and the greater the variability of gas load, the higher the overall cost of delivered gas.

Even when gas and transport is available to meet the requirements of peaking generators, the economics of providing firm hedges through gas generation are likely to result in high priced contracts that may attract limited demand.

D STRUCTURAL CONDITIONS IMPACT LIQUIDITY

This appendix describes the structural market conditions that impact on liquidity in the NEM, particularly in South Australia. It also examines developments that may impact on the South Australian market structure and liquidity in the near future.

In general, liquidity is influenced by the ability and willingness of participants to offer and buy contracts on the supply and demand sides. These are inter-related factors:

- the ability is driven by factors such as the quantity and characteristics of generation, the level of vertical and horizontal integration, the level and characteristics of demand, and the degree of interconnection with other markets
- the willingness is driven by price and volatility.

The supply of firm generation, the underlying spot price volatility, and the levels of vertical integration, demand and interconnection distinguish South Australia from other jurisdictions. In combination, the observed ability and willingness of participants to offer or buy contracts in South Australia is different to other regions. The result is lower levels of contract market liquidity observed over the long term.

This appendix explores these factors and why understanding the influence of structural factors on liquidity is critical when considering market making arrangements. There is potential for the market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker in markets where structural factors reduce liquidity but market making requirements are high. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of the regulatory assessment.

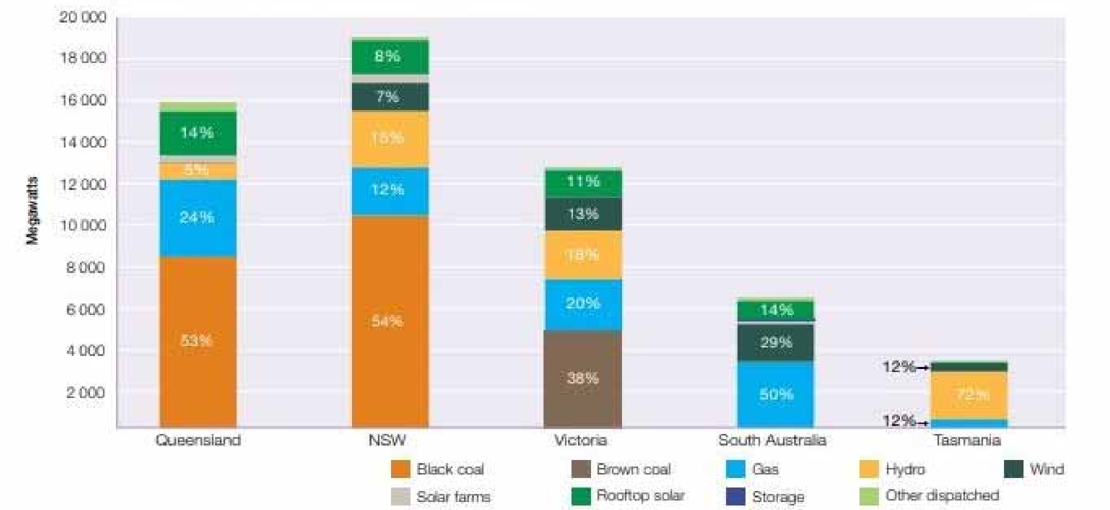
The supply of firm generation in South Australia

'Firm' generation is generation that is dispatchable and has a high ability to be able to defend (traditional) contracts for a particular delivery period. Examples of firm generation include gas and coal-powered generators, hydro-electric generators and battery storage systems. However, the contracts written by 'firm' generation may vary significantly between technology types.

The proportion of firm generation available

South Australia has less firm generation available than other jurisdictions to meet changes in demand and provide firm hedges. Renewable generation is a large proportion of South Australia's total generating capacity compared to other states, as seen in Figure D.1. South Australia's higher penetration of renewable generation reduces the available quantity of firm contracts because renewable generators cannot offer firm supply without associated storage or firming infrastructure.

Figure D.1: Share of firm and non firm generation in South Australia and the NEM



Source: AER, State of the market report 2018, figure 2.6
Note: Generation capacity at 1 July 2018. Rooftop solar output estimates derived from CER data on installed capacity and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage only includes battery storage.

Surplus generation by region

The quantity of firm hedges available in a region is also influenced by the quantity of firm generation that is surplus compared to demand.

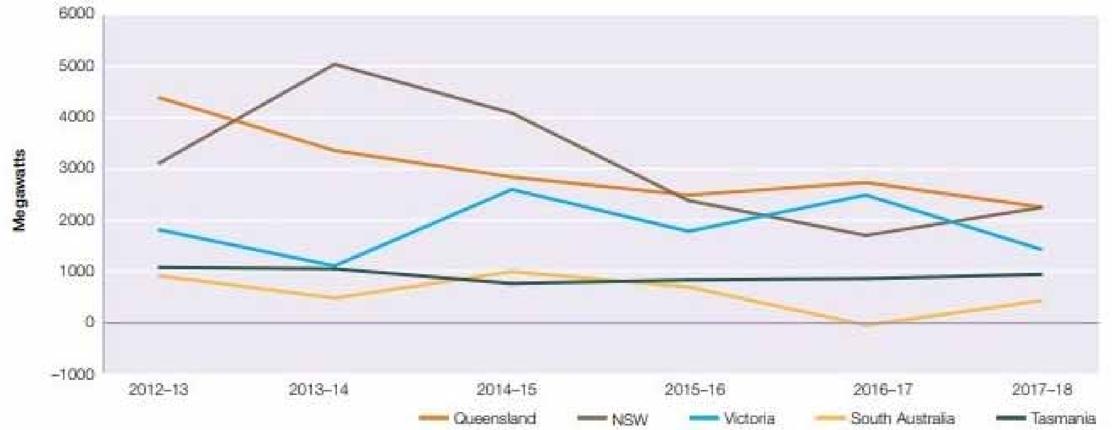
South Australia requires imports during peak demand periods if intermittent generation is not generating. This is because firm generation in South Australia (comprising gas, diesel and batteries) made up 2,908 MW out of a total of 4,408 MW registered available summer scheduled and semi scheduled capacity in 2017-18.[84] This level of firm generation is below both the instances of the maximum demand observed in FY14 and FY 17 as well as AEMO's POE10 maximum demand forecasts, which are in excess of 3,000 MW.[85]

In Figure D.2, generation in South Australia includes wind and solar summer capacity de-rated based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand. However, even when de-rated, this capacity is not suited to offering firm hedges. Therefore, South Australia is reliant on interconnection and intermittent generation to meet its maximum demand, which in turn means there is a lack of contract availability for peak demand periods.

84 AEMO, *Generation information page -- South Australia: Summer Scheduled Capacities tab*, 10 May 2019.

85 AEMO, *South Australian Electricity Report — figure 5,* November 2018.

Figure D.2: Surplus generation capacity by region



Source: AER, State of the market report 2018, figure 2.22.

Note: Maximum demand in financial year minus summer capacity (nameplate capacity for non-scheduled plant) at 31 January in each region. Summer capacity for 2016-17 in Victoria includes Hazelwood, with closure of the plant reflected in 2017-18 data. Wind and solar summer capacity is de-rated based on AEMO's 'firm' contribution estimates to account for generation is likely to be operational during periods of maximum demand.

The role of gas generation in South Australia

Gas is expensive relative to other fuels and the fixed costs associated with gas transport are high for generators operating intermittently or for limited periods. The costs and risks associated with obtaining a supply of fuel for gas generators negatively influences the quantity and cost of hedge contracts available in the market compared to other generation technologies.

In 2017-18 gas fired generation represented 58 per cent of total available summer generation capacity in South Australia, and 87 per cent of firm capacity.[86] A standalone generator contracting for gas transport in South Australia must recover a fixed gas transport cost from the electricity spot market that they are only likely to operate in for short periods. The high cost of operating gas fired generation in South Australia has been cited as a reason participants are not buying contracts and a cause for some operators to mothball generation units for a time.[87]

Participants' willingness to purchase contracts decreases as the price increases, and their incentive to explore other options (such as behind the meter options or vertical integration) increases.

