Quarterly Compliance Report:

National Electricity and Gas Laws

1 July – 30 September 2017

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Contents

Executive Summary

The Quarterly Compliance Report (QCR) outlines the Australian Energy Regulator's (AER) compliance monitoring and enforcement activity under the National Electricity Law (Electricity Law) and the National Gas Law (Gas Law), including the rules and regulations which sit under those laws. It emphasises the importance of compliance to the efficient operation of gas and electricity markets for the benefit of consumers, market participants and large energy users.

The AER reports on the outcomes of its monitoring, enforcement and investigation activities. Through the publication of this information we seek to educate and inform consumers, businesses and other stakeholders by highlighting compliance issues and/or raising awareness of market participant obligations. This reporting promotes energy market transparency and good industry practice.

This QCR covers the period 1 July 2017 to 30 September 2017 (the September 2017 quarter). It includes reporting on the following matters in gas and electricity markets.

Gas

Gas Bulletin Board

The AER monitors participant compliance with data reporting requirements for the Natural Gas Services Bulletin Board (the Bulletin Board). This QCR provides an overview of the new Bulletin Board reporting requirements to take effect in September 2018. We also outline some compliance matters, including Santos's September 2017 restatement of data for Moomba LBD Storage, which revised the facility's storage level down by 10 petajoules.

Sydney Demand Forecasting Errors

An update is provided on the AER's analysis of pronounced incidences of over forecast demand in the Sydney Short Term Trading Market (STTM) across 2016 and 2017. The AER has been reporting on this matter in recent QCRs. We have continued our analysis during the September quarter, with further focus on the forecasting performance of AGL Energy, which has exhibited the highest incidence of demand forecasting errors among Sydney hub retailers. We report an improvement in AGL's performance during the September quarter.

Pipeline Capacity Availability

Following changes, in 2016, to the way that Epic Energy calculated pipeline capacity to the Adelaide STTM, the AER examined the methodologies used by owners of other STTM-connected pipelines to calculate available capacity to STTM hubs. We outline our conclusions here, including our view that pipeline capacity calculations are delivering efficient outcomes.

AGL Allocation Error

We report on the allocation error by AGL Energy, for the Sydney Short Term Trading Market (STTM).

Retail Market Procedures

We have updated our standing item on non-compliances with the Retail Market Procedures.

Electricity

NEM Summer Readiness

Preparedness for the 2017/18 summer is a principal component of the electricity section of this QCR. We build on work currently underway by AEMO and industry stakeholders by outlining key obligations on participants that the AER considers critical to ensure that the National Electricity Market (NEM) provides secure and reliable electricity to consumers throughout the forthcoming summer period.

We provide messaging to electricity market participants to clearly outline our expectations regarding compliance with a number of critical obligations under the Electricity Rules. We consider it is important to provide this messaging following market events that occurred last summer, particularly because forecasts for the upcoming summer suggest that at times there may be a lack of reserve to meet the reliability standard.

The AER has investigated a number of market events that occurred last summer. A key finding of our investigations has been that it is essential for participants to provide high quality and timely information to AEMO to ensure the secure and reliable operation of the power system. The provision of high quality information allows AEMO to identify and respond to any issues that arise, in the most effective way and at the least cost to consumers.

The NEM is currently in a transitional phase. There has been an emergence of new technologies and some traditional generation plant has been retired. At the same time, the Electricity Rules are being adapted with urgency to ensure they keep pace with new and changing requirements around the security and reliability of the power system. It is important for the industry as a whole to be cognisant of this transition and to act to ensure that any associated risks are managed. We consider it is crucial for all participants and institutions to assist where they can to achieve a successful transition.

We encourage participants to review their practices in light of this information and to update them, as appropriate, in readiness for this summer.

High price events in the NEM

We provide an overview of reporting on high price events in the NEM.

Commencement of Power of Choice Rule Changes – 1 December 2017

With the December 2017 transition to metering contestability now imminent, we outline our staged 2017 review of compliance with metering upgrade requirements in Chapter 7 of the Electricity Rules. We detail the new arrangements for metering contestability, the staged transition model agreed by industry and the arrangement for enhancement of retail competition within embedded networks.

Instrument Transformer Testing

The Electricity Rules require Responsible Persons to test metering installations for accuracy every ten years. During 2017, we have reviewed compliance with the testing requirements for low voltage current transformers, and provide an update on our work during the September 2017 quarter. We also set out our expectations regarding the transition of the instrument transformer testing role on 1 December 2017 from “Responsible Persons” (distributors and retailers) to Metering Coordinators.

Generator Rebidding

There is an update to our standing item on generator rebidding in the National Electricity Market (NEM). We report on our analysis of rebidding activity, including the notices that we have received from participants regarding rebidding errors.

Background

The AER is responsible for monitoring, investigating and enforcing compliance with the obligations under the National Electricity Law, National Gas Law, National Energy Retail Law and the respective rules and regulations governing Australia's wholesale energy markets, including those applying to network service providers (NSPs). Section 15 of the Electricity Law and section 27 of the Gas Law set out our functions and powers, which include:

- monitoring compliance by energy industry participants[1] and other persons; and
- investigating breaches, or possible breaches, of provisions of the legislative instruments under our jurisdiction.

Consistent with our statement of approach,[2] we aim to promote high levels of compliance, and seek to build a culture of compliance in the energy industry. A culture of compliance will:

- reduce the risk of industry participants breaching their regulatory obligations; and
- assist in ensuring industry participants can engage confidently in efficient energy markets.

As part of this process, we undertake an ongoing compliance risk assessment of each obligation under the Electricity and Gas Rules to identify appropriate focus areas and monitoring/compliance mechanisms. The risk assessment involves the analysis and ranking of each obligation to determine its compliance risk, based on the probability of a breach and its impact on energy market participants. Our monitoring/compliance mechanisms include our strategic compliance projects, audits, reporting requirements, market monitoring, and targeted compliance reviews.

In selecting the areas for review, we adopt the following principles.

- Consideration of risk (the greater the risk, the higher the priority).
- A commitment to ensuring that both systemic issues and those with the potential for isolated but significant impact are addressed.

In carrying out our monitoring functions, we aim for:

- cost effectiveness for energy industry participants and the AER; and
- transparency (subject to confidentiality requirements).

In carrying out our enforcement actions we seek to demonstrate proportionality and procedural fairness (where required).

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1 Entities registered by AEMO under Chapter 2 of the Electricity Rules or in accordance with Part 15A of the Gas Rules.

2 The Statement of Approach is published on the AER's website. In April 2014, the AER released a combined Enforcement and Compliance Statement of Approach covering our functions under the Gas Law, Electricity Law and National Energy Retail Law. The document reflects the consistent approach taken by the AER to enforcing the energy laws across all markets.

We take into account a participant’s compliance framework when determining our response to potential breaches. In assessing compliance culture, we consider whether compliance programs and processes are effectively applied, up-to-date and tested regularly. Whilst businesses may not be required to have a compliance framework in place it is good governance to do so.

1 Gas

We are responsible for monitoring, investigating and enforcing compliance with the Gas Law and Rules, including but not limited to the Short Term Trading Market (STTM), the Bulletin Board, Victoria's Declared Wholesale Gas Market (DWGM) and the Gas Supply Hubs (GSH).

This part of the report provides an update on investigations, compliance matters and projects in the gas markets.

1.1 Natural Gas Services Bulletin Board

1.1.1 Bulletin Board Reporting Arrangements

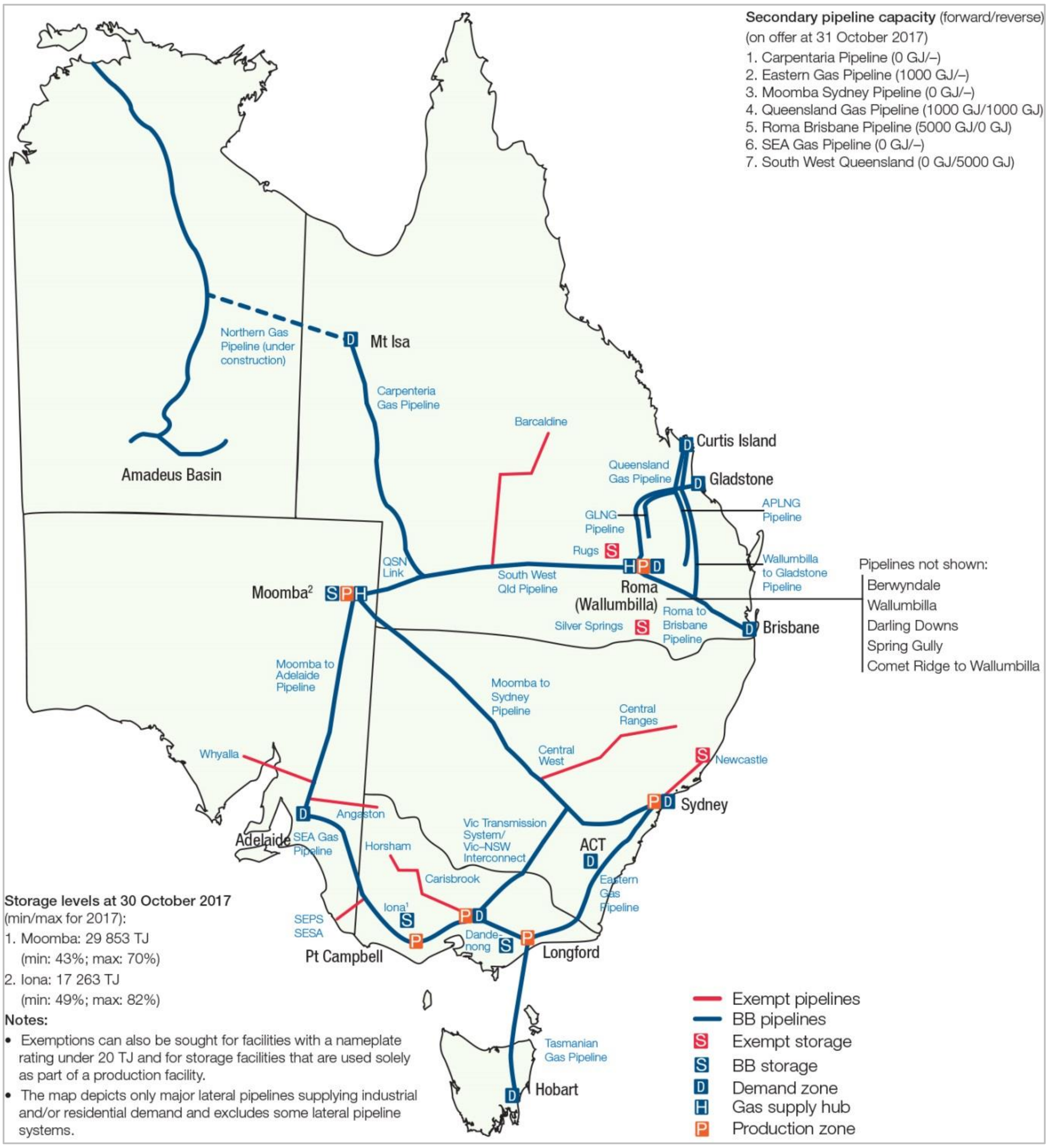
The Natural Gas Services Bulletin Board (Bulletin Board) website depicts the daily operation of Australia's interconnected east coast gas markets. Under the National Gas Law, AEMO is responsible for collecting and collating information in relation to natural gas services and for publishing information on the Bulletin Board. Persons responsible for that information must report it to AEMO in accordance with the National Gas Rules.

