Quarterly Compliance Report:

National Electricity and Gas Laws

1 October – 31 December 2016

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERinquiry@aer.gov.au
AER Reference: 61487-D17/20120

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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 October 2016 to 31 December 2016 (the December 2016 quarter) for gas and electricity markets.

Gas

This QCR highlights the recurrence and impacts of demand over forecasting trends in the Sydney Short Term Trading Market (STTM). It outlines the continuation of the trend across 2016 and the AER's commitment to understanding and addressing pronounced incidences of over forecast demand. It also identifies some recent demand forecasting errors within Victoria's Declared Wholesale Gas Market (DWGM).

In its September 2016 QCR, the AER flagged that it had commenced an investigation of the events surrounding the Longford Gas Plant outage on 1 October 2016[1]. Recognising the importance of Longford gas supplies to Australia's east coast gas markets, the AER has initiated a targeted compliance review of participant offers at the Longford injection point. We have flagged the targeted compliance review in this report.

This report also includes information on the Natural Gas Services Bulletin Board (the Bulletin Board). The Bulletin Board was an important part of the AER's compliance monitoring in 2016, noting that gas market participants were subject to new reporting requirements from 6 October 2016. During the December 2016 quarter, the AER monitored Bulletin Board registered facilities for compliance with the new requirements and outlines its findings here.

Electricity

This report includes an update on the AER's ongoing compliance investigations into system events in the National Electricity Market (NEM). Specifically, the reviews address the Black System event in South Australia on 28 September 2016 and the separation of the South Australian market from the NEM on 1 December 2016. The reviews are examining participant compliance and system operation both during and in the lead-up to these events.

[1] The significant price variation report – 1 October 2016 (Victorian gas market) was published on 21 December 2016: http://www.aer.gov.au/wholesale-markets/market-performance/significant-price-variation-report-1-october-2016-victorian-gas-market

Further to our compliance reviews the AER is investigating high price events during the 2016/17 summer. This includes analysis of the causes of high prices in Queensland during February 2017. Wholesale market prices in several NEM jurisdictions breached the AER's reporting thresholds and we will be publishing the results of our investigations into the events in accordance with our obligations under the Electricity Rules. Concerning the high price events in South Australia on 8 February 2017, the AER will be undertaking a compliance assessment of the load-shedding that occurred in the State on that day.

The high price reports published by the AER during the December 2016 quarter have been tabled in this report. This report also tables the high price reports that are currently pending.

During the December 2016 quarter the AER finalised four reviews into potential non-compliance with generation dispatch instructions. Three of these investigations led to the AER issuing infringement penalties. The other investigation led to an agreement, with the market participant, to an administrative undertaking to conduct ongoing performance reporting in 2017. The details of these compliance reviews are provided here.

In April 2016, the electricity transmission business, Transgrid, sought advice from the AER as to whether the regulatory investment test (RIT-T) should be applied to the proposal to build a second transmission supply to the Australian Capital Territory (ACT). The AER has considered Transgrid's proposal and presents its findings in this report.

This QCR also outlines our approach to participant readiness for the introduction, from 1 December 2017, of competition in metering and related services ('Power of Choice'). We highlight the opportunity for participant involvement in AEMO's Power of Choice Implementation Program and emphasise that, in 2017, participant readiness for metering contestability will be a compliance priority of the AER.

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[2] and other persons; and
- investigating breaches, or possible breaches, of provisions of the legislative instruments under our jurisdiction.

Consistent with our statement of approach,[3] 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).

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

3 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.

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

While most obligations under the Electricity and Gas Rules do not require registered participants to establish specific compliance programs, 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 Hub (GSH).

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

1.1 Short Term Trading Market

1.1.1 Significant Price Variations

We are required to identify and report on any Significant Price Variations (SPVs) in the STTM. Our "SPV triggers for the STTM" set out what constitutes a SPV[4]. When our thresholds are breached, we investigate and report in accordance with our obligations under the Gas Rules.

Reporting on SPVs is part of the process of identifying systematic behavioural concerns in the STTM and analysing market performance. The SPV reports identify the reasons for price variations, which may result from material changes in market conditions, behavioural issues or other reasons. The reports are published on the AER's website[5] and are useful reference documents for stakeholders.

The AER identified two SPVs across the STTM's three hubs (Adelaide, Sydney and Brisbane) during the December 2016 quarter. In both cases, high Market Operator Service (MOS) payments breached the AER's reporting thresholds[6]. The SPVs occurred at the Sydney and Adelaide hubs on 7 November and 21 November, respectively.

The SPV event at the Sydney hub generated high MOS service payments ($329 793) and may be associated with trends in demand forecasting errors at the hub (refer to section 1.1.4 below). The AER has been examining the link between high MOS and over forecast demand at the Sydney hub in recent years and will be separately conducting more detailed analysis in early 2017.