86 AEMO, *Generation information page -- South Australia: Summer Scheduled Capacities* and *Existing S & SS Generation* tabs, 10 May 2019. Note: firm capacity does not include firm wind or solar capacity as stated by AEMO.

87 https://www.originenergy.com.au/about/investors-media/media-centre/origin-works-with-engie-to-help-boost-energy-security-in-south-australia.html

Figure D.3: Gas fired generation as a portion of South Australian firm and total capacity

Source: AEMO data, AEMC analysis.
Note: Firm capacity shown excludes de-rated wind capacity.

Reforms recently introduced in the gas market in relation to better access to pipeline capacity should help to reduce transport costs and improve the liquidity of these contracts over time. Nevertheless, the liquidity of transport and commodity gas contracts is an important consideration in assessing the performance of any market making arrangement, particularly in relation to South Australia.

The challenges of contracting gas and gas transport for the supply of firm hedges through gas fired generation is covered in more detail in appendix c.

Vertical integration

Vertical (and horizontal) integration can be rational and efficiency enhancing responses to market conditions. The operational and capital risks of operating across an integrated business may be lower than operating separate businesses. While low liquidity is often attributed to vertical integration, vertical integration can be a response to underlying market conditions which make forward contracting difficult rather than being the cause of low liquidity.

The ACCC's REPI report concluded that in certain regions of the NEM, particularly South Australia, the level of liquidity and the advantages enjoyed by vertically integrated retailers makes it difficult for new entrants and smaller retailers to compete.[88] New entrants cannot win significant market share without securing additional wholesale supply from competitors. There has been an observable reduction in the quantity of contracts available to the market where higher levels of vertical and horizontal integration exist.[89]

88 ACCC, *REPI Final report p.ix*.
89 ACCC, *REPI p.128*.

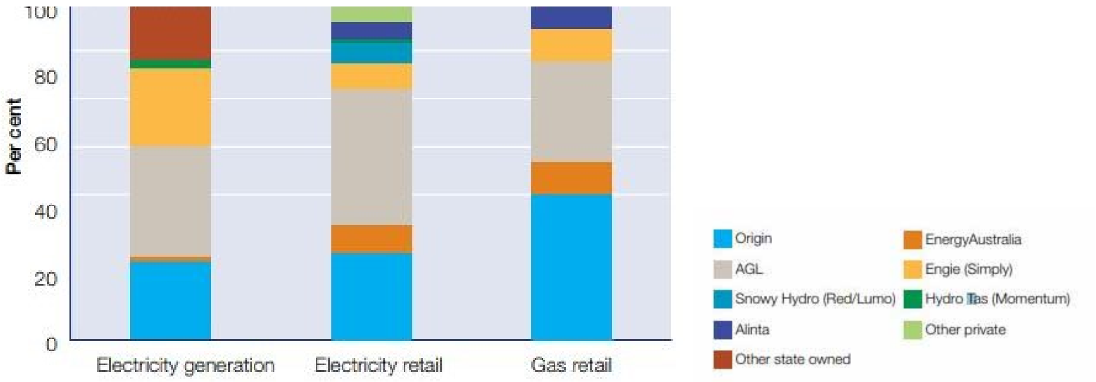
Irrespective of whether vertical integration is the cause or effect of low liquidity, the competitive effects of low liquidity need to be understood and potentially managed. Structural approaches such as divestiture requirements, ownership limits, or compulsory market making provide one set of options. Improved information is an alternative path (see chapter 5 on Transparency).

Of the 2,908 MW of firm generation capacity in South Australia:

- 95 per cent is owned/operated by vertically integrated participants. Only five per cent (130 MW from the Hornsdale and ESCRI batteries) is owned by other participants.
- all firm gas generation capacity is owned or contracted to vertically integrated participants.

Figure D.4 below shows South Australia's high levels of vertical integration in its electricity generation, electricity retail and gas retail sectors.

Figure D.4: Vertical integration in South Australia



Source: AER, State of the market 2018.
Note: This graph shows all generation market share for each business, not firm generation.

Vertical integration reduces standalone participant's ability to contract. This is because vertical integration reduces contract volumes, and hence market liquidity, compared to a market with the same generation capacity without vertical integration.

Demand and spot price volatility in South Australia

Compared to other jurisdictions, South Australia has low levels of demand, with approximately 12TWh of the 196TWh in the NEM in 2017-18.[90] It also has high rooftop solar penetration and a high proportion of installed wind capacity. These factors mean both the demand and supply profiles can change rapidly based on weather conditions.

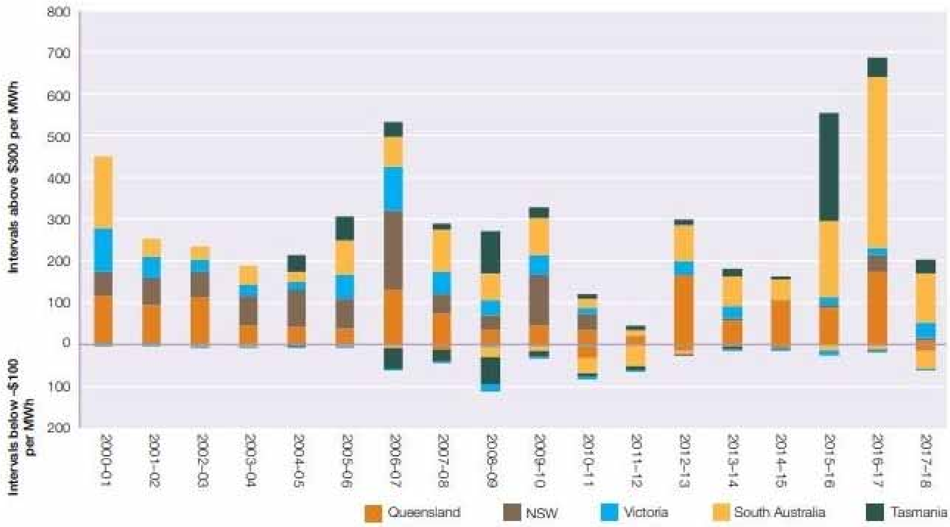
Demand changes and limited firm generation to meet supply can result in highly volatile wholesale spot prices. The interconnection capacity available from Victoria may offset this

90 AEMO, *South Australian Electricity Report*, November 2018, p.18 and AEMO, *The NEM fact sheet*, p. 2.

volatility to an extent, depending on whether there are interconnection constraints in operation.

Figure D.5 below illustrates that South Australian market has consistently experienced more price intervals above $300/MWh and below -$100/MWh than other jurisdictions.

Figure D.5: Intervals in the NEM with prices greater than $300/MWh and below -$100/MWh



Source: AER, State of the market report 2018, figure 2.30.
Note: Total number of intervals where spot prices exceeded $300 per MWh or fell below -$100 MWh.

Spot price volatility has a bearing on the willingness of generators to offer firm hedges and the price of those hedges. Generators may be less willing to contract when volatility is high, or they may be unwilling to provide hedges (for substantive capacity), without high premiums. Buyers may then be unwilling to pay those high premiums.

Customers who are faced with high prices have greater incentives to look for alternative lower cost solutions. Alternative products such as interregional hedging, SRAs, weather insurance or demand response, may be increasingly more economic than contracting for firm hedges.

How are these structural factors likely to change in the future

The structural factors highlighted are all more prominent in South Australia than in other states. The proportion of overall energy that comes from renewable energy, the small size of the market, the limited amount of firm generation, the reliance on gas to provide firm generation, the degree of vertical integration in the market (that may in part be linked to these factors) are all relatively pronounced in South Australia.

The question looking forward is the degree to which these factors might be expected to change. Reforms in the gas market may see reductions in the cost of firm pipeline capacity. Renewable generation as a portion of total energy is likely to increase through continued rooftop solar development and further wind and solar project development. Interconnection is set to increase through the development of the Riverlink interconnector, but this may have a bearing on the continued operation of some firm generation capacity in South Australia.

New battery developments in South Australia, both at a utility level and at a disaggregated level, may provide increased firm capacity. The development of demand response may also have a bearing on the availability of firm hedges. Some new thermal generation capacity is planned. However, in the medium term, the forecast supply-demand balance of firm generation in South Australia appears unlikely to change significantly. As a consequence, the impact of market making on South Australian contract market liquidity needs to be monitored and understood in that structural context.