The AER is responsible for monitoring compliance with Bulletin Board requirements under the Gas Law and Gas Rules (and Regulations). This includes monitoring the reporting of information by Bulletin Board facility operators.

Figure 1 below depicts current Bulletin Board reporting arrangements. Reporting requirements are based on a zonal model that presents gas flows between production and demand zones. Exemptions may apply to transmission pipelines that do not transport gas between zones and to storage facilities and production facilities that are not directly connected to these pipelines. Accordingly, various lateral pipelines and storage and production facilities do not appear on the Bulletin Board.

Facilities that currently receive reporting exemptions under the zonal model include Silver Springs Gas Storage and Roma Underground Gas Storage, both located in South East Queensland. The daily activity of these facilities, including gas held and historical injections and withdrawals, is not visible to east coast gas market participants and observers. New Bulletin Board reporting requirements will take effect in September 2018, capturing these facilities and promoting more consistent reporting across the interconnected east coast gas market.

Figure 1: Natural Gas Services Bulletin Board (31 October 2017)



1.1.2 Bulletin Board compliance matters

Market participants connected to the east coast gas grid must report their activity in accordance with Part 18 of the Gas Rules and consistent with the processes outlined in AEMO's Natural Gas Bulletin Board Procedures. The AER monitors the standard of this reporting for compliance. From October 2016, additional reporting requirements were imposed on Bulletin Board facilities under the Australian Energy Market Commission's (AEMCs) *National Gas Amendment (Enhanced Information for Gas Transmission Pipeline Capacity Trading) Rule 2015*. Additional reporting requirements will be imposed from September 2018 under the AEMC's *National Gas Amendment (Improvements to Natural Gas Bulletin Board) Rule 2017*.

Through our monitoring of Bulletin Board reporting standards over the first half of 2017, we observed some data errors and late data submissions but noted general improvement in the timeliness and accuracy of reporting.

Having said that, we considered the following compliance matters this quarter:

Moomba LDB Storage

Gas Rule 169B requires Bulletin Board storage facilities to provide, to AEMO on each gas day, the actual quantity of natural gas held in storage.

On 18 September 2017, Santos restated the storage volume at its Moomba Lower Daralingie Beds (LBD). Santos submitted revised data to the Bulletin Board, reducing the volume from 39 887 TJ to 29 850 TJ.

The AER contacted Santos seeking an explanation for the reporting anomaly. Santos attributes the change to multiple factors, including:

- Gas being produced from production wells adjacent and connected to the LBD reservoir, effectively drawing down storage levels.
- A minor metering error affecting long term data, which was identified during a recent audit of activity at Moomba.

Santos further indicated that it had resolved these issues and that the current injection and withdrawal data, for Moomba LDB, is in line with forecast expectations.

We are currently working with Santos to further understand the reasons behind the data revision and the nature of its reporting. The Bulletin Board is an important information platform. It informs commercial, regulatory and policy decisions and observers should be able to consult the Bulletin Board with confidence that its data is reliable. We remind Bulletin Board facility operators of the importance of accurate reporting, emphasising the CoAG Energy Council's agenda to develop the Bulletin Board into a one-stop-shop for information on east coast gas markets. This is especially important in light of the current tight supply demand situation in these markets.

Tasmanian Gas Pipeline

Gas Rule 171A requires registered pipeline operators to provide 12 month outlooks of uncontracted primary pipeline capacity. The outlooks must be submitted according to AEMO's Natural Gas Services Bulletin Board Procedures and in the format specified in AEMO's Guide to the Natural Gas Services Bulletin Board CSV File Transactions. Pipelines with bidirectional capabilities must submit forward and reverse outlooks according to AEMO's Bulletin Board CSV File Transactions. Tasmanian Gas Pipeline (TGP) became a bidirectional pipeline in November 2016 with the commissioning of TasHub (enabling flows into Victoria). During the September quarter, the AER identified that the TGP was reporting uncontracted capacity outlooks for forward pipeline flows (TRANC) only, rather than outlooks for pipeline flows in both the forward and reverse (REVC) directions.

The AER raised the matter with both AEMO and the operator of the TGP, seeking the publication of forward and reverse capacity data. As a result of our inquiries, uncontracted pipeline capacity outlooks (TRANC and REVC) are now published on the Bulletin Board for the TGP.

1.1.3 Bulletin Board reform

Further Bulletin Board reforms will be implemented in 2018. At the request of the CoAG Energy Council, the Australian Energy Market Commission (AEMC) has progressed a new rule change proposal to the final draft stage. The amendment to Part 18 of the Gas Rules was published in September 2017 and is scheduled to take effect from 30 September 2018.[3]

Gas market participants should be aware of the future changes to their reporting obligations. The rule change removes the link between the obligation to report and the zonal model. This will remove many existing reporting exemptions, bringing facilities connected to east coast gas markets under more consistent reporting arrangements. New obligations will also impose additional layers of reporting on facilities that already report. Other facilities will be required to report for the first time.

The new reporting arrangements, in 2018, will include:

- reducing the reporting threshold for transmission pipelines, productions facilities and storage facilities to a minimum of 10 TJ/day (reduced from the current 20TJ/day);
- requiring detailed reporting by production and compression facilities, including daily nominations, intra-day renominations and short term forecast nominations (D+1 to D+6 daily);
- requiring pipeline operators to submit daily disaggregated receipt/delivery point data; and
- imposing reporting obligations on regional pipelines and facilities attached to distribution pipelines.

Market participants should also be aware of the strengthening of the compliance framework through expanded civil penalty provisions. Obligations to register as a Bulletin Board participant will be subject to civil penalties under the new rules. Registered participants will also be required to comply with an information standard which will apply to the accuracy and timeliness of data provision. This requirement will be both a conduct and civil penalty provision.

1.2 Short Term Trading Market

1.2.1 Sydney demand forecasting errors

Demand forecasts submitted by trading participants are the primary input for AEMO scheduling and form the basis for calculating ex-ante prices in the STTM. Poor demand

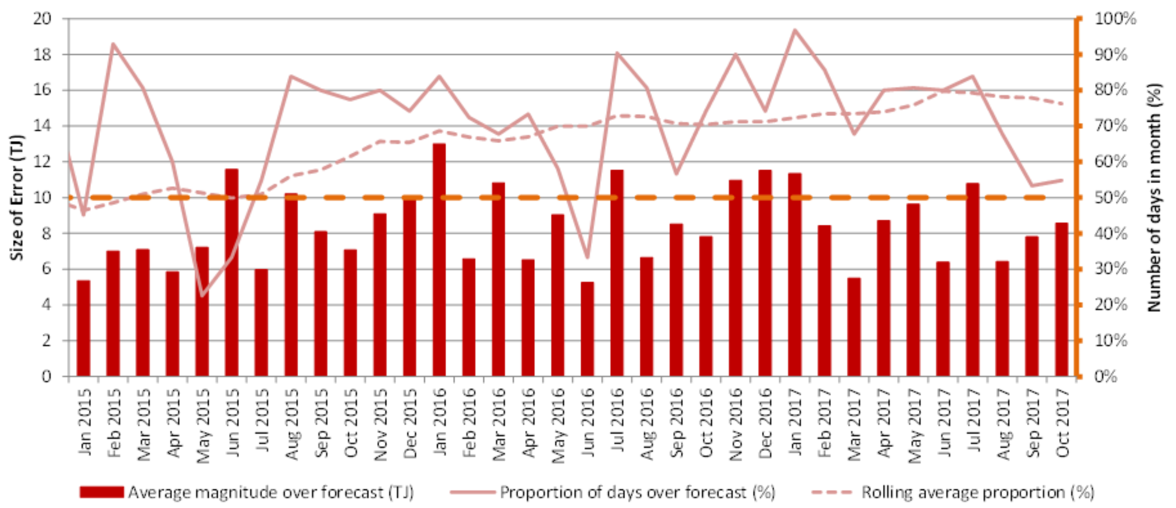
3 http://www.aemc.gov.au/Rule-Changes/Improvements-to-Natural-Gas-Bulletin-Board

forecasting leads to inefficiencies in dispatch whereby the ex-ante price is set on the basis of a higher or lower quantity of gas than is required. It can lead to higher market operator service (MOS) payments in the STTM. Large amounts of gas are required to address the imbalance, adding to participant business costs.

Gas Rule 410 requires each STTM trading participant who expects to withdraw quantities of natural gas from a hub on a gas day to submit, in good faith, ex ante bids or price taker bids (and any revisions to those bids) that reflect the participant's best estimate of the volume it expects to withdraw that day. These bids, in effect, reflect each participant's demand forecast.

The AER continually monitors demand forecast accuracy across the STTMs. Since late 2014, there has been a clear trend toward high incidences of forecasting inaccuracy in the Sydney hub, specifically in relation to over forecast demand. **Figure 2** shows the persistence of this trend since January 2015.

Figure 2: Sydney Hub forecasting performance metric (since January 2015)



Over forecast demand was particularly prevalent during the 2016/17 summer period, nearing 100 per cent of days across January 2017. It remained high over the ensuing six months, persisting at approximately 80 per cent of days from April to July (based on preliminary allocations data).

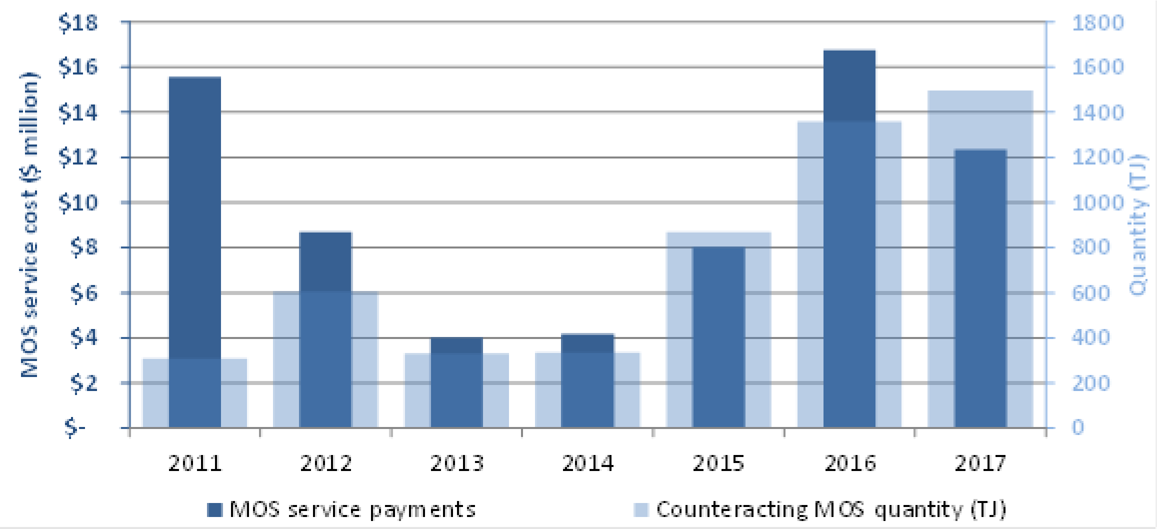
During 2017, the AER has been working to achieve a better understanding of the causes of Sydney demand forecasting errors, including the role of AGL Energy, the largest contributor across the period of over forecasting identified at **Figure 2**. We have met with AGL and other Sydney hub participants and they have communicated their efforts to improve the accuracy of their forecasting by employing new models and improving their understanding of the usage patterns of their customers.