The SPV event at the Adelaide hub is associated with counteracting MOS[7] and featured a record payment for the hub ($367 334). We published a SPV report on counteracting MOS in

4 SPVs in the STTM Guideline: http://www.aer.gov.au/system/files/Significant%20Price%20Variations%20in%20the%20STTM%20-%20Guideline%20-%2021%20December%202012.pdf

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

6 MOS gas is provided by a STTM pipeline operator in balancing positive or negative pipeline deviations at a trading hub at the end of the gas day. Participants who own this gas are compensated for this service. MOS payments in excess of $250 000 trigger an AER investigation and report.

7 Counteracting MOS occurs when MOS services are provided by pipelines supplying the same hub. In this case, increased MOS gas is required on one pipeline and decreased MOS gas is required on another pipeline. This means that the supply volumes on each pipeline are not allocated according to the market schedule, with one pipeline compensating for the supply shortfall of the other.

Adelaide in 2013 and will be analysing the most recent event to understand its causes. We will publish separate reports on the Adelaide and Sydney SPVs in March 2017.

We endeavour to publish our SPV reports for gas and $5000 per megawatt hour reports for electricity in a timely manner and in accordance with timeframes required by the Gas Rules and 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[8].

1.1.2 Moomba Adelaide Pipeline

During the September 2016 quarter, we approached Epic Energy as part of our analysis of high winter gas prices and a constraint on the Moomba Adelaide Pipeline System (MAPS). Our discussions with the business revealed that, on 5 July 2016, Epic had introduced a new calculation methodology for gas deliveries to the Adelaide STTM. During the December quarter we again approached Epic to get a clear understanding of its new calculation methodology and whether this enabled Epic to meet the accurate daily reporting requirements in the Gas Rules.

Prior to 5 July 2016, the capacity available to shippers into Adelaide was calculated based on the removal of upstream nominations (noting that demand centres like Whyalla draw southbound gas from the MAPS upstream of Adelaide). The capacity into Adelaide on the MAPS was, in effect, a residual capacity.

From 5 July, the capacity available to shippers into Adelaide has been calculated based on what could be re-nominated from upstream delivery points. As a consequence, Epic has been able to submit higher capacities for flows to the Adelaide hub. This calculation methodology, according to Epic, has provided more flexibility to shippers.

Epic conferred with the market operator throughout the proposal and implementation stages and AEMO has not raised any concerns. Neither have market participants that we subsequently contacted. We consider that the new arrangement by Epic meets its obligations under Gas Rule 414(1) regarding the accurate daily reporting of the capacity available for delivery to the Adelaide hub.

We anticipate that shippers on the MAPS will continue to meet their obligations under the good faith provisions in the Gas Rules. Epic's new calculation methodology may increase the potential for trade-offs between gas scheduled into Adelaide and nominations at upstream delivery points on the MAPS. We will be monitoring pipeline activity to see if shippers continue to honour downstream schedules into Adelaide, including by renominating if necessary.

In light of the change to the calculation methodology for the MAPS, we have begun to review the methodologies used to calculate available capacities on other transmission pipelines

8 The Gas Rules for the STTM require the AER to publish its SPV report within 60 business days following the final statement for that gas day. The Victorian arrangements in the Gas Rules require the AER to publish its SPV report within 20 business days following the final statement for that gas day.

supplying STTM hubs, which we first audited at market-start[9]. We will engage with pipeline operators, in early 2017, to better understand their calculation methodologies and to consider any implications in terms of participant compliance with the Gas Rules.

1.1.3 Origin Energy Scheduling Error (23 September)

In October 2016, we investigated a scheduling error on the Eastern Gas Pipeline (EGP). The error contributed to a high MOS payment in the Sydney STTM of $204,000 on 23 September 2016.

The error was a 10TJ variation between Origin Energy's scheduled deliveries to the Sydney STTM (on the EGP) and Origin's corresponding scheduled EGP injections in Victoria. The variation produced a supply/demand imbalance in Sydney and the requirement for MOS balancing gas.

Origin reported that a manual data entry error was made on 23 September that was not identified until the following day. Origin subsequently reviewed its processes and introduced an automated facility to identify such errors when they occur. We took no further action and here remind gas market participants of the importance of reviewing their scheduling systems on a regular basis.

1.1.4 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 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 MOS payments in the STTM, whereby large amounts of gas are required to address the imbalance.

The Gas Rules[10] require 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.

In 2012, we undertook a project in response to ongoing occurrences of inaccurate demand forecasts from some Sydney STTM participants. We had concerns regarding biases toward under and over forecasting of demand, as well as concerns regarding large avoidable demand forecast errors; for example, those caused by system errors.

Throughout 2013, we developed metrics to identify trends in demand forecasting errors. Participants were contacted regarding their performance and asked to review their systems and consider changes to minimise errors. We subsequently identified a trend to reduced forecasting errors and lower MOS balancing gas requirements during 2013 and 2014.