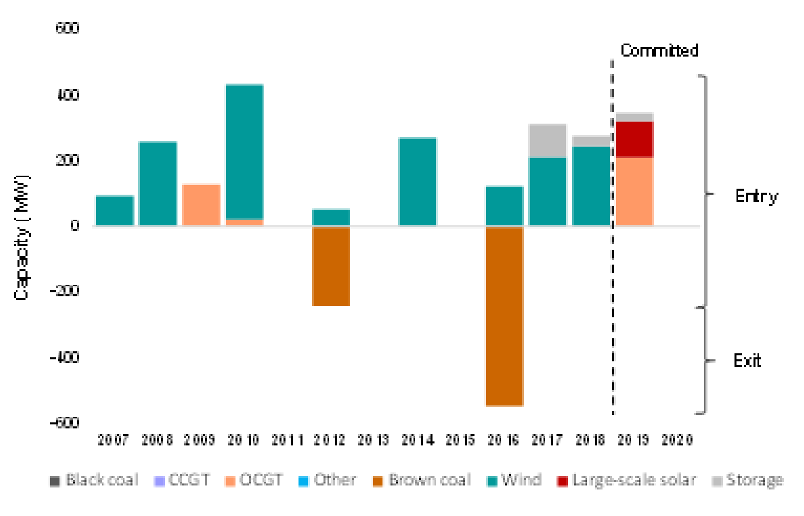
The following sections discuss new developments that may affect liquidity in South Australia.

Generation developments in South Australia

Current registered summer scheduled and semi-scheduled generation capacity in South Australia is 4,408MW.[91] 2,908MW of this is firm generation (gas, diesel, battery storage) with 1,500MW being renewable generation (solar and wind, excluding rooftop PV).

This reflects thermal generation retirements and renewable generation investment in recent years, as shown in Figure D.6 below.

Figure D.6: Entry-exit of generation in South Australia (2007 to 2020)



Source: AEMO data, AEMC analysis.

In terms of firm capacity, two large firm brown coal generators closed in recent years. Playford B (240MW) was mothballed in 2012 before closing in May 2016 with Northern power station (546MW).[92] The retirement of Northern was attributed to the high cost of operating

91 AEMO, *Generation information Page – SA*, 21 January 2019 dataset, viewed on 21 May 2019, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

92 AEMO, *Generation information Page – SA*, 18 November 2016 dataset, viewed on 21 May 2019.

with a brown coal fuel source and meant it had to operate in periods where prices were below operating cost for long periods due to the high penetration of renewables.[93]

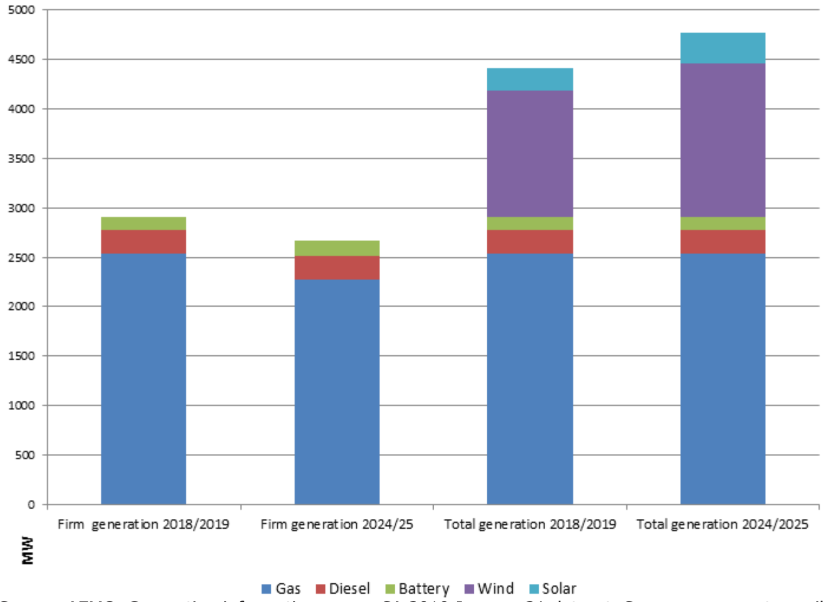
The gas fired Pelican Point generator (478MW) operated at half its installed capacity between 2015 and 2017.[94] ENGIE cited unfavourable market conditions including higher fuel costs and an increased market share of renewable generation explaining its original decision to mothball one generation unit. The second unit returned to full operation in July 2017 on completion of a gas deal with Origin Energy that is reported to run from 1 July 2017 to 30 June 2020.[95]

In terms of renewable generation capacity, 958MW of new wind and large scale solar generation capacity has been installed in South Australia since 2014.[96] A growing amount of battery storage has been installed with 130MW already in operation and a further 25MW due to be connected in 2019.

Planned developments

Over the medium term (see Figure D.7 below), the overall level of firm capacity is expected to fall slightly by 2024-25 and the overall level of renewable generation to increase.[97]

Figure D.7: Firm & aggregate summer capacity in South Australia (2018-19 to 2024-25)



Source: AEMO, Generation information page - SA 2019 January 21 dataset, Summer aggregate available scheduled and semi-scheduled generation tab.

93 Australian Broadcasting Corporation, *Port Augusta's coal-fired power station closes in South Australia*, 10 May 2016.

94 AEMO, *Generation information Page – SA*, 18 November 2016 dataset, viewed on 21 May 2019.

95 Origin Energy Ltd, *Origin works with ENGIE to help boost energy security in South Australia*, press release, 29 March 2017.

96 AEMO, *Generation information Page – SA*, 28 February 2014 and 21 January 2019 datasets, viewed on 21 May 2019.

97 AEMO, *Generation information Page – SA*, 21 January 2019 dataset, viewed on 21 May 2019.

The forecast above includes:

- a reduction in firm capacity driven by the retirement of Torrens Island power station A (TIPS A)[98] and the building of the Barker Inlet (210MW) power station by AGL, providing a net reduction in capacity of 27MW.[99]
- additional battery storage to be added with Lake Bonney Battery Energy storage (25MW).[100]
- additional renewable capacity to be added through committed projects including Lincoln Gap (126MW) and Willogoleche (119MW) wind farms and Bungala Two (110MW) solar farm.[101]
- the SA Government's Grid Scale Storage fund and Home Battery Scheme will also have a bearing on the supply-demand balance for firm hedges in South Australia in the longer term.[102]

Therefore, in the foreseeable term, firm generation in South Australia is expected to remain relatively unchanged. There is no apparent structural change thatThe South Australian government also progressed a modification to the RRO framework under the National Electricity Law (NEL) and Rules, to provide the South Australian Energy Minister with the ability to make a T-3 Reliability Instrument under the RRO and, in turn, trigger the MLO process in that state. This also became operational on 1 July 2019. would signal a material difference in the volume of firm contracts that could be offered in the near future.

The Integrated System Plan

The Integrated System Plan (ISP) was published by AEMO in July 2018. It forecasts the required transmission investments in the NEM over the next 20 years to provide consumers with safe, secure, reliable electricity at least cost across a range of plausible scenarios for the future.[103]

The ISP identified a range of network upgrades to be completed by the mid 2020s, including:

- the RiverLink interconnector between New South Wales and South Australia (750MW) is expected to be operational by 2024[104]
- 100MW increased interconnection between Victoria and South Australia on the Heywood interconnector by 2025 is also being considered.[105]

98 Two units (240MW) will be mothballed after winter 2019, one unit (120MW) after winter 2020 and the final unit (120MW) after winter 2021.

99 AEMO, *Generation information page - SA*, 21 January 2019 dataset, viewed on 21 May 2019.

100 ibid.

101 ibid.