As **Figure 2** indicates, there was an improvement in the hub-wide provisional data during the September quarter of 2017. The number of over forecast days declined from 84 per cent of days in July to 53 per cent of days in September. AGL over forecast its demand on 53 per cent of days during the September quarter compared to 86 per cent of days during the first six months of 2017. The 12 month rolling average indicator of over-forecasting is also trending down towards a less biased result. All of these indicators suggest improvements in AGL's demand forecasting.

We note that under forecast demand and over forecast demand add to participant business costs. While deviations between forecast and actual demand are expected, the AER monitors gas wholesale markets for persistent forecasting bias. We also monitor MOS gas volumes and offers, noting that the costs associated with any bias will be influenced by the size of the deviation and the offer price.

Figure 3 shows annual MOS service costs at the Sydney hub since 2011 (2017 costs are to 31 October). While 2017 costs are trending toward 2016 levels, the rate of the month-to-month increase has slowed, with $2.8 million added to service costs across the three months of August to October, compared to $9.5 million over the first seven months of the year. Although we still recognise that MOS service costs remain historically high, AGL's recently improved demand forecasting performance is a positive development.

Figure 3: Sydney MOS service costs and CMOS since 2010



Note: 2 TJ of Counteracting MOS allocations are defined as 1 TJ of increase MOS services provided to the hub offset by 1 TJ of decrease MOS services on another pipeline. This is generally in the form of decrease MOS allocations on the pressure controlled Moomba to Sydney Pipeline (MSP) and increase MOS allocations on the Eastern Gas Pipeline (EGP). **Figure 3** shows available data from 27 July 2010 to end of October 2017.

Counteracting MOS

While MOS volumes are mostly related to levels of demand forecast error, they also reflect counteracting MOS volumes. This type of MOS results from a requirement for balancing gas, regardless of the accuracy of demand forecasts. In such cases, hub demand is not met by pipelines that individually flow at their scheduled volumes. Instead, pipeline flows collectively match forecast hub demand, with some pipelines injecting either more or less than expected. The balancing gas required on each pipeline adds to MOS service costs.

The AER has observed a high incidence of counteracting MOS, at the Sydney hub, across the 2015–17 winter periods. We will report further on Sydney MOS trends in upcoming QCRs.

1.2.2 Pipeline capacity availability

Gas Rule 376(f) requires operators of STTM-connected pipelines (as STTM facility operators) to submit to AEMO the capacity that is to be used as the default capacity of the pipeline to deliver gas to the STTM hub. More specifically, Rule 414(1) requires they must submit, on each gas day, their expectation of the quantity of gas that the pipeline is able to deliver to the hub on each of the proceeding three gas days. They must do so in 'accordance with good industry practice'.

The AER last audited the capacity information submitted by STTM-connected pipeline operators in 2013. Given the evolving nature of the east coast gas market, including physical changes to pipeline infrastructure, the AER has re-examined the quality of pipeline capacity information, including the methodology used to calculate pipeline capacity into STTM hubs. Recent changes include Epic Energy's new calculation methodology for gas deliveries to the Adelaide hub on the Moomba Adelaide Pipeline System (MAPS). This change was made in 2016 and pipeline capacity into Adelaide now better reflects the maximum pipeline capacity available to Users in Adelaide given users' ability to re-nominate across delivery points (at Adelaide and upstream of Adelaide) on a gas day.

During 2017, the AER contacted the operators of the Eastern Gas Pipeline (EGP), SEA Gas Pipeline and Moomba Sydney Pipeline (MSP) regarding their respective pipeline capacity calculation methodologies. These pipeline operators (including Epic Energy[4]) determine the pipeline capacity available to their respective hubs in different ways according to the requirements of upstream users and physical pipeline characteristics. The approaches are, however, consistent in so far as upstream delivery capacity can be made available to the respective hubs when that capacity is not utilised.

The AER is satisfied that the operators of STTM-connected pipelines are meeting these requirements.

1.2.3 AGL allocation error

As part of its responsibility for ensuring efficient price outcomes in Short Term Trading Markets (STTMs), AEMO relies on participants to submit gas allocations data. This data refers to the quantity of natural gas allocated to a participant on a previous gas day. The allocations are used to confirm that a provider's nominated (before the gas day) gas volumes equate to their actual (on the day) volumes. Incorrect allocations data can have significant cost implications, as higher priced gas may subsequently be required to meet demand than that established in AEMO's provisional schedule.

Under clause 419 of the Gas Rules, a STTM facility is required, on each gas day, to submit a STTM facility allocation for the previous gas day. AEMO uses this to calculate an ex-post imbalance price, which in turn is used to determine the deviation payments or charges for

4 The AER examined Epic Energy's methodology change in 2016.

trading participants.[5] STTM facilities provide allocations notices via an electronic allocation file.

For the 19 July 2017 gas day, AGL submitted a zero allocation, rather than a 30 090 gigajoule (GJ) allocation from the Newcastle gas storage facility, for the Sydney STTM. This meant that 30 090 GJ of unaccounted for gas was delivered to the Sydney hub.

AGL reported the error to AEMO and the AER. AGL determined that the error resulted from a manual process where a trader copies a number into an electronic file ready for submission. AGL has reviewed this process and the 'copy' step has now been automated.

Part 20 of the Gas Rules outlines the requirements for participating in short term trading markets including requirements for submitting gas allocations, where a facility operator may be supplying gas to the hub on its own behalf. Rule 369 establishes an information standard for STTM participants, stating that participants must prepare and submit information or data, and maintain equipment from which that information or data is derived, in accordance with good industry practice.

The Rules also provide arrangements whereby trading participants can request that AEMO investigate a scheduling error, with allowances for compensating trading participants that have incurred associated costs. We understand that AEMO has not received an investigation request in relation to the AGL allocation error.

In view of AGL's self-reporting and efforts taken to address the reason for the error, the AER has decided to take no further action on this matter at this stage.

STTM participants are reminded of their obligation to maintain high-quality data and effective data submission processes, as doing so is essential for reaching efficient price outcomes and maintaining confidence in short term trading markets.

1.3 Gas Supply Hub

1.3.1 Wallumbilla single market product (optional hub services)

On 28 March 2017, the Wallumbilla Gas Supply Hub transitioned to the optional hub services model. The hub's three trading locations[6] were replaced by a single trading location at Wallumbilla and an in-pipe Roma Brisbane Pipeline (RBP) trading location at South East Queensland.[7]

Commensurate with the introduction of the optional hub services model was the introduction of a spread product platform enabling the physical trading of gas between Wallumbilla and South East Queensland. As such, participants with transportation rights have been able to

[5] https://www.aemo.com.au/media/Files/Other/STTM/STTM%20ER%2015002%20Delayed%20allocation%20submission%20%20Sydney%20%2016%20June%202015.pdf,

[6] Formerly, liquidity at the Wallumbilla Exchange was spread across three trading locations at the Queensland Gas Pipeline (QGP), South West Queensland Pipeline (SWQP) and the Roma Brisbane Pipeline (RBP).

[7] Trades which previously occurred at the RBP in-pipe trading location are now traded under the separate product established for South East Queensland (SEQ). All other products traded at the former RBP, SWQP and QGP trading locations are now traded under the new Wallumbilla single product (WAL). The transition occurred from 28 March 2017.

arbitrage price between the two locations. The first spread product trade occurred in the Wallumbilla gas supply hub on 12 June 2017. A further 27 spread products were traded to 31 July and a total of 52 spread products were traded for the September quarter.

1.3.2 The Moomba Hub

A new gas supply hub was established at Moomba in June 2016, to facilitate trade on the Moomba Sydney Pipeline (MSP) and Moomba Adelaide Pipeline (MAP) and to enable trade between Wallumbilla and Moomba. Despite a number of offers and bids, there has been no significant trade at the Moomba hub, with only one transaction made, for 2 TJ of gas, on 18 September 2017.

1.4 Retail Market Procedures

Under the Gas Law, AEMO has the ability to make procedures regulating a retail gas market (Retail Market Procedures).[8] Queensland, Victoria, New South Wales and the ACT and South Australia each have their own Retail Market Procedures. The procedures impose a number of obligations on participants including in relation to the provision of metering data, the Gas Interface Protocol[9], customer transfer processes and settlements. Section 91MB of the Gas Law provides that AEMO and each person to whom the Retail Market Procedures (Procedures) are applicable must comply with the Procedures.

In the event that AEMO has reasonable grounds to suspect a breach of the Retail Market Procedures, it is required under the Gas Law to determine if the breach is material. If AEMO decides the breach is material, AEMO must publish its decision and the reasons for it on its website. AEMO may direct the person suspected of the breach to rectify it or to take specified measures to ensure future compliance (or both). AEMO may also decide to refer the breach to the AER.

If AEMO decides that the breach is immaterial, it must publish the reasons for its decision on its website. It must also provide a copy of its decision to the AER.

AEMO has published its compliance process for the Retail Market Procedures[10]. The publication outlines the criteria that AEMO uses to determine that apparent breaches of the Retail Market Procedures have occurred and whether the apparent breaches are material or immaterial.

This quarter, AEMO did not report any material breaches of the Retail Market Procedures but did report one immaterial breach by a participant. AEMO also self-reported immaterial breaches and provided the details of these breaches to the AER as required. AEMO also provided details of the corrective measures taken to address these breaches. The AER is satisfied with the materiality classification of the breaches and the corrective measures taken by AEMO in relation to the breaches.

8 See sections 91M and 91MB of the National Gas Law.

9 The Gas Interface Protocol governs the manner and form in which information is to be provided, notice given, notices or documents delivered and requests made as contemplated by the Retail Market Procedures (NSW/ACT).

10 http://www.aemo.com.au/-/media/Files/PDF/0090-0014-pdf.pdf

This quarter AEMO reported the following immaterial breaches of the Retail Market Procedures:

- AEMO's non-compliance with the SA Retail Market Procedures relating to the calculation of the Heating Degree Day (HDD). In preparation for the close down of the Kent Town weather station, AEMO discovered that between 13 October 2014 and 17 May 2017, historical hours of sun (HoS) data were used to calculate the Heating Degree Day (HDD) for the Adelaide region, as no observed nor forecast HoS data was received. AEMO noted that it will update the internal procedures to include follow up steps when weather data from the Bureau of Meteorology is not received.

- Energy Australia's non-compliance between 30/03/2017 and 02/05/2017 with the requirement to obtain explicit informed consent from customers in accordance with requirements of clause 5.1.2 of the NSW-ACT Retail Market Procedures. This issue affected 23 gas sites, which subsequently were returned to the previous retailers. Energy Australia implemented additional measures to ensure that this issue is unlikely to reoccur in the future.

- AEMO's non-compliance, on 26/06/2017, with the requirement to meet timely provision of the Network Allocation Data (NAD) file for the NSW and ACT Gas Retail Market to the Short Term Trading Market (STTM) system. The data was delayed by one hour and 46 minutes due to a server related issue.

- AEMO's non-compliance with the timely provision of the Shipper profiled forecast market reports to Red Energy between 07/07/2017 and 14/07/2017. This delay was as a result of an incorrect name for Red Energy's folder.

- AEMO's failure to provide timely delivery of the transfer confirmation of metering data on 12/07/2017 as a result of a connection error that stopped the processing of the transfer notification transactions.