102 See: http://www.energymining.sa.gov.au/energy_implementation/grid_scale_storage_fund.

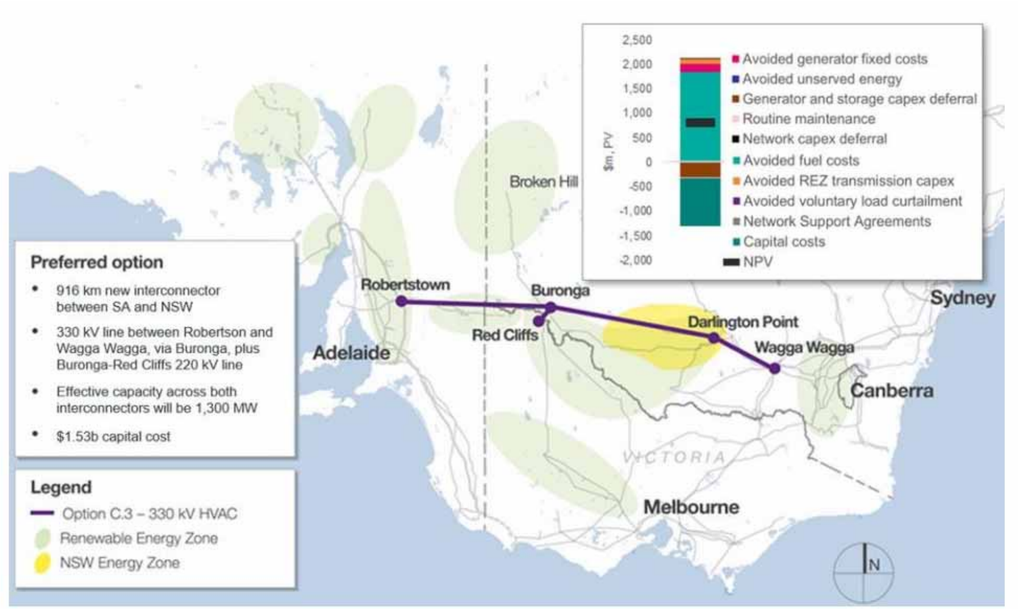
103 AEMO, *Integrated System Plan*, June 2018, p.3.

104 Dan van Holst Pellekaan MP, MOU on electricity interconnector, 19 December 2018. Visit at: https://premier.sa.gov.au/news/mou-on-electricity-interconnector

105 AEMO, *Integrated System Plan,* June 2018, p. 9.

These upgrades would allow renewable and base load generation in other NEM regions to be imported to South Australia, reducing costs for South Australian customers through fuel savings from reduced demand for gas powered generation (GPG).[106]

Figure D.8: Preferred option for the route of the NSW-SA interconnector



Source: Electranet, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, 13 February 2019

The expected impact of RiverLink on liquidity in South Australia

The relationship between the introduction of RiverLink, the retirement of firm generation, and impacts on liquidity, are not clear or agreed. The positions that have been put forward are:

- AEMO has forecast that RiverLink is likely to lead to lower overall utilisation of gas fired generation in South Australia and may therefore promote early retirement of firm generators.[107]
- Conversely, RiverLink may deliver additional firm generation from NSW to South Australia. Snowy Hydro has stated that the removal of interconnector congestion will allow it to offer more firming capacity in South Australia.[108]
- An investor in new renewable generation in South Australia submitted to Electranet that the interconnector improves the business case for generation projects.[109]
- Increased investment in generation, backed by RiverLink is expected to increase tradable capacity in the South Australian hedge market. The alignment between the preferred

106 AEMO, *Integrated System Plan,* June 2018, pp. 87, 94. Fuel costs savings are the key driver for this initiative according to AEMO. AEMO modelling indicates the interconnector would enable GPG in South Australia to be displaced by a combination of coal-fired generation (outside of South Australia) and renewable energy.

107 AEMO, *Integrated System Plan,* June 2018, pp. 26, 40, 47.

108 Snowy Hydro, *Submission to Electranet*, 30 August 2018

109 Electranet, *SA Energy Transformation*, p. 44, CQ Partners, *SA-NSW Interconnection,* p. 48.

route of the interconnector and two renewable energy zones identified by the ISP will help facilitate the development of new renewable generation.[110]

- Electranet considers the retirement of conventional generation in South Australia over the next decade is unrelated to the development of RiverLink, and sees the project as a remedy to potential generation shortfalls, rather than as a driver of early retirements.[111]
- One participant noted that inefficient gas plants are unlikely to be competitive in the medium to long term and are expected to exit the market regardless of Riverlink.[112]
- The potential for interconnector failure could also be a limiting factor on liquidity. According to CQ Partners, RiverLink's double circuit configuration makes it less likely that it would fail, meaning the risk to hedge markets is relatively small, potentially strengthening confidence in interregional hedging strategies.[113]

From this range of perspectives, it is not clear what impact additional interconnection will have on the availability or price of firm contracts offered into the market.

110 AEMO, *Integrated System Plan,* June 2018, p. 50.

111 Electranet, *SA Energy Transformation*, p. 35.

112 CQ Partners noted that it is likely that these less efficient plants will exit the market regardless of whether interconnection occurs or not. CQ Partners, *SA-NSW Interconnection,* p. 3.

113 CQ Partners, *SA-NSW Interconnection,* p. 7.

E COST BENEFIT ANALYSIS OF MARKET MAKING SCHEMES

This appendix describes the approach taken to estimate the costs and benefits of market making options, and NERA's key findings from its analysis. (A copy of NERA's report was published with the draft determination and is available on the AEMC website). This appendix covers:

- the background and approach used in assessing the market making options
- assessing the costs and benefits of the options
- the costs of market making schemes
- the benefits of market making schemes
- conclusions on the net benefits of additional market making arrangements.

Background

In assessing this rule change, the essential question for the Commission was whether additional market making beyond the ASX market making scheme and the MLO, would be efficient and contribute to the NEO. In order to assess this question, the AEMC put forward four broad market making options for consideration in the consultation paper. These options were to:

- not make a rule, but monitor the effectiveness of the ASX and RRO/MLO schemes
- have a centralised tender process, as proposed in the rule change request
- have a trigger driven obligation
- have a compulsory market making requirement.

The Commission engaged NERA to conduct a qualitative and quantitative assessment of the costs and benefits of these options with a view to establishing two things.

- Firstly, to establish the new baseline level of liquidity that will be delivered via the ASX market making scheme and the RRO/MLO.
- Second, to calculate the incremental costs and benefits of the other options, including the solution put forward by the proponent. This analysis would then inform whether additional market making was required, and if so, what form the additional market making arrangements should take.

The NERA report describes the analysis undertaken and is available on the project website.

An additional market making model was raised with the Commission after it had engaged NERA to complete this modelling exercise. This model is a variation on the compulsory market making model assessed, except it only requires generators to offer contracts to the market, rather than bids and offers. The model is described and qualitatively assessed in appendix h.

Assessing the costs and benefits of the options

The assessment framework that was set out in the consultation paper was also used by NERA in its quantification of the incremental costs and benefits of each market making option. This assessment criteria includes consideration of the extent to which market making will create costs and benefits in relation to:

1. enhancing transparency and predictability
2. enhancing wholesale and retail market competition
3. efficiency of investment in, and retirement of, generation and demand response
4. administrative costs.

In the rule change proposal the proponent observed that market making arrangements have been proposed and introduced internationally without a firm basis for the intervention. These international market making schemes are briefly described in Appendix C and more fully in the NERA report.

NERA agreed with this observation and noted that a consensus has not been reached about how to define liquidity, how much is enough and how liquidity should be measured. It is also the case that market making arrangements have been introduced without a detailed cost benefit analysis of the options, given the challenges of such analysis. The work that NERA has completed should be considered in the context of this challenge, noting the necessity of simplifying the operation of the market in order to provide a reasonable basis for quantification of the benefits.

NERA observed in its analysis that while the costs across international schemes are similar, and therefore easier to quantify, the benefits of market making obligations internationally have been largely elusive and difficult to quantify. The counter-factual is difficult to establish, that being the level of liquidity that would have occurred without a market making requirement. Additionally, all market making schemes internationally have been accompanied by a number of other market reforms designed to improve competition. Isolating the specific impact of market making is therefore difficult.

The costs of market making schemes

The costs of market making schemes internationally are broadly similar. They largely comprise fixed costs in relation to staff and the administration of trading and also variable costs in relation to the costs of collateral and taking sub-optimal or loss making positions from the perspective of the trading firm.