- AEMO's failure to provide acknowledgement within 270 minutes for medium priority transactions on 17/08/2017 as required in accordance with the SA Retail Market Procedures. These transfer Confirmation Notification (TFR-CONF-NOTF) transactions were delayed for 77 transactions as a result of a system related issue.

- AEMO's failure on 19/08/2017 to provide Network Allocation Data (NAD) file for the NSW and ACT Gas Retail Market to the Short Term Trading Market (STTM) within the required timeframe as a result of a system related issue.

2 Electricity

We are responsible for monitoring, investigating and enforcing compliance under the Electricity Law and Rules. This part of the report provides an update on investigations, compliance matters and projects in the electricity market.

2.1 NEM Summer Readiness

The AER is providing this messaging to electricity market participants ahead of this summer to clearly outline our expectations regarding compliance with a number of critical obligations under the Electricity Rules. We consider it is important to provide this messaging following market events that occurred last summer, particularly because forecasts for the upcoming summer suggest that at times there may be a lack of reserve to meet the reliability standard.

AEMO's Electricity Statement of Opportunities (ESOO) evaluates and compares committed electricity supply information provided by industry with operational consumption and maximum demand forecasts, to identify potential unserved energy in excess of the reliability standard over a 10-year outlook. This aims to provide market participants with information to help them make informed decisions about investment potential in the NEM. The 2017 ESOO concluded that *"the radically changing dynamics of the power system are resulting in a tight supply-demand balance in parts of the NEM. The overall responsiveness and resilience of the system is at risk from increased vulnerability to climatic events, such as extended periods of high temperatures, and the risk of loss of, or reduction in output of, major generation units"*.[11] AEMO's analysis identified a heightened risk that the current NEM reliability standard will not be met and that in summer periods, targeted actions may be necessary to reduce the risk of supply interruptions.

The AER has investigated a number of market events that occurred last summer. Amongst other things, this involved a review of generators' compliance, where we sought information on practices and processes they have in place to ensure compliance with the relevant Electricity Rules obligations. Our preliminary findings have informed this summer readiness messaging and our view of industry best practice. These investigations have guided how the AER will focus its market monitoring activities leading into summer.

A key finding of our investigations has been that it is essential for participants to provide high quality and timely information to AEMO to ensure the secure and reliable operation of the power system. The provision of high quality information allows AEMO to identify and respond to any issues that arise, in the most effective way and at the least cost to consumers. An early identification of risks to supply allows AEMO to seek a market response, rather than intervening through the Reliability and Emergency Reserve Trader (RERT), or more disruptive actions such as issuing directions to generators or load shedding.[12]

The NEM is currently in a transitional phase. There has been an emergence of new technologies and some traditional generation plant has been retired. At the same time, the

11 Published September 2017, available on AEMO's website.

12 AEMO may issue directions pursuant to Electricity Law section 116 and Electricity Rules clause 4.8.9.

Electricity Rules are being adapted with urgency to ensure they keep pace with new and changing requirements around the security and reliability of the power system.

It is important for the industry as a whole to be cognisant of this transition and to act to ensure that any associated risks are managed. The AER's view is that there is currently an increased imperative for participants to keep AEMO informed of any events or circumstances that could impact on their plant and/or the power system, even if this requires participants to expand on their current practices for meeting their obligations under the Electricity Law and Rules. We consider it is crucial for all participants and institutions to proactively assist where they can to achieve a successful transition.

The Electricity Rules contain a number of obligations relating to the provision of information to AEMO, and how any changes should be advised. These obligations apply over varying time horizons – from real time to ten years in advance. The ongoing, overarching obligation to ensure all information is up to date is Electricity Rules clause 3.13.2(h), which requires Scheduled Generators, Semi-Scheduled Generators and Market Participants to notify AEMO of any changes to submitted information within the times prescribed in the timetable published by AEMO. As the trading period approaches, there will be greater forecast certainty as to the likely market conditions, plant capabilities and other relevant factors, and under this clause, participants should provide updated data to AEMO.

It is the responsibility of participants to understand their obligations relating to the provision of information in the NEM, many of which can attract civil penalties.[13] We expect participants to have systems and processes in place to ensure they can achieve compliance with these obligations.

Market participants often contact the AER seeking clarification of obligations of the Electricity Rules, including those relating to the provision of information. We encourage such communication and also encourage participants to communicate with AEMO to clarify any aspects of meeting their obligations from an operational point of view when either the Rules or circumstances are unclear. These requests, along with our ongoing monitoring and compliance work may inform future rule change proposals if we conclude that the current arrangements are not sufficient, clear or fit for purpose.

Below we outline our expectations for compliance with a number of individual Electricity Rules obligations and set out some examples of what we consider to be best practice. We strongly encourage participants to adopt these suggestions. Participants should also review their practices in light of this information and to update them as appropriate in readiness for this summer. We have also created a checklist to complement the summer readiness content in the QCR to assist participants with their compliance.

Electricity Rules clause 3.7.3 – ST PASA

The Projected Assessment of System Adequacy (PASA) is the principal method of indicating to AEMO and market participants a forecast of the overall balance of supply and demand for electricity in the NEM. AEMO prepares PASA over two timeframes:

[13] Under section 74 of the Electricity Law, if the AER has reason to believe that a civil penalty provision has been breached, we have the power to issue an infringement notice or institute civil proceedings.

- medium term PASA (MT PASA) covers 24 months from the Sunday after the day of publication with a daily resolution (clause 3.7.2); and

- short term PASA (ST PASA) covers six trading days from the end of the trading day covered by the most recent pre-dispatch schedule with a half-hourly resolution (clause 3.7.3)

This summer readiness messaging focuses on PASA inputs in the short term. AEMO uses ST PASA results to identify lack of reserve (LOR) conditions to inform its decisions about whether market intervention is required to maintain a reliable and secure electricity system. AEMO will seek a market response from participants as a priority where possible, rather than intervening through its safety net mechanisms such as the RERT or more disruptive actions such as issuing directions to generators or load shedding.

We note that the AEMC is presently conducting a rule change process to modify the existing framework for the declaration of LOR conditions, following a request from AEMO. The new framework would replace the current deterministic descriptions of LOR condition levels with a single high-level definition for LOR as well as a requirement for AEMO to make guidelines that set out how it will determine, at least three, LOR conditions taking into account uncertainty of key inputs used in reserve calculations. The current rule change timeline indicates that this rule, if made, would commence on 9 January 2018.

Electricity Rules clause 3.7.3(e) requires a Scheduled Generator or Market Participant to submit the following ST PASA inputs:

- *available capacity* of each *scheduled generating unit*, *scheduled load* or *scheduled network service* for each *trading interval* under expected *market conditions*;

- *PASA Availability* of each *scheduled generating unit*, *scheduled load* or *scheduled network service* for each *trading interval*; and

- projected *daily energy availability* for *energy constrained scheduled generating units* and *energy constrained scheduled loads*.

AEMO uses the available capacity and daily energy availability submitted by participants to determine regional reserve. This process also takes into account 50% probability of exceedance (POE) demand forecasts, LOR trigger levels, and network constraints representing the system under two scenarios (with an intact system and with planned network outages). AEMO's main use for the PASA Availability input in the ST PASA timeframe is to assist it to identify capacity offered by a Scheduled Generator in excess of that offered as available capacity to assist it to determine which units are, or could be, available for direction. AEMO does not use PASA Availability in reserve calculations in the ST PASA timeframe.

The values submitted to AEMO must represent the participant's current intentions and best estimates. Because participants submit these inputs up to six days ahead of time, the AER would expect participants to update their submissions to AEMO taking account of any changes to plant capabilities or other relevant information, to ensure that submitted values remain current intentions and best estimates.

Many participants stated that they conduct daily and weekly team meetings across different areas of the business to discuss weather forecasts, plant availability, and other relevant factors. This forward planning promotes a common understanding of how the plant capability may be affected by the forecast market conditions and whether the ST PASA offers submitted to AEMO should be revised in response. We consider this to be good industry practice and recommend that such communications should be common practice for all businesses.

The ST PASA timeframe starts from the end of the trading day covered by the most recent pre-dispatch schedule, which means there is no overlap between this timeframe and the pre-dispatch timeframe. However, the AER's view of best practice is that participants should continue to update ST PASA inputs during the pre-dispatch period to reflect any relevant changes to these inputs. This will ensure that AEMO has the best information to inform its decisions about market intervention. This approach may also meet other Electricity Rules obligations, such as the requirement to notify AEMO of Scheduled Generator plant changes under clause 4.9.9, as discussed below.

We discuss each of the three ST PASA inputs individually.

Clause 3.7.3(e)(1) – Available capacity

AEMO uses this information in reserve calculations.

Clause 3.7.3(e)(1) states that the available capacity value should be provided "under expected market conditions". In 2010, the Australian Energy Market Commission (AEMC) conducted a rule change for amendments to PASA-related rules.[14] With reference to available capacity provided under this clause, the AEMC's final determination stated *"the term "under expected market conditions" gives sufficient guidance to participants to take weather conditions into account when calculating availability."* This has informed the AER's view of best practice that ambient weather conditions are a relevant factor in the determination of available capacity values.

Participants who responded to our recent compliance review considered available capacity to represent the maximum capacity that the participant could expect a unit to be able to achieve in the relevant period having regard to the expected market conditions. Responses identified a number of ambient conditions that affect the available capacity of a unit, such as air temperature, humidity, wind direction and speed. Equipment that can improve the maximum output capabilities during high ambient temperatures, such as evaporative cooling or fogging, is also a common consideration. The quality of coal was also noted as a major consideration for coal-fired generators.

One participant constructs its available capacity profile considering maintenance, known plant limitations, weather forecasts, current fuel quality and historical availability in similar conditions. Another submits monthly default values on a monthly basis and revises submissions according to major regional load centre forecasts as the trading day approaches. The AER suggests the use of localised weather forecasts rather than the major

[14] The rule change documentation is available on the AEMC's website.

regional load centre, where possible, as they should provide a more accurate representation of the likely conditions at the power station.

These responses show that there are many factors that are influential in determining a generator's available capacity. Participants should have processes and procedures in place to allow an informed view of their assets and provide an accurate and reliable estimate of their capability under the expected market conditions, and to update them as appropriate.

Last summer, AEMO observed intraday rebidding to reduce available capacity over periods of extreme weather due to ambient conditions. We consider that participants should give consideration ahead of time to how market conditions will change across the trading intervals of the day and submit available capacities with a corresponding profile. That is, the sculpted profile would show the greatest degradation of plant capability during periods where ambient conditions are expected to be the most adverse. Submitting values as described may reduce intraday rebidding due to changes in ambient conditions.

Clause 3.7.3(e)(2) – PASA availability

AEMO compares PASA availability to available capacity to help identify additional capacity to inform it of which generating units are or may be available for direction.

Our recent compliance review revealed a common approach to determining the value of PASA Availability for the ST PASA process. A number of participants used available capacity as the basis of the PASA Availability value and add capability that can be made available with 24 hours' notice.

As required by clause 3.7.3(e), PASA availability values are based on current intentions and best estimates, not under a worst case scenario. We consider that the participant's submission should represent what it anticipates will be physically available given the information at hand when the submission is made (regardless of cost). If that information changes, the participant should update the PASA Availability submission.

The AER's view is that this is an indication of a generating unit's physical capability. It is what could be physically available given 24 hours' notice. We note that this does not mean what *would* be available for dispatch, but what could reasonably be available for dispatch.