Market making costs are higher during periods of high volatility and when the obligation places tighter constraints on market makers. In designing the market making obligation, there is a trade off between ensuring that market making is provided during periods of high volatility (the benefits of price signals are greatest during these periods) and ensuring that market makers do not bear excessive costs to provide market making during these periods.

Given the trading provisions under the ASX voluntary market making scheme have converged on those required under the MLO, the costs of providing market making under each scheme considered in the cost benefit analysis are largely similar.[114] The costs of market making in the NEM, are based on internationally observable costs adjusted to take account of the higher volatility of the price of electricity contracts in Australia.

The key sources of difference in the costs of each scheme are as follows:

- in the ASX voluntary scheme, market makers can suspend market making during periods of volatility, which will reduce the variable cost of market making.
- the centralised tender process may have lower costs as it enables the participation of financial traders who may be the most efficient market makers. However, the Singapore experience highlights that an inefficient tender design, could result in high costs.
- the trigger driven obligation may have lower costs than a compulsory market making scheme because it is only operational when triggered. In the NEM, this may effectively translate to compulsory market making on an ongoing basis in South Australia, and no other region, depending on the metric used to trigger the obligation. For the purposes of the analysis, NERA assumed, where the obligation is triggered, it is only triggered in the regions where the liquidity metrics have fallen short of the benchmarks set.
- the compulsory obligation may have higher costs if it results in less efficient market makers being selected. It may also distort competition in the market over the longer term, increasing regulatory risk and discouraging investment in generating capacity by those who are subject to the scheme.

The regulatory costs of the incentivised tender, triggered obligation and compulsory obligation are also assessed.

The distribution of costs and who bears them may differ between schemes in the short term. For example, the compulsory scheme imposes costs directly on physical participants, while a centralised tender process passes costs onto consumers or non market making parties.

The benefits of market making schemes

NERA assessed the benefits of each scheme on both a qualitative and quantitative basis.

In qualitative terms, the benefits of market making are that at it addresses issues arising from insufficient liquidity. Insufficient liquidity may impede price discovery, entrench market power, create information asymmetry between market participants and result in inconsistent price signals between the spot market and the contract market. All these factors may make it difficult for smaller and new entrant retailers to compete in the market effectively. By improving the transparency and predictability of forward prices, market making may strengthen wholesale and retail competition, and provide signals for efficient investment.

In quantitative terms, NERA identified the key changes likely to result from a market making arrangement, and how those changes would impact on the operations and costs of retailers and generators. Specifically, improvements in the bid ask spread lower transactions costs for

114 The compulsory market making option assumes the MLO conditions would apply at all times, even though the MLO will only apply in periods the RRO is triggered.

retailers and generators but also encourage increased hedging and a consequent reduction in the amount of risk capital, and the cost of risk capital, required for a retailer to compete.[115]

These competitive effects can be observed through the trade-off that market participants may make between hedging in forward markets and exposing themselves to additional price risk in the spot market.

To perform this quantification NERA constructed a simplified balance sheet for a representative retailer and then ran simulations to examine the implications of changes in electricity prices and customer churn. NERA modelled the impact of the availability of contracts at narrower bid-ask spreads on the optimal hedging strategy. They found that suppliers tend to hedge more when hedges are available at a narrower bid-ask spread.

Lower transactions costs achieved by a market making arrangement therefore result in two categories of benefit:

- a direct financial benefit to competing generators and retailers on the volume that they trade
- allowing generators and retailers to hold fewer assets on their balance sheets to insure themselves against insolvency. Holding fewer assets offers a benefit to market participants equal to the cost of capital or required return on those assets.

NERA's modelling is necessarily an abstraction from reality and includes a number of simplifications, for example:

- the hedging strategy of a representative supplier was used, rather than the individual portfolios of specific retailers. It was also assumed that generators are the counter-party to retailer trades. In practice, this is likely to understate the benefits of a market making arrangement where generators trade frequently or trade between themselves.
- only quarterly contracts were analysed. More rarely traded contracts, such as monthly products, were not considered sufficiently indicative data for the analysis.
- the results assume market participants can hedge their entire position at the lower bid ask spread on mandated products. In practice, spreads across the range of products used, both within and outside a market making arrangement, may not all be at the mandated level.

The degree to which these benefits are delivered depends on the degree of compliance to the scheme specification (trading windows, volumes, bid ask spread) that is assumed, including during periods of high volatility.

Conclusions on the net benefits of additional market making arrangements

NERA concluded that each option has a range of possible net benefits. However, provided the ASX scheme delivers the benefits intended, then there is no additional benefit from adopting additional market making arrangements, irrespective of whether additional intervention is in the form of an incentivised tender, a triggered obligation or a compulsory obligation. This rests on the assumption that market makers comply to the design of the voluntary

115 NERA's assumption of greater hedging refers to a greater level of hedging using the swap products that form the market making scheme.

arrangement and therefore that the benefits in relation to the bid ask spread and the availability of prices and contracts are delivered.

It should be noted that the designs considered in the analysis are all largely consistent, in the products required, lot sizes, market making periods, and bid-ask spreads, and as a result they all have largely the same impact on the market. The comparative results therefore distinguish between market design options, rather than representing assessments of alternative levels of obligation. For example, the bid-ask spreads are not materially tighter in one option than another.

In practice, the different designs may be more or less effective in delivering narrower bid-ask spreads in the wholesale market. Market participants have the option of withdrawing from the ASX scheme periodically over time. Therefore, in principle, the liquidity benefits of this scheme could be lower than the other schemes. However, if the ASX scheme results in a similar market outcome to the other designs, then the net benefits of the ASX scheme could be expected to be greater because it presents cost savings relative to the other designs.

Where the designs lead to a step change in liquidity, as shown in the "MMO+Liquidity" case in the report, the benefits may be significantly greater. However, provided the voluntary ASX scheme achieves what it is intended to do, then this would be the lowest cost option to achieve this outcome.

The net benefits of all the options are greatest in South Australia. This is because the requirement to post regular prices and the required reduction in the bid-ask spread provide for the greatest improvement in transactions costs compared to currently observed levels.

The benefits of the market making arrangements tend to be correlated with costs, under the assumptions used for the analysis. High benefits to market participants equate to higher costs for market makers. This is because the benefits are greatest when market makers make markets at the prescribed spreads during periods of high spot and or contract price volatility. The costs are also greatest in these periods.

Figure E.1 below summarises the net benefits of each scheme.

Figure E.1: NERA costs and benefits of market making in the NEM

Table 1: Estimated net benefits of the proposed MMO designs

	Scenario	[1] ASX MMO + MLO Low	[1] ASX MMO + MLO High	[2] ENGIE's Incentivised MMO Low	[2] ENGIE's Incentivised MMO High	[3] Trigger Driven MMO - SA Only Low	[3] Trigger Driven MMO - SA Only High	[4] Mandatory MMO Low	[4] Mandatory MMO High
Benefits	MMO	10.3	26.3	10.3	26.3	5.2	12.6	10.3	26.3
	MMO+Liq.	22.4	56.0	22.4	56.0	12.2	28.6	22.4	56.0
Costs		13.7	18.6	17.3	19.6	5.9	6.3	17.1	19.2
Net Benefits	**MMO**	**-3.4**	**7.7**	**-7.1**	**6.7**	**-0.7**	**6.3**	**-6.8**	**7.2**
	MMO+Liq.	**8.7**	**37.3**	**5.0**	**36.4**	**6.4**	**22.3**	**5.3**	**36.8**

Source: NERA Analysis

Source: NERA

It should be noted that in incremental terms, none of the additional schemes were assessed to add net benefits above the voluntary ASX market making scheme, assuming the ASX scheme delivers the benefits it is intended to.

Figure E.2 provides a summary of the incremental benefits from market making in situations where the ASX scheme delivers the benefits intended.