We also consider that a Scheduled Generator or Market Participant should include capacity in PASA Availability if it has a reasonable expectation that it *could* source fuel (and transport, if applicable) with 24 hours' notice. We understand from participants that where a direction from AEMO is possible (or issued), short term fuel contracts can be more accessible. If there is a reasonable expectation that the fuel could be secured if the participant was under direction from AEMO, then the capacity should be included as PASA Availability. Any risks to attaining this fuel can be communicated to AEMO through the rebid reason field or by direct contact with AEMO's control room. This view is consistent with AEMO's expectations. Amendments to the conditions of a participant's current fuel supply contracts (e.g. gas take-off rates) may also be possible if directed with 24 hours' notice.

However, the AER understands there are examples where there is no possibility or reasonable expectation that fuel will be available in 24 hours (for example, some hydro generators which have no access to additional water). In those instances, the capacity which would require that fuel for operation should not be included in PASA Availability because the fuel supply is not reasonably expected to be replenished or become available with 24 hours' notice.

This approach differs in the MT PASA timeframe because there is a weekly energy constraint which applies to the daily PASA Availability input. PASA Availability in the medium term represents physical capability that can be made available with 24 hours' notice, subject to ambient weather conditions (as outlined in AEMO's guideline), and any fuel limitations would be captured by the weekly energy limits. If participants do not consider their individual situation will be accurately reflected within this framework, they should clarify their MT PASA entry with AEMO to allow AEMO to consider alternative methods of representation.

Clause 3.7.3(e)(4) – Daily energy availability for energy constrained plant

AEMO uses this information in reserve calculations. The ST PASA process prioritises the allocation of fuel-constrained plant to periods of high demand or low generator availability until the energy limit is exhausted.

This obligation applies only to scheduled generating units and scheduled loads that are energy constrained: being those that have fuel to run, but not at maximum capacity across the entire trading day. We remind participants that although fuel limitations have historically been considered most relevant to hydro generators, this is a technology-neutral obligation, and is relevant for other types of generator fuel sources (such as coal, fuel oil and gas). We therefore expect all generators to be mindful of applicable fuel limits and communicate them to AEMO through this process.

Our recent compliance review revealed that participants take a number of factors into account when determining their daily energy limited availability. These factors are specific to generator type but include transportation, on-site storage, refuel rates, quality of coal and gas pipeline linepack. One participant noted that due to its ready access to fuel for a number of its gas-fired generating units, its default bid assumes that its generators are not energy constrained, but it reviews this position if there is an outage in the gas market or any other factor that may cause a delay in the transportation of fuel.

The industry and AEMO's processes are in a period of transition. While AEMO's systems may change in the future, it is our understanding that presently a submission of zero for the ST PASA daily energy limit means that the generating unit is not constrained by fuel. This same interpretation applies where no value is submitted (i.e. a 'null entry'). However, for MT PASA, a zero submission for the weekly energy constraint under clause 3.7.2(d)(2) means that the generating unit is fully constrained, i.e. has no fuel. We encourage participants to review their processes to ensure they are consistent with this approach.

As for other ST PASA inputs, the daily energy availability is based on current intentions and best estimates. Accordingly, we expect participants to base any submissions on what they would reasonably expect to occur given the current information and past experience, rather than a worst case scenario. For example, a gas generator should take planned transport outages into account when determining its daily energy limited availability, but it should not assume that there will be a pipeline issue affecting gas delivery, unless there is information to suggest this is the case.

The AER expects participants to be mindful of any environmental requirements that affect the operation of their plant when determining daily energy availability values.

Clauses 3.8.20(g) and 4.9.8(b) – compliance with dispatch as per pre-dispatch schedule and the latest generation dispatch offer

Clause 3.8.20(g) requires each Scheduled Generator, Scheduled Network Service Provider and Market Customer (who has classified scheduled load) and Market Participant (who has classified an ancillary service generating unit or load) to ensure that it is able to dispatch the relevant plant as required under the pre-dispatch schedule and, if necessary, is responsible for changing inputs via rebidding.

Clause 4.9.8(b) requires a Scheduled Generator to ensure that each of its scheduled generating units is at all times able to comply with the latest generation dispatch offer under Chapter 3 in respect of that generating unit.

The AER has previously outlined our expectations regarding compliance with dispatch instructions through a Compliance Bulletin and following enforcement action taken in relation to clauses 4.9.8(b).[15] The expectations set out below are provided in addition to the previous commentary as they focus on compliance during times of extreme market conditions.

It is important that participants with responsibilities under these obligations have a practice of continually monitoring current output or plant capabilities and comparing those to the pre-dispatch schedule and the relevant dispatch targets from AEMO. Where the current capabilities are unlikely to meet the pre-dispatch schedule or target, the participant should inform AEMO of this through rebids, and if appropriate, by also contacting AEMO's control room directly. We also recommend monitoring actual ambient temperatures and comparing them to the forecasts upon which offers were based, to determine whether offers for the remainder of the day should be updated.

Our recent compliance review revealed a common approach to meeting compliance with clause 4.9.8(b) which we consider to be good practice. Some participants stated that they have automatic systems to track actual output and compare this to the current dispatch target, and an alarm will activate if output is not meeting target. The alarm would induce the plant operator or trader to investigate further and, if necessary, to submit a rebid to AEMO. This may be an effective way of achieving compliance with this obligation.

During extreme weather conditions, when the plant may be more likely to derate, participants should ensure that there is clear and frequent communication between operations and trading staff. As noted by many respondents to our recent compliance review, the capability of generators may not change in a linear or predictable manner in response to changes in ambient conditions. Participants also noted that it is not common to operate plant at full capacity for extended periods, as was required on occasion last summer, and the capability

15 Compliance Bulletin No. 1 is available on the AER's website.

of units under those conditions can be unknown. Because of these issues, it is increasingly important for plant operators to monitor real-time generator output against targets and communicate any changes in capability due to ambient conditions to traders. Traders should then provide updated information to AEMO about current plant capabilities.

Clause 4.9.8(d) – compliance with the latest market ancillary service offer

For providers of ancillary services, clause 4.9.8(d) requires a Market Participant which has classified a generating unit or load as an ancillary service generating unit or an ancillary service load, as the case may be, to ensure that the ancillary service generating unit or ancillary service load is at all times able to comply with the latest market ancillary service offer for the relevant trading interval.

There are two types of frequency control ancillary services (FCAS): contingency and regulation FCAS. As a general principle, it is important that contingency FCAS services are delivered when required as they form a key part of the safety net measures to ensure power system security is maintained. It is important that Market Participants offering contingency FCAS services appropriately test their equipment and perform due diligence to ensure they are capable of meeting AEMO's Market Ancillary Services Specification when their offer is called upon. With respect to contingency FCAS services, generators are paid to be available *if needed*. Given that the requirement to actually deliver is relatively infrequent, generators could receive large payments for a service they may have never been able to provide, which is only then apparent when not delivered. There are limited opportunities to discover plant issues other than through actual events, unless the generator carries out due diligence and/or appropriate testing. This may mean that in addition to reviewing actual responses following an event, it may be necessary for generators to test individual elements of control systems or processes in isolation to provide a reasonable level of assurance that the overall response is likely to perform effectively when required.

Furthermore, if Market Participants who provide market ancillary services are making changes to plant, we expect them to be cognisant of any implications these changes will have on their ability to provide the services for which they have committed to provide. These participants should carry out due diligence when dealing with the Original Equipment Manufacturer to ensure that new plant, or plant changes, has undergone appropriate testing against the Australian Standards (noting that these may not be the default settings for the plant).

The AER expects that part of the generator's obligations for due diligence of testing and monitoring equipment, especially with respect to complying with clause 4.9.8(d), would be to monitor performance and self-report issues to the AER in a timely manner.

For example, clause 3.11.2(i) states that AEMO may from time to time require a Registered Participant which provides a market ancillary service to demonstrate the relevant plant's capability to provide the market ancillary service to the satisfaction of AEMO according to standard test procedures. A Registered Participant must promptly comply with a request by AEMO under this clause. This is an area that the AER may consider for a future targeted compliance review.

Clauses 3.11.2(f) and (h) – Market ancillary services

Clause 3.11.2(f) requires a Market Participant which has classified a generating unit as an ancillary service generating unit or a load as an ancillary service load to install and maintain, in accordance with standards developed by AEMO, monitoring equipment to monitor and record the response of the relevant unit or load to changes in the frequency of the power system. Under clause 3.11.2(h), AEMO may request a report on how the relevant facility responded to a particular change in the frequency of the power system, and the Market Participant must provide this report promptly, but no more than 20 business days after AEMO's request.

Market Participants must have functioning data systems in place to ensure they capture relevant ancillary service data and are able to provide this data to AEMO on request. We encourage all providers of these services to audit their data systems ahead of summer to confirm that it captures the required data and could provide to AEMO if requested. Market Participants should also ensure that the data system's storage capacity is adequate to capture the required information, and increase this if it is insufficient.

As mentioned in the area for 4.9.8(d), the ability for Market Participants to comply with their market ancillary services' offer, should be supported by their own testing and compliance programs. While clauses 3.11.2(f) and 3.11.2(h) are not civil penalty provisions, the AER considers it important that this information is available to AEMO for its analysis and planning. These are also obligations that the AER may consider for a future targeted compliance review.

Clause 4.8.1 – advising AEMO of threats to the secure operation of the power system

This obligation requires a Registered Participant to promptly advise AEMO at the time it becomes aware of circumstances which could be expected to adversely affect the secure operation of the power system or any equipment owned or under the control of the Registered Participant or a Network Service Provider.

We note that this obligation applies to all Registered Participants, which includes all classes of generators, as well as Network Service Providers and (market) Customers. Compliance with this obligation is critical to the secure operation of the market, as it ensures that AEMO can respond to any threats to system security in a timely and appropriate manner.

While a participant may not know the full extent to which power system security may be impacted by an event, it is important that any risks are promptly communicated to AEMO so it may form a comprehensive understanding of any potential impacts on the power system.

During the extreme weather events last summer, we observed generators rebidding to reduce the available capacity of their units in efforts to protect them from an identified risk of trip. Reducing generation can be an effective way for generators to manage such risk. However we remind generators that they should also contact AEMO to notify it of the risk at the earliest possible time. This will assist AEMO to carry out any required contingency planning to respond to the possibility of the risk being realised.

Clause 4.9.9 – Scheduled Generator plant changes

Clause 4.9.9 requires a Scheduled Generator to notify AEMO of any event which has changed, or is likely to change, the operational availability of any of its scheduled generating units, whether synchronised or not, as soon as it becomes aware of the event.

This obligation requires Scheduled Generators to notify AEMO of changes in operational availability whether the unit is synchronised or not. Updating the operational availability of plant that is not synchronised is important as this plant may still be dispatchable, or directed to generate.

This clause places a positive obligation on the participant to notify AEMO of changes. While we understand that AEMO's control room may contact participants seeking additional real time plant availability information, participants should not rely on such contact as a means of meeting the requirements of the clause.

Our recent compliance review asked generators how they meet compliance with this obligation. One hydro generator outlined that it had an automated system to actively monitor influential factors such as forecast water inflows, dam levels and ambient conditions and provide AEMO with updates to relevant information in real time.

The AER's view of best practice is similar to practices described by some participants. It comprises different approaches to notifying AEMO, depending on whether the event has changed the operational availability of a generating unit, or whether there is a future likelihood that the operational availability will change. We consider that this approach may also achieve compliance with other obligations, such as clauses 3.7.3(e) and 4.9.8.