Figure E.2: Incremental net benefits of additional market making

Table 5.7: Incremental net benefits from ASX MMO plus MLO – No dropping out

	Scenario	[1] ASX MMO + MLO – No dropping out Low	[1] ASX MMO + MLO – No dropping out High	[2] ENGIE's Incentivised MMO Low	[2] ENGIE's Incentivised MMO High	[3] Trigger Driven MMO - SA only Low	[3] Trigger Driven MMO - SA only High	[4] Mandatory MMO Low	[4] Mandatory MMO High
Benefits	MMO	0	0	0	0	0	0	0	0
	MMO+Liq.	0	0	0	0	0	0	0	0
Costs		0	0	0.7	1.0	0.5	0.5	0.5	0.5
Net Benefits	**MMO**	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**
	MMO+Liq.	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**

Source: NERA Analysis.

Source: NERA

Note: Table assumes base ASX MMO+MLO case delivers all the benefits intended under these arrangements

F COMPARISON OF ASX AND MLO SCHEMES

Table F.1 shows the key requirements of the ASX market making scheme compared to those of the MLO. The scheme designs converged in the last few months of development and are now closely aligned on most requirements. On 30 August 2019, the AER released Interim MLO Guidelines which updated the product set to be included under MLO products.

The Commission understands that market makers in the ASX scheme will receive a monthly compliance report from the ASX on whether they met the terms of the market making agreement. The key terms relate to whether the market maker offered the required product volumes during the required market making periods at the specified bid-ask spreads. If the market makers comply then they are eligible to receive the scheme incentive payments, including exchange fee rebates and a share of profit associated with the growth in trading that the market making scheme delivers.

The AER will not have automatic access to the ASX participant performance reports for market makers, nor does it have powers to compel the ASX to provide specified data. The AER will therefore have to source data directly from participants, or come to an alternative arrangement with participants and the ASX.

Table F.1: **Comparison of market making scheme key terms**

INDICATOR	ASX MARKET MAKING	MARKET LIQUIDITY OBLIGATION
Obligated parties	Corporations agreeing to ASX's market making contract	Generators with 15%+ of scheduled generation in a region.
Number of market makers per region	At least 2 obligated parties in each region. Currently under the ASX scheme there are two market makers in South Australia and one each in NSW and QLD.[2]	
Lot size	1MW	
Minimum volume to be traded per trading period.[3]	5MW (QLD, NSW & VIC), 2MW (SA).	
Products	Base futures (quarterly) only	Base and peak futures (monthly, quarterly, calender and financial year), cap futures (quarterly) and any others approved by AER.[3]
Spread - base load futures	5% or $1/MWh, whichever is higher (QLD, NSW & VIC), 7% or $1/MWh, whichever is higher (SA).	
Spread - cap load futures	na	10% or $1/MWh, whichever is higher
Period of operation	• Commencement: 1 July 2019. • Duration: ongoing. • Tradable period: quarters 2-8.	• Commencement: 5 days from issue of T-3 Reliability Instrument (RI) by AER. Under the SA derogation, the SA Minister can issue a T-3 RI. • Duration: Five days from the issue of T-3 RI until issuing of T-1 RI, or AER determines MLO not needed. • Tradable period: period when liquidity obligation is in effect.
Trading platform	ASX24	AER approved trading facility. RRO transition roles consider ASX24 as an approved facility. AER Interim MLO guidelines allow that approved products are not specific to any particular trading exchange.
Incentives	Exchange trade fee rebate (fixed & growth based), revenue share payment.[4]	None – compulsory scheme.

<table>
<tr><th>INDICATOR</th><th>ASX MARKET MAKING</th><th>MARKET LIQUIDITY OBLIGATION</th></tr>
<tr><td>Periods when parties must market make</td><td colspan="2">25 minutes in each session, except for up to 10 market making sessions at the discretion of the obligated party.[5]</td></tr>
<tr><td>Conditions where market making obligations cease</td><td>• Lack of availability or disruption of the performance of the Trading platform.
• Entering into a contract will cause a participant to break the law.</td><td>• Once net sales limits are reached (for period & region). Daily: 5MWs sessions (except SA – 2MWs); Quarterly: 1.25% of the MLO group's generation capacity, Total: 10% of the MLO group's generation capacity.
• Trading halts on exchange or prohibition imposed on participant.
• Participants can decide not to participate in 10 trading periods of their exchange per month.
• When trading constitutes a breach of s588G or 588V (Corporations Act).
• Any other circumstances set out in AER Guidelines.</td></tr>
</table>

Source: National Electricity Amendment (Retailer Reliability Obligation) Rule 2019; ASX information.

Note: [1] Content on these tables depicts key elements of both market making schemes in summarised format for the purposes of comparison between the two initiatives, please refer to MLO rules and to the ASX for detailed scheme information. [2] Under the MLO there must be at least two "MLO groups". [3] For each Product, the Minimum Quantity of Contracts for each Calendar Quarter in a Market Making Session will be reduced by the number of Contracts in that Calendar Quarter (if any) traded by the MM in that Market Making Session. [4] Formulas to calculate incentives are confidential in nature. [5] Market making session: periods between 11:00am–11:30am and 3:30pm-4:00pm on a business day (both schemes), parties must market make for those two sessions in each day. In general terms, under the MLO an MLO generator performs its obligation if offers are available for at least 25 minutes in each session.

G MARKET MAKING ARRANGEMENTS IN OTHER ELECTRICITY MARKETS

The Commission has reviewed three international jurisdictions that have market making arrangements for electricity futures and one (Ireland) that examined market making in detail and decided against implementing a scheme.

- New Zealand (voluntary)
- Singapore (voluntary)
- United Kingdom (compulsory)
- Ireland (no market making)

The following sections outline the arrangements and experience in those jurisdictions. Further information on these schemes is available in the NERA report[116].

G.1 New Zealand

Four New Zealand electricity generators voluntarily signed market making contracts with the ASX in 2010. This was a reaction to the government's statement that generators had to achieve "satisfactory market liquidity, defined as 3,000 GWh of unmatched open interest" (contracts without matching offsetting contracts) by 1 June 2011. The Commission understands the four market makers receive a rebate on their ASX fees for providing the market making services.

Unmatched open interest did reach the desired level three years after the scheme's introduction. However, for long periods of 2017 and 2018 the bid-ask price spreads exceeded the agreed five per cent limit, sometimes reaching more than 50 per cent. The conclusion was that the voluntary arrangements have supported strong growth in the volume of fixed-price contracts traded and improved retail competition since 2010, but recent wholesale market conditions have put financial pressure on the market makers.

In 2018, the Electricity Authority (EA) commenced its Electricity Pricing Review (EPR). In the review it noted that the contract market had been steadily improving since 2010, however, events during the drought hit winter of 2017 highlighted the fragility of contract market arrangements. The EA concluded that improving the depth and resilience of the contract market should be a high priority.[117]

In the Electricity price review options paper,[118] the EA expressed support for a mandatory market-making obligation. The EA noted that participants should not assume undue risks, but a lack of transparency around market making arrangements makes the voluntary based system fragile and unpredictable. EA argued that compulsory obligations could be introduced relatively quickly and could provide for stress provisions similar to those in place in Britain in order to mitigate risk for participants while improving the resilience of the market.

116 NERA, Costs and benefits of additional market making in the NEM, 24 May 2019

117 https://www.mbie.govt.nz/assets/5ba1054036/first-report-electricity-price-review.pdf

118 https://www.mbie.govt.nz/assets/42ac93a510/electricity-price-review-options-paper.pdf

The EA also stated that it would closely consider the case for an incentive-based scheme in the future. It argued that such as scheme could be funded by a levy on vertically-integrated companies of a certain size. It noted, however, that Singapore's experience suggests an incentive-based scheme would take several years to develop.

In early 2019, following periods of volatility in the NZ futures market over summer 2018-19, the ASX introduced a number of changes to the operation of market making in the New Zealand electricity futures market. These changes adopted exemption terms similar to those in place for the market making scheme the ASX operates in the NEM. The changes also allowed for greater flexibility through a reduced requirement for the volume of contracts offered and provided for greater visibility in the scheme's performance through reporting of the daily performance of market makers to the EA.

The EA's work program for the 2019/20 financial year outlined a hedge market enhancement project for completion in 2020/21. The project's priorities included an evaluation of incentive-based arrangements for market making and a review of the hedge disclosure website.

The operation of the New Zealand Electricity Hedge Disclosure System is described in more detail below. The successful operation of this system in the New Zealand market has implications for the feasibility of such a system in the context of the NEM.