- If the event has changed the operational availability of the scheduled generating unit, a Scheduled Generator should submit rebids to AEMO updating its offers, ST PASA, MT PASA or fuel constraint parameters (if appropriate) to reflect the revised capability of the unit.

  We consider that updating ST PASA inputs during the pre-dispatch period in response to changes in operational availability may be a way to achieve compliance with clause 4.9.9 (and 3.13.2(h)). Doing so will convey the most accurate unit capabilities over the current day to AEMO and allow AEMO to perform its intraday reserve calculations with current plant capabilities.

- If the event is likely to change the operational availability of the scheduled generating unit in the future, for example if the event has increased the risk of a unit trip, the Scheduled Generator should inform AEMO's control room immediately. There should be no update to generator availability information through updates to offers or ST PASA parameters, as there has not been an actual change in the unit's capability.

Where the event has implications (realised or potential) for the operational availability of a generating unit on an ongoing basis, such as a long term outage or impairment of a unit, the Scheduled Generator should discuss this with AEMO. This will achieve a common understanding of the issue and the implications of any subsequent events including mitigating actions.

Clause 4.9.2(d) – Personnel to receive and immediately act upon dispatch instructions

This obligation requires a Scheduled Generator or Semi-Scheduled Generator, with respect to its generating units that have an availability offer of greater than 0 MW (whether synchronised or not), to ensure that appropriate personnel are available at all times to receive, and immediately act upon, dispatch instructions issued it by AEMO.

We note that the obligation applies 'at all times' and we expect generators to have sufficient resources available to control and direct generating units to meet dispatch instructions; this is particularly important during a system security event, which can occur at any time, requiring increased communication with AEMO. While generation assets may be operated by third parties under contract, this obligation falls on the Registered Participant for the asset and it is the responsibility of the Registered Participant to ensure that its agreements with such third parties support compliance with it.

We understand that personnel may be responsible for controlling numerous generation units at any time. Businesses need to assess whether additional equipment or staff are required to effectively manage the fleet during extreme market events where there may be an increased number of simultaneous changes or increased monitoring. We consider it good industry practice for generators to have contingency plans in place, whereby additional personnel may be called upon at short notice to assist with operations during extreme market events.

There should also be effective communication between various personnel (for example, between plant operators and trading staff) so that the roles and responsibilities for operating equipment in response to AEMO's dispatch instructions are clear. Furthermore, the AER considers that all calls between traders and AEMO's control room should be recorded as best practice, irrespective of the time of day.

Clauses 3.8.17, 3.8.18, 4.9.6(a) and 4.9.7(a) – Informing AEMO of self-commitment and self-decommitment decisions

Clauses 3.8.17, 3.8.18, 4.9.6 and 4.9.7 outline how and when a Scheduled Generator should inform AEMO of its intentions for self-commitment and self-decommitment of a scheduled generating unit. Under clauses 3.8.17 and 3.8.18, a Scheduled Generator greater than 30 MW must advise AEMO of its intentions to self-commit and synchronise or self-decommit and de-synchronise through PASA and pre-dispatch by submitting an amended available capacity profile. The generator must inform AEMO of any changes to self-commitment self-decommitment decisions without delay.

Clauses 4.9.6(a)(1) and 4.9.7(a) further outline that for self-commitment and self-decommitment, the Scheduled Generator must confirm with AEMO the expected synchronising/de-synchronising time with at least one hour's notice, and update this advice five minutes before synchronising/de-synchronising, unless otherwise agreed with AEMO. In addition, for self-decommitment, clause 4.9.7(b) states that the Scheduled Generator must not de-commit a generating unit unless it has confirmed with AEMO a number of details relating to that de-commitment.

It is essential that Scheduled Generators provide (at least) the required one hour notice of self-commitment and self-decommitment to AEMO to ensure that AEMO can maintain system security.[16] There are a number of system security requirements that AEMO must meet, such as the requirement in South Australia for a minimum of three synchronous generating units to be online at all times. Providing AEMO with the required notice, particularly for self-decommitment, avoids situations where AEMO must direct other generators to synchronise at short notice to meet system security requirements.

Clause 4.15 – Compliance with generator performance standards

Generators are required to implement and maintain specific compliance programs in accordance with clause 4.15 of the Electricity Rules. Compliance with performance standards is fundamental to ensure AEMO can safely and reliably operate the power system. Non-compliance with certain performance standards may materially increase the risk of major power system incidents.

Clause 4.15(f) requires generators to immediately notify AEMO of any breaches or likely breaches of a performance standard. This is done by completing and submitting to AEMO a *Notice of Non-compliance with Registered Performance Standards*.[17] This immediate notification allows AEMO to assess the implications of the non-compliance on the power system and, where necessary, take actions to ensure power system security can be maintained.

During extreme weather events or times of high demand, when the power system is running near or at full capacity, any reductions in generator performance can lead to cascading failures in the market. While the obligations regarding generator performance standards are ongoing, participants should ensure compliance arrangements are fully effective as we approach summer.

As part our recent compliance review, one participant outlined that it was prompted by the market events of last summer to conduct a review of its compliance with generator performance standards under clause 4.15. It has updated its compliance programs and documentation to ensure they are up to date. The participant has also reviewed its testing requirements and is prioritising testing ahead of this summer to avoid inflexible outages due to plant issues. We alert other participants to this level of diligence.

AEMO summer readiness

AEMO held an event in Melbourne on 1 December 2017 where it will present its summer readiness plan to industry, alongside presentations from other organisations. AEMO's summer readiness plan focusses on maximising resources in the system to meet peak demand this summer, including:

- Generation availability – working with generators to improve availability when required and to improve availability information.

16 Under Electricity Rules clause 3.8.18(b), 2 days' notice is required for planned self-decommitment of slow start generating units.

17 Available on AEMO's website.

- Fuel availability – working with generators and producers to confirm sufficient fuel for synchronous generators is available ahead of when required (i.e. coal, gas and water).
- Transmission network availability and capacity – working with industry to ensure maintenance is conducted outside the peak period.
- Contingency planning – identifying opportunities to strengthen the network and carrying out national planning exercises to ensure mitigation strategies are clear across industry.
- Training and communication – working with governments and industry to clearly communicate protocols and procedures for times of potential risk to the power system.
- Working with the South Australian government and industry to implement the government's SA Energy Plan.
- Procuring additional reserves for this summer through the RERT provisions, including emergency generation and demand side participation.

2.2 High Price Events

The AER must publish a report whenever the spot price for electricity exceeds $5000 per megawatt hour (MWh) and whenever the ancillary service price exceeds $5000 per megawatt for a sustained period[18]. These reports are available on our website[19].

2.2.1 Reports published since 1 July 2017

Since 1 July 2017, we have reported on the following extreme price events from the 2016/17 summer period. Each event involved sustained ancillary service prices in excess of $5000 per megawatt, namely high prices in Frequency Control Ancillary Services (FCAS) markets.

Figure 4: Reports published since 1 July 2017

	Event Date	High Price Period	Region	Market	Highest Price
1	9/11/2016	04:30 - 18:30	SA	FCAS	7 334
2	25/11/2016	04:30 - 11:30	SA	FCAS	11 014
3	23/01/2017	5:30 - 6:00	SA	FCAS	9 333
4	21/03/2017	11:30 – 16:30	SA	FCAS	11 982
5	30/03/2017	9:30 – 13:30	SA	FCAS	11 608
6	18/04/2017	12:30 – 18:30	SA	FCAS	14 000

18 Under 3.13.7(d) of the Electricity Rules the AER must publish its report within 40 business days of the end of the week in which the spot price exceeded $5000/MWh in a trading interval or trading intervals. Whilst the AER must also publish a report whenever the ancillary service price exceeds $5000 per megawatt, there is no legislated timing on the publication of the ancillary service reports. However, we do endeavour to conduct our investigations as expeditiously as possible.

19 http://www.aer.gov.au/wholesale-markets/market-performance

7	22/05/2017	12:30, 13:00, 18:00, 18:30	SA	FCAS	10 770
8	28/08/2017	10:30 – 19:00	SA	FCAS	11 602
9	14/09/2017	9:00 – 16:30	SA	FCAS	11 509

2.2.2 Reports pending

Currently, we are preparing reports in relation to high price events in ancillary service markets on the following days.

Figure 5: Reports to be published

	Event Date	High Price Period	Region	Market	Highest Price
1	13/10/2017	7:30 – 13:30	SA	FCAS	10 700
2	14/10/2017	6:30 – 9:00	SA	FCAS	9 500
3	24/10/2017	19:00 – 20:30	SA	FCAS	13 272

The AER endeavours to publish its $5000 per megawatt hour reports for electricity in a timely manner and in accordance with timeframes required by the Electricity Rules. We sometimes make full use of these timeframes to ensure that these reports are accurate, comprehensive and reflective of consultations with market participants.

2.3 Commencement of 'Power of Choice' Rule Changes on 1 December 2017

Under the 'Power of Choice' rule changes, metering contestability commences in the Australian Capital Territory, New South Wales, Queensland, Tasmania and South Australia from 1 December 2017. The arrangements in Victoria, which is not implementing metering contestability at this point, are discussed below under '2.5 Jurisdictional Derogations'. This QCR focuses on the new market arrangements, to assist in a smooth transition to both metering contestability and enhanced retail competition within embedded networks.

2.3.1 Metering forums

During September, the AER held two industry forums on metering contestability focusing on the requirements on industry under the new 'Power of Choice' metering contestability provisions that commence in the Australian Capital Territory, New South Wales, Queensland, Tasmania and South Australia from 1 December 2017. The forums were held in Melbourne (25 September 2017) and Sydney (27 September 2017). At both forums, AER staff presented on both the new requirements and the AER's approach to compliance and enforcement under the National Energy Retail Law and Rules and the National Electricity Law and Rules. This was followed by a presentation from AEMO, focusing on commencement of the new market arrangements, and an update on the registration and accreditation processes for Metering Coordinators. The market bodies' sessions were followed by a session presented by an incumbent market participant. The final session at each forum was delivered by parties seeking registration as a Metering Coordinator. Participants in the forums worked through a range of implementation scenarios and queries, with detailed discussion of a range of compliance issues, including outage notifications, aged asset replacements and site access.

2.3.2 Staged approach to metering contestability

To mitigate the risks associated with metering contestability commencing during the peak period for new connections, industry participants have agreed to a staged approach to the transition to metering contestability. This approach was agreed at the Power of Choice Executive Forum meeting convened by AEMO on 28 August 2017, where the majority of industry participants polled agreed to a staged transition model for the commencement of meter contestability in relevant jurisdictions.

The staged transition model, which is optional, allows for distributors to provide new connection services for a transitional period from 1 December. The staged transition concludes on 30 March 2018. During the transitional period, retailers that have 'opted-in' can utilise the services of the Local Network Service Provider (LNSP) to perform new metering services with type 5 and type 6 metering installations for new connections and 'additions and alterations'. The services must have been accepted as service requests by the LNSP by 30 November 2017. In New South Wales, accredited service providers will provide the relevant services for requests received by that date. Any new connection service orders and 'Additions and Alterations' service orders that are not completed by 30 March 2018 will not be performed by the LNSP. Retailers will need to arrange with a competitive Metering Coordinator to provide those services for affected sites.

In September 2017, the AER provided a letter of no action to support the staged approach. This letter of no action was provided to the Energy Networks Association on behalf of electricity distributors in the ACT, New South Wales, Queensland, Tasmania and South Australia. This allows for LNSPs named in the letter to deploy type 5 and type 6 metering installations from 1 December. The deployment of these meters would otherwise be in breach of the Electricity Rules requirement for all new and replacement meters for small customers to be smart meters.

2.3.3 National Electricity Rules: transitional period with respect to requirement for embedded network operators to become or appoint an Embedded Network Manager

From 1 December 2017, persons that hold a network exemption in relation to an embedded network must appoint or become an Embedded Network Manager. The Embedded Network Manager is a new accredited service provider that has been created to facilitate customers in embedded networks moving between off-market and on-market retailers. The requirement to appoint an Embedded Network Manager in accordance with clause 2.5.1(d1) of the National Electricity Rules[20] applies unless:

- The embedded network is located in a state, territory or region where customers in embedded networks are not afforded a right to a choice of retailer; or
- The AER has determined that the requirement can be delayed until a customer in the embedded network enters into a contract with a market retailer.

The AER's Network Service Provider Registration Exemption Guideline provides that holders of all network exemption classes may delay appointment unless the embedded network contains 30 customers or more relating to the network exemption classes: ND10, NR1, NR2, NR3, NR5 and NR6.[21]

The Embedded Network Manager role involves:

- registering a child NMI (National Metering Identifier) to customers in embedded networks so they can be identified in the market
- creating and updating NMI standing data (which includes identification of the market retailer, the type of meter used and other information but does not include meter reading data).

Previously, there has been no party formally responsible under the National Electricity Rules for providing this service for customers in embedded networks. However, retailers and distribution businesses have provided this function for embedded network customers in the past.

To allow an opportunity for embedded network operators to adjust to the new requirement to become or to appoint an Embedded Network Manager, the AER will allow an initial transitional period from 1 December 2017 to 31 March 2018. Where an embedded network operator can demonstrate they are taking active steps to appoint an Embedded Network Manager, the AER will focus on education and not actively pursue enforcement of compliance issues in respect to the NER requirement.

During this transitional period, we will assess any compliance matters that come to us on a case-by-case basis and in a manner that acknowledges the restrictions that Embedded Network Manager accreditation issues may have placed on embedded network operators' capacity to comply with their obligations. However, we will expect to be provided with evidence that parties have attempted to secure an Embedded Network Manager and have been unsuccessful or are currently engaged in the process of securing an Embedded Network Manager.

We will encourage a gradual movement towards compliance for all stakeholders during this transitional period through our approach to compliance matters that come to our attention.

20 The reference to clause 2.5.1(d1) is to the provision as it applies from 1 December 2017, following commencement of the *National Electricity Amendment (Embedded Networks) Rule 2015.*

21 Network exemption holders can use the AER's interactive web based decision tool to assist them in determining whether an embedded network manager is required for their network: provide link to the web tool.

The AER reserves the right to undertake further action in relation to compliance issues for which the network exemption holder cannot demonstrate that they have taken steps to come into compliance with the requirement to appoint an Embedded Network Manager.

2.3.4 Commencement of Distribution Ring Fencing Guidelines from 1 January 2018

On 30 November 2016, the AER issued the Ring-fencing Guideline (Electricity Distribution), as required under the new metering rules. The distribution ring-fencing guideline will apply across the National Electricity Market. This guideline sets out a robust and well-targeted set of obligations that distribution businesses must comply with to separate their regulated distribution services from the unregulated services, which must be either functionally separated or offer by a legally separated affiliate entity. The distribution ring-fencing guideline took effect from 1 December 2016, and distribution network service providers (DNSPs) are required to comply with the guideline as soon as it is reasonably practicable and no later than 1 January 2018, subject to any waivers. The AER released a Draft Decision on waiver applications from DNSPs under the Ring-fencing Guideline in October and will publish a final Decision in December 2017, taking into account any submissions we receive. Submissions were due on 13 November 2017.

DNSPs are required to report on ring-fencing compliance for the first regulatory year that commenced after the Guideline took effect on 1 December 2016. DNSPs must submit an annual compliance report to the AER within four months of the end of the regulatory year to which the compliance report relates. Victorian DNSPs will submit their first annual compliance report, along with an assessment of compliance by a suitably qualified independent authority, by 30 April 2018. All other DNSPs will submit their first annual compliance report and accompanying independent assessment by 31 October 2018.

2.3.5 Transition of the Responsible Person role and provision of meter-related information to Metering Coordinators from 1 December 2017

To assist in enabling a smooth transition to metering contestability in the ACT, New South Wales, Queensland, Tasmania and South Australia from 1 December 2017, the AER and AEMO have jointly developed the following guidance to incoming Metering Coordinators and outgoing Responsible Persons:

1. Newly appointed Metering Coordinators are to ensure that the metering installation they are appointed for is compliant with the Electricity Rules and related procedures.

2. Prior to appointing Metering Coordinators from 1 December 2017, retailers are to seek full disclosure of metering installation compliance status from the former Responsible Person (where the retailer did not perform that role):

    a. For type 1 - 4 metering installations, compliance status is to be confirmed for each individual metering installation

   b. For type 5 and 6 metering installations, retailers are to obtain details of current metering installation malfunction exemptions, to confirm any family failures under a current or pending replacement program. These details should include all affected National Metering Identifiers.

3. Outgoing Responsible Persons are expected to provide full disclosure of metering installation compliance status in accordance with points 2(a) and (b) above. This information is to be provided to the retailer as the Financially Responsible Market Participant.

4. Metering Coordinators are to seek full disclosure of metering installation compliance status from their appointing retailer, including:

   a. Family failure replacements requiring a new rectification plan (and potential exemption) from 1 December 2017.

   b. Device certification expiry dates and previous test method for type 1-4 meters and related instrument transformers (noting that the certification of compliance given to Responsible Persons undertaking AEMO's alternate methodology expires 30 June 2018, irrespective of when the testing was completed).

   c. Identification of metering installations where energy volumes exceed jurisdictional volume thresholds.

5. Metering Coordinators are to contact AEMO's metering team to validate that any failure notified to them via the outgoing Responsible Person or via the retailer that is financially responsible for the site is supported by a malfunction exemption or the equivalent in a recently updated asset management plan, and that in the case of notification of a family failure, that the failure was identified as a result of testing to an asset management strategy approved by AEMO.

6. Where the Responsible Person has failed to provide this information to the relevant retailer, or where AEMO is unable to validate, the AER may undertake inquiries to determine whether the failure to provide this information is due to pre-existing compliance issues.

Incoming Metering Coordinators that have concerns in relation to the adequacy of the disclosures they have received from the outgoing Responsible Person or their appointing retailer may raise these concerns with the AER.

2.4 Review of Responsible Person compliance with metering upgrade obligations under Chapter 7 of the National Electricity Rules

2.4.1 Targeted Compliance Review: Stage 1

During 2017, the AER's priorities include focussing on participant readiness for metering contestability and related changes under the Power of Choice rule changes. In our March

Quarterly Compliance Report (QCR), we stated that the AER will be paying particular attention to compliance with obligations in Chapter 7 of the Electricity Rules, both in the lead up to the Power of Choice changes and following implementation of those changes.

In our March 2017 Quarterly Compliance Review, we reported on the first stage of a targeted compliance review of Responsible Person obligations to upgrade customer metering installations where the customer's consumption increases and a new metering installation is required. This review was initiated by the AER due to a substantial increase in recent years in the number of second tier meters that exceed jurisdictional volume thresholds for manually read meters. The first stage of the review examined the practices of Local Network Service Providers (LNSPs). The second stage of the review, which was undertaken during the September quarter, examined Financially Responsible Market Participants' compliance with their obligations to upgrade customer metering installations where the customer's consumption increases such that a new metering installation is required.

2.4.2 Targeted Compliance Review: Stage 2

Clause 7.2.5(d) of Electricity Rules (as they apply at 30 November 2017)[22] requires the Responsible Person to ensure that the metering installation is provided, installed and maintained in accordance with the rules, the metrology procedure, and procedures authorised under the rules. The responsibility for upgrading metering installations therefore rests with the Responsible Person. Clause 7.2.5(d) is a civil penalty provision, which means it is a provision the breach of which can attract a monetary penalty under the legislation. Clause 7.3.4(a), which is also a civil penalty provision, provides that the type of metering installation and the accuracy requirements for a metering installation which must be installed in respect of each connection point are to be determined in accordance with Schedule 7.2. Schedule 7.2 sets out the minimum requirements for metering installations, including the relevant volume limit per annum per connection point, and the accuracy standard. For type 5 and type 6 metering installations, volume limits per annum are specified in the Metrology Procedure.

Clause 7.2.2 of the Electricity Rules provides that a Financially Responsible Market Participant (FRMP) may elect to be responsible for a type 1, 2, 3 or 4 metering installation, and is the Responsible Person for these metering installation types if they elect not to request an offer from, or do not accept the offer of the Local Network Service Provider (LNSP). A key issue identified in the first stage of the targeted compliance review is that this provision does not set any time limits on the Financially Responsible Market Participant in relation to either electing not to request an offer from an LSNP, or declining the offer of the LNSP.

For the second stage of the targeted compliance review, we reviewed monthly reports prepared by AEMO to understand Financially Responsible Market Participants' compliance status in relation to the obligation to upgrade metering installations in accordance with Chapter 7 of the Electricity Rules and related procedures. We focussed on Financially Responsible Market Participants which had a significant number of metering installations where the consumption levels indicate that the meter type installed at the connection point

22 References to provisions in Chapter 7 of the Electricity Rules are to the provisions as they apply at 30 November 2017, before the "Power of Choice" rule changes take effect on 1 December 2017.

may be incorrect. We also confirmed with AEMO that relevant entities have been receiving notifications from AEMO regarding the affected metering installations, but had failed to rectify the issues, often over an extensive period of time. While the initial focus was on seven retailers, additional retailers may be subject to a review by the AER in the future if AEMO's reports indicate any deterioration with respect to their performance in this area.

We requested relevant businesses to provide information in relation to the processes, systems and procedures they have in place to achieve compliance with requirements on the Responsible Person to upgrade customer metering installations where the customer's consumption increases and a new metering installation is required. As part of this review, we were particularly interested in understanding the processes that relevant businesses adopt in terms of assuming responsibility to upgrade metering installations. This includes communications with relevant parties, including LNSPs, customers and AEMO, and processes for initiating a transfer of the Responsible Person role in the Market Settlement and Transfer Solution (MSATS) system.

2.4.3 Review of retailer's responses

Overall, retailers indicated that they had improved their systems and processes to initiate and facilitate metering upgrades as required under the Electricity Rules and related procedures, including initiating a transfer of the Responsible Person role to themselves in the MSATS system. Retailers indicated that they either rarely or never received an offer from the LNSP to upgrade the meter. They suggested that delays in completing upgrades at the required sites are largely due to difficulties obtaining customer agreement.

The key difficulties that retailers advised they encountered in attempting to arrange a meter upgrade were:

- Inability to contact the customer from available contact details
- Customer reluctance to consent to a large customer contract (where a meter upgrade as well as a new retail contract is required following reclassification of a 'small' customer to 'large')
- The site may require current transformer (CT) metering and therefore the customer needs to engage an electrician
- Customers' reluctant to bear the costs associated with a metering upgrade such as rewiring costs, and unbundled meter charges
- Customers' lack of understanding of metrology requirements
- Site access refusal issues

Retailers' responses suggest that most delays are related to customers' understanding of the requirement and agreeing to schedule and provide timely access to sites that require metering upgrade work. While we acknowledge that a level of customer cooperation is required to achieve a metering upgrade, the wide variation in performance across retailers suggests that customer cooperation is not the only factor affecting compliance. A number of retailer responses provided copies of standard form correspondence that is sent to customers that require a meter upgrade. There was considerable variation in retailers' approach to this correspondence, in particular on matters such as advising customers of the possibility of disconnection for failure to provide site access for a required meter upgrade, and advising customers of the safety issues associated with using a meter that is inappropriate for their consumption.