BOX 1: NEW ZEALAND ELECTRICITY HEDGE DISCLOSURE SYSTEM (EHDS)

The EHDS was launched in 2009. It is operated by NZX and overseen by the Electricity Authority. It is a system for the disclosure and comparison of information about risk management contracts. Reportable contracts include swaps, options or fixed-price physical supply contracts. Over 300,000 contracts have been logged into the platform since 2008.

The hedge disclosure system is intended to provide interested parties with a way to compare key risk management contract details. The system is intended to address the lack of information on historic contract curves and allows parties to assess the competitiveness of the risk management contract market. Parties looking to enter into a risk management contract are able to view details of historic contracts in order to assist them when negotiating their own contracts.

All physical participants engaged in hedging activity must report to the platform. The obligation to report to it is given effect by a condition of the *Electricity Industry Participation Code 2010 (NZ).* Only physical participants must report. A Participant must submit data no later than 5 to 10 business days after the trade, depending on the contract type. Subsequently, all trades must be verified by counter-parties within 2 business days.

Trade information disclosed in EHDS

- Contract Price ($/MWh)
- Contract type: swap, option, etc.
- Key dates of the contract

- Volume traded
- Certain common clauses

While trade information to be submitted includes legal names for both parties, trades are de-identified. Other trade information is publicly available on the platform.

Accessible bulk upload and online form options for submissions are provided to market participants. The EA also provides participants with a standard formula for contract price calculation (under s. 13.220 of the Code), which further simplifies the reporting process. Set up costs for the platform are reportedly low.

A full review of the EHDS is expected to be completed by 2021, in line with the EA's work plan.

Source: Electricity Authority (EA) New Zealand.

G.2 Singapore

The Energy Market Authority (EMA) introduced an incentivised market making scheme to provide liquidity in the newly established futures market. The futures market and market making scheme began in April 2015. Market makers receive incentives based on transaction volumes. The EMA also provides a performance incentive using a *pool-price* concept that rewards market makers if a minimum overall market volume is met.

The cost of the scheme (i.e the incentive paid to the market makers) is recovered through retail tariffs and has increased contract market liquidity. The futures market transaction volume is five per cent of the annual underlying physical consumption. The scheme is considered successful by most participants, noting that it has been redesigned twice to adjust the level of incentive payments provided.

G.3 United Kingdom

Ofgem, the UK electricity and gas regulator, introduced a mandatory market making obligation in 2014 to improve wholesale market liquidity. The obligation mandated the six largest generators to provide forward products. The mandated parties had to market make for seven base and six peak products four seasons ahead in two hour-long trading windows per day.

Ofgem is currently assessing whether the scheme should remain given its costs and the removal of the obligation on three of the original six market makers due to their divestment of generation assets to below the stated threshold. Increased liquidity in the market making windows was observed as a result of the scheme, but came at the expense of liquidity in the rest of the trading day.

G.4 Island of Ireland

The Integrated Single Electricity Market (I-SEM) began in October 2018 and is the (net pool) wholesale market for Ireland and Northern Ireland (known as the Island of Ireland). The decision-making authority, the Single Electricity Market Committee (SEMC), considered market making as a way of avoiding low liquidity and market power concerns that were observed in the previous SEM forward market.

A Forward Contract Selling Obligation (FCSO) and a Market Making Obligation (MMO) were both considered but ultimately not implemented. A concern was the additional and disproportionate risks imposed on the obligated parties in a new market that was expected to be highly volatile (at least at the beginning). The SEMC stated they will re-assess the liquidity of the I-SEM forward market 18-24 months after the new market commencement date, which includes monitoring the developments of the UK market making obligation.

H ALTERNATE MARKET MAKING MODEL

After the AEMC had engaged NERA to provide a cost-benefit analysis of the alternative market making schemes, the ASX described a variation for consideration. Rather than requiring the market makers to offer to buy and sell contracts, as is required in the compulsory market making scheme, the variation would require market makers to sell a given proportion of their contracts on-market.

The features of this model, compared to the compulsory market making scheme that NERA modelled, are set out in the table below.[119] The obligation would apply to large vertically integrated participants. Key differences between the models are that:

- the obligation is only to sell contracts
- pricing is not specified in the scheme design.

Table H.1: **Features and comparison of models**

FEATURES	COMPULSORY MARKET MAKING	ALTERNATIVE SUPPLY-SIDE MODEL
Products to be offered	Specified	Specified
Contract volumes	To buy and sell contracts (specified quantities)	To sell contracts only (quantities could be specified or a percentage of generation capacity)
Lot sizes	Specified	Specified
Number of trading days and trading periods	Specified	Specified
Price	Buy and sell contracts within a specified bid-ask spread	No price specified

Source: AEMC
Note: Items listed as "Specified" would be dependent on the scheme design, but are assumed to be the same in both models for the purposes of this analysis.

H.1 Preliminary analysis

This section outlines the Commission's preliminary assessment of this model in the following areas:

- liquidity
- pricing
- competitive conduct
- risk.

119 Notably, the scheme design could vary from that described, which could potentially change the identification of issues and conclusions set out in this appendix.

H.1.1 Liquidity

The scheme would improve the supply of contracts compared to not having a market making scheme. Market participants would have confidence that a quantity of contracts would be available to buy. However, the scheme would likely contribute less to liquidity than compulsory (or other) market making schemes because participants would not be able to trade in and out of positions easily. The ability to buy and sell is a key dimension of a liquid market.

Smaller generators looking to sell contracts would not have any guarantee that the market maker would buy any of their contracts, given there is no buy requirement in this model.

H.1.2 Pricing

The price of contracts would not be specified in the scheme design, but the requirement that a generator sell a given proportion of its capacity on-market means a proportion of its internal contracts at transfer prices would be available to, and observable by, other market participants.

This would provide market participants with confidence that a proportion of their contract prices would be equivalent to the vertically integrated participants' contract costs. However, there would be no visibility of the equivalence of other internal trades.

The design of this type of model needs to consider the restrictions that may apply to a firm in relation to it offering and buying its own contracts. Part 7.10 of the Corporations Act 2001 (Cth) prohibits the creation of a false or misleading appearance of active trading in particular financial products on a financial market (Corporations Act 2001 (Cth), s1041B). The prohibition is deemed to include 'wash trades' where there is no change in the beneficial ownership of the relevant financial products (Corporations Act 2001 (Cth), s1041B(2)). Similar prohibitions are included in the ASIC Market Integrity Rules (Futures Markets) 2017.

The specific design elements around the quantity of contracts made available and time the contracts are available for purchase by third parties, would inform the level of benefit to other market participants.

The relationship between the scheme design and self-trading rules is key. If the scheme requires a participant to trade (not just offer) a given percentage of its generation on-market, and self-trades are not allowed, then the contract prices would have to be adjusted (presumably downwards) until the trading volume requirement was met. Conversely, if the scheme design allows self-trading after a period or in certain circumstances, then the price pressure may be less.

Notably there are additional potential legal issues that would also need to be considered, including potential AFSL implications and relevant limitations to the Commission's rule making powers.

H.1.3 Competitive conduct

As noted, while there would be increased price discovery on a proportion of trades that vertically integrated participants conduct, the broader gaps in market information would not be addressed. In particular, there would be no visibility of the equivalence of other internal trades by the vertically integrated participants. Notably this is also not addressed in the other market making schemes considered, but could be addressed by the increased reporting that is discussed in this determination.

H.1.4 Risk

The scheme would lower the risk to market makers, as it does not expose them to risk on both sides of a transaction. Conversely, other participants would face the higher risks of trading in a market with lower liquidity.

The scheme may increase overall transactions costs, given there would be a higher volume of on-market transactions and these are assumed to cost more than the internal transaction costs of vertically integrated participants.

The market maker also has risk associated with the volume of contracts required in the system design, given it has to meet its internal contracting needs and the requirements of the market making scheme. A vertically integrated participant that was short on generation (overall or in a jurisdiction) may face increased risk if it had to participate in this scheme. However this risk is dependent on the scheme design and is therefore equally present in the compulsory market making scheme.

I AN ADJUSTED CHURN METRIC BETTER INFORMS LIQUIDITY ANALYSIS

Churn is regularly used as one of the indicators of liquidity in financial contract markets. It is calculated as a ratio, comparing the volume of contracts traded with physical demand in a period.

Although it is a widely referenced metric, there is no generally accepted view of the churn level that indicates adequate liquidity. While a ratio less than one is generally seen to indicate a low level of liquidity or that there may not be enough contracts to provide risk management options for the level of physical demand, there is no agreement on when a ratio above one indicates sufficient liquidity. Higher ratios are generally recognised as beneficial because they indicate participants can trade in and out of risk management contracts more easily. Churn is therefore an indicative rather than a definitive metric, and should only be used as part of a broader assessment of liquidity.

In relation to assessing churn in the NEM, there are shortcomings in the calculation of churn and a number of factors need to be considered, including:

- the impact of changes in generation technology and consequent contract types
- the lack of visibility of all forms of contracts
- the impact of ownership changes, in particular vertical integration.

I.1 Technology changes

The change in generation technology taking place in the NEM has implications for the type of financial contracts offered in the market and the supply and demand for different contract types.

Thermal generators have traditionally offered contracts for fixed volumes and fixed prices at specific times. Participants with electricity storage assets, such as batteries and hydro, can also offer firm contracts. Firm contract supply and pricing will vary depending on fuel availability and capacity. Intermittent generators such as wind and solar, generally offer contracts with variable volumes and fixed prices, on an as-generated basis.

As thermal generation has been replaced by intermittent generation, the volume of firm contracts has declined. There are two implications for the churn metric:

- Given intermittent contracts are less likely to be traded on an exchange and so are less visible (see below), the reduction in firm contracts may result in the churn metric indicating a reduction in liquidity. This is because there is an apparent reduction in the supply of contracts but no reduction in demand.
- The different characteristics of intermittent contracts – in particular, that they are longer term and trade infrequently – mean an increase in intermittent contracts, and the

resultant reduction in firm contracts, will likely reduce the churn ratio, even if there is no effective reduction in underlying liquidity[120].

Contract market visibility

In the NEM, electricity contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration). The visibility of these trades varies, with good visibility of trades on the ASX, limited visibility of some OTC trades and no visibility of vertically integrated transactions.

In general terms:

- the majority of firm contracts such as swaps and caps are visible on the ASX, and an additional quantity that are traded in the OTC market and reported by AFMA in its *Electricity Derivative Turnover Report* are also visible
- the dominant form of contracting for intermittent generation are power purchase agreements (PPAs). PPAs are not visible on any exchange or in the AFMA report of OTC trades
- weather derivatives, which may be used in a portfolio with intermittent generation contracts, are not visible on an exchange or in the AFMA report of OTC trades
- demand response contracts are generally not visible in the market
- internal contracting by vertically integrated participants is not visible to the market.

For the churn metric to reflect the underlying level of liquidity, all on-market contracts need to be visible. The churn metric will indicate reducing liquidity if a quantity of contracts that are visible is replaced by the same quantity of a different contract type that are not, even if there is no change in actual liquidity.

Contract characteristics

The different characteristics of intermittent contracts compared to firm contracts mean they are not interchangeable products. The differences also change participants' incentives to offer and buy firm contracts. Intermittent contracts tend to offer variable volumes at fixed prices, on an as-generated basis, as compared to fixed volumes and fixed prices at specific times for firm contracts.

The contract periods are different. Intermittent generation is commonly financed through PPAs. PPAs are often for all or most output from the generator over longer timeframes (for example, 10 to 15 years for a wind farm). For retailers, their attractiveness is in supplying demand at near zero SRMC (within a portfolio of generation assets and contract types), and in delivering the environmental certificates that retailers are required to purchase. Firm generators have traditionally not been financed by long term contracts, and instead sell contracts up to three years ahead, with most volumes two years or less. One implication of longer term contracts is that trading is much less frequent, and the churn metric as a result will indicate low liquidity even if participants have adequate risk management in place.

120 Intermittent contracts are most regularly used to underwrite investment in generation plant, and are therefore long term. Firm contracts are used to secure a specific price for generation at a specific time.

The level of trading in firm and intermittent contracts also varies. Trading in firm contracts is visible on the ASX and in OTC reporting. Trade in PPAs is not visible, but given PPAs underpin longer term investment financing, it is assumed there is limited secondary trading of PPAs. When secondary trading does occur, it is likely to be to third parties (such as smaller retailers or C&I customers) for a proportion of output that is packaged with other generation as firm contracts (at which point the trades are visible on the ASX or OTC markets – although the underlying generation technology that underpins such contracts is not disclosed).

Participant incentives

A generator's willingness to offer firm contracts will be limited by its expectation of dispatch. It will only offer firm contracts that it expects to be able to defend. Given intermittent generation has a short run marginal cost advantage over thermal generation, increasing quantities of intermittent generation can be expected to reduce the incentives to offer firm contracts, and/or to limit the times at which firm contracts are offered (to take account of likely dispatch, minimum run times, ramp rates). When firm contracts are offered, it may also be at higher prices, to maintain plant viability at lower utilisation rates. If lower contract quantities are not offset by higher contract prices, this may contribute to the closure of firm generation.

A participant's willingness to buy firm contracts will be informed by its expectations of output from intermittent generation. If a participant expects to meet high levels of demand through intermittent generation and contracts, it will buy less firm contracts. Conversely, if it expects low levels of demand to be met by intermittent generation, it is likely to seek more firm contracts.

Measuring churn

The impact on liquidity of the change in contract types (from firm to intermittent) is dependent on the relationship between the quantity of firm contracts available compared to the load that requires firm contracts (ie the load that is not supplied by intermittent generation).

In practice, there will be no change in the actual level of liquidity if the reduction in firm contracts in the market is accompanied by a commensurate reduction in the load expected to be supplied by firm generation. To put this another way, there is no change in underlying liquidity if the reduction in firm contracts is proportionate to the expected increase in load that is supplied by intermittent generation. It is only if these changes, between firm and intermittent contracts compared to load supplied by firm and intermittent generation, are not proportionate that there will be a change in the effective level of market liquidity.

A practical way to understand this relationship is to separately calculate a churn metric for firm and intermittent contracts; the quantity of intermittent contracts traded compared to the demand (energy) that is supplied by intermittent generation; and, the quantity of firm contracts traded compared to the demand (energy) that is supplied by firm generation.

I.2 Vertical integration

Ownership changes in the NEM have resulted in increasing vertical integration between retailers and generators. This has meant a proportion of contracting that previously occurred on-market between participants has been internalised by vertically integrated participants. Transactions that were visible to the market have become internal off-market transactions. These ownership changes are likely to reduce the churn ratio, as the quantity of contracts visible in the market decreases without any change in demand.

However, the effective change in liquidity resulting from greater vertical integration depends on whether there has been an actual change in the contracts available to market participants. For example, if a retailer bought generation assets to supply its level of demand (rather than buying contracts for that level of demand), then there would be no effective change in the liquidity of contracts available to other market participants. Whereas if the retailer bought generation in excess of its level of demand, then liquidity will decrease unless the contracts for the excess generation are offered to market participants.

In a competitive market, a vertically integrated participant can be expected to maximise the value of its assets, and therefore would be expected to offer contracts against any generation that is in excess of its expected level of retail demand. In these cases, there would be no effective change in liquidity for merchant (non-vertically integrated) participants. However, if increasing vertical integration and the associated increase in market concentration resulted in market power (permanent or temporal), then contracts may be withheld or priced at higher levels than a more competitive market may deliver.

I.3 An adjusted churn metric

In order to address the issues described, three adjustments to the traditional churn calculation are required to enable a more accurate picture of liquidity in the contract market:

- separately calculate churn metrics for firm and intermittent contracts compared to firm and intermittent demand (energy dispatched) respectively.[121]
- merchant contracts should be compared to the sum of merchant generation and generation in excess of vertically integrated participants' demand.[122]
- all contract types need to be visible for an accurate calculation of churn.

121 This does not account for behind-the-meter generation (negative demand).

122 Market power would be assessed with reference to the quantity of contracts made available compared to generation capacity.