Given that from 1 December 2017, new and replacement meters for small customers will be type 4 metering installations, it is inappropriate for retailers to allow large customers to continue to refuse a meter upgrade to a type 4 meter. Over time, we expect that the requirement for new and replacement metering to be a type 4 metering installation will lead to a reduction in the number of meters being reported by AEMO as requiring an upgrade. We expect that retailers should continue to improve their processes for co-ordinating with customers on metering upgrades, and should give priority in their smart meter roll-outs to customers with higher consumption.

To ensure that affected metering installations are being upgraded in accordance with the requirements of Chapter 7 of the Electricity Rules, the AER will be seeking further reports post December 2017 on metering installations that continue to exceed jurisdictional volume thresholds. If retailer performance in this area does not improve sufficiently, the AER may seek the introduction of timing requirements for meter upgrades.

2.5 Jurisdictional Derogations – Metering Contestability

The Victorian Government has decided to defer the introduction of metering competition in Victoria until at least 2021.

On 10 October 2017, a Ministerial Order was made under the *National Electricity (Victoria) Act 2005* to modify the application of the Electricity Rules governing metering so that existing Victorian metering arrangements may continue. The Order defers the introduction of metering competition in Victoria, and allows for distributors to continue as the exclusive providers of metering services to new and existing small customers connected to their networks (that is, customers with annual electricity consumption of less than 160 MWh).

On 11 October 2017, an Order in Council was also made under the *Electricity Industry Act 2000* (Vic) to regulate the ongoing installation, operation and maintenance of smart meters in Victoria. This Order ensures that the minimum specification for small customer metering in Victoria is the Victorian specification for metering, rather than the national specification for metering. Only distributors will be able to operate in the role of Metering Coordinator in Victoria for small customers connected or proposing to connect to their distribution networks.

Customers in embedded networks in Victoria that exercise choice of retailer will need their retailer to appoint a Metering Coordinator under Chapter 7 of the Electricity Rules in order to access the competitive market from 1 December 2017. While distributors will be the initial Metering Coordinator for type 5 and type 6 metering installations in Victoria for on-market children connected to embedded networks, these arrangements will cease no later than 1 December 2018. Retailers will be responsible for appointing a Metering Coordinator under Chapter 7 of the Electricity Rules and the Metering Coordinator will be responsible for ensuring that the metering installation complies with Chapter 7. Retailers servicing on-market embedded network customers in Victoria will need to ensure that they appoint a competitive Metering Coordinator for Victorian on-market embedded network customers by no later than 1 December 2018.

2.6 Instrument Transformer Testing

Clause 7.2.5(d)(2) of the Electricity Rules (as they apply at 30 November 2017)[23] requires that the Responsible Person (RP) ensures the components[24] (including current transformers and voltage transformers), accuracy and testing of each of its metering installations complies with the requirements of the Electricity Rules and the metrology procedures authorised under the Electricity Rules. Rule 7.2.5(d) is a civil penalty provision. From 1 December 2017, this obligation will transfer to Metering Coordinators under clause 7.3.2(e)(2) of the Electricity Rules. AER expectations regarding this transfer are addressed in section 2.3.5 above.

Schedule 7.3.1 of the Electricity Rules requires the RP to test current transformers (CTs) and voltage transformers (or instrument transformers) for accuracy every 10 years (unless an alternate test plan has been approved by AEMO). Instrument transformers are designed to lower voltages or current in the high voltage transmission and distribution network to levels for use by metering devices. Inaccurate instrument transformers can affect the overall accuracy of the metering installation.

In 2011, the AER became aware that low voltage (LV) CTs were not being tested in accordance with the Electricity Rules. In response, we published a compliance bulletin containing our expectations in relation to LV CT testing.[25] Specifically, the bulletin proposed that an RP should test either 10 per cent of its LV CT connected metering installations each year, or a sample of its LV CT connected metering installations in accordance with an alternative sampling method approved by AEMO. Subsequently, RPs submitted their test strategy to AEMO, with the initial round of testing to be completed within 12 months from 1 July 2012. In mid-2015, we commenced another review of compliance with testing obligations, starting with the RPs undertaking the alternative sampling method. In April 2017, the last RP adopting the alternative sampling method completed the required testing.

During this quarter (July to September 2017) we focused on those RPs who elected to test 10 per cent of their population each year. The responses we received for this part of the review indicate that most RPs have made significant progress with testing ten percent of their population each year since 2012. However, some RPs have failed to complete all the required tests from previous financial years and were still required to complete a significant number of tests prior to December 2017. We are particularly concerned about ActewAGL Retail and TasNetworks which still have a significant number of sites to test in order to achieve compliance.

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23 References to provisions in Chapter 7 of the Electricity Rules are to the provisions as they apply at 30 November 2017, before the “Power of Choice” rule changes take effect on 1 December 2017.

24 Metering installation components are defined by Rule 7.3.1 of the Electricity Rules.

25 The compliance bulletin can be found here. This bulletin will be reviewed once the AER has had sufficient experience of metering contestability to determine whether a revised bulletin is required.

This review indicates that a common challenge for RPs in this process has been that some customers are not allowing site access for the RP to conduct the required testing, as testing requires a full outage at the site. While we understand that customers' co-operation is required in order to obtain access and complete the required tests at relevant sites, the wide variation in performance across RPs suggests that that other factors affect compliance. A number of RPs have successfully managed this issue by contacting in advance more customers than are required to be tested. By allowing for some access issues, these RPs have been able to test the required number of sites.

Our 2017 review also indicates that some businesses can improve their processes and systems in terms of record keeping to ensure they are completing their tests of all family types within the required timeframe. Some businesses inadvertently exceeded the ten percent testing requirement or fell below it as a result, in some instances, of poor record keeping. Since our expectation set out in section 2.3.5 above is that all RPs will pass on information on the compliance status of metering installations to incoming Metering Coordinators, we expect all outgoing RPs to use their best endeavours to ensure that Metering Coordinators receive comprehensive and up-to-date information for sites that they are responsible for.

2.7 Generator Rebidding

Scheduled generators and market participants operating in the National Electricity Market (NEM) submit offers and bids for each half hour trading interval. The offers and bids include available capacity for up to 10 price bands and can be varied through rebidding.[26]

According to the 'three stage process' introduced in late 2010 and updated in 2012,[27] we will consider issuing an infringement notice if we issue three notifications within a six month period to generators who submit offer, bid and/or rebid information that does not meet the requirements of the Electricity Rules. The warning count for a participant is set to zero after six months of the first warning being issued.

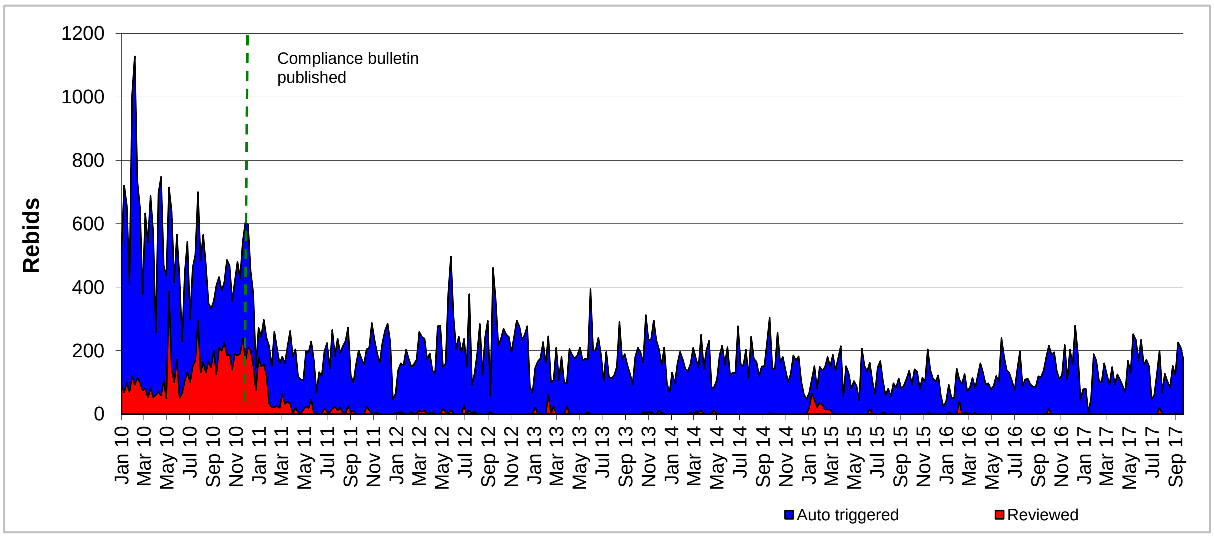
Frequent submission of offers, bids and rebids which do not meet the relevant requirements of the Electricity Rules can seriously and adversely impact the NEM. In particular, the quality of information available to relevant participants and other persons is reduced, which in turn reduces market efficiency. Poor quality information also affects the AER's ability to monitor and enforce compliance with the Electricity Rules.

As shown below in **Figure 6**, the number of rebids automatically triggered as requiring initial examination (indicated by the blue area) has fallen markedly since 2011.

26 Market participants must provide to AEMO, at the same time as a rebid is made, a brief, verifiable and specific reason for the rebid, plus the time at which the reason for the rebid occurred. Equivalent requirements apply where AEMO is advised, under clause 3.8.19 of the Electricity Rules, that a unit, service or load is inflexible. Clause 3.8.22A of the Electricity Rules requires that dispatch offers, dispatch bids and rebids are made in 'good faith'.

27 In June 2012, we published an updated Compliance Bulletin No. 3 to make it clear that, for the purposes of administering the three stage process and issuing warnings, we will rely on the cumulative count of non-compliant bids for all generating units under the same portfolio. In other words, where a parent company employs a common trading team for the bidding of multiple generating units in its portfolio, irrespective of whether these generators are different registered participants, we will count any non-compliant bids by that trading team together.

Figure 6: Rebids auto-triggered and reviewed per week (adjusted[28])



This quarter we received seven self-reporting notices from participants regarding errors in their rebids. We decided not to take action on these errors. As such, no warnings were issued and no participants had their warning count reset to zero during the quarter.

2.8 Jurisdictional Derogations

Chapter 9 derogations exempt New South Wales power traders and Queensland nominated generators (for the purposes of exempted generator agreements) from complying with the Electricity Rules to the extent there exists:

- Any inconsistency between the Rules and a contractual requirement under the relevant agreement between the government and other entities
- Any other specified exemption in the jurisdictional derogations.

Relevant participants must notify the AER at AERinquiry@aer.gov.au of any act or omission which partly or wholly constitutes non-compliance with the Electricity Rules. No non-compliances were reported this quarter.

28 There was a significant increase in automatically triggered rebids from August to November 2014 when one participant's automated bidding system submitted rebids without including a time adduced which was subsequently corrected. This has been detailed in a previous QCR. **Figure 6** has been adjusted by removing the erroneous rebids.