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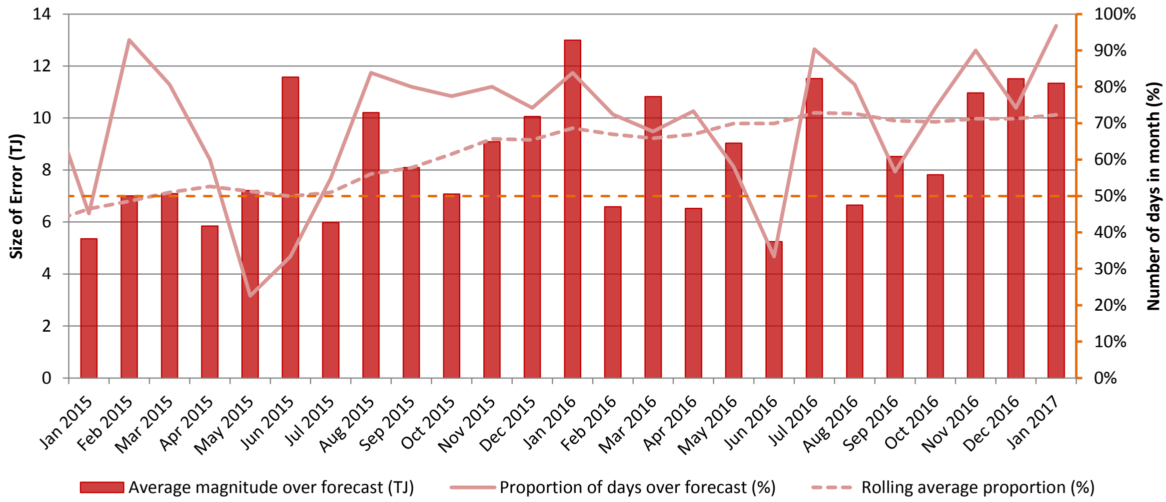
9 The Adelaide STTM commenced in September 2010. The Sydney and Brisbane STTMs commenced in December 2011 Brisbane.

10 Rule 410(1).

In our last QCR, we identified a recurrence of the over forecasting trend in the Sydney STTM from mid-2015. After declining through 2014, there was a return to high over forecasting in late 2014 and early 2015 before declining toward the middle of 2015. As shown in Figure 1, the incidence of over forecasting then increased from mid-2015 to become a long term trend.

Figure 1: Sydney Hub forecasting performance metric (since January 2015)



On average, demand was over forecast 71 per cent of the time across the 2016 calendar year[11]. This figure was higher during the December 2016 quarter, with over forecasting occurring 79 per cent of the time. As indicated in Figure 1, the proportion of over forecast days reached 90 per cent for the month of November, with the level of over forecast demand averaging 11TJ per day. More recent data, indicating that 97 per cent of the days across January 2017 were over forecasted (hub aggregate), has further raised our concern that this is a persisting trend.

Large demand forecasting inaccuracies lead to large balancing gas volumes with higher resultant MOS gas payments, which we report on in our Gas Weekly. This adds to participants' costs of doing business in the Sydney STTM. Compared to the corresponding period in 2015, Sydney MOS payments for July to December 2016 were up 145 per cent, influenced by a higher number of days of over forecasting and higher average errors for those days (as shown in figure 1).

Participants have argued that revised settlement runs (including revisions out to 9 months) may heavily influence the proportional split of gas allocations among hub participants and whether days were under or over forecast. We are considering these claims but are not convinced that the preliminary nature of the data completely accounts for the observed trend. We will, however, continue to examine the demand forecasting performance of participants over the longer term[12]. We will also monitor how participants calibrate their models over time, such as where they have indicated to us that customers are responding differently to temperature changes than they did in the past.

11 The rolling average proportion for the Sydney hub over the previous 12 months.

12 Figure 1 includes revised settlement data up to March 2016.

We have recently commenced a round of meetings with the Sydney hub's larger participants to discuss trends in demand forecasting errors. The meetings have included discussions with AGL, who over forecast on 94 per cent of days during the 2016 December quarter (based on preliminary allocation data).

Also in 2016, we investigated breaches of our reporting threshold for MOS gas payments in Sydney and found that over forecast demand significantly contributed to high winter balancing gas payments[13]. We are currently investigating a high MOS payment in the Sydney STTM on 7 November and will publish a SPV report on that event[14]. Preliminary analysis indicated simultaneous over forecasts by the major participants.

In 2017, we have committed to better understanding demand forecasting trends at the Sydney hub and will work with market participants to fully understand the causes of demand over forecasting, including identifying any incentives that lead to demand over forecasting. We will also work to identify possible solutions.

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13 Reported in the AER's July and August 2016 SPV Report, http://www.aer.gov.au/wholesale-markets/compliance-reporting/significant-price-variation-report-july-august-2016

14 The MOS payment exceeded $250,000, breaching the AER's SPV reporting threshold and triggering an investigation. The AER will publish its report in March 2017.

1.2 Victorian Gas Market

1.2.1 Demand Forecasting in Victoria

The Gas Rules[15] require each Victorian Declared Wholesale Gas Market (DWGM) trading participant, who expects to withdraw quantities of natural gas from the DWGM on a gas day, to submit, in good faith, demand quantities which represent the participant's best estimate of the quantity it expects to withdraw in each hour of the relevant scheduling horizon.

In 2016, we identified two DWGM participants (retailers) with a significant history of error in their demand forecasting. One participant displayed a consistent over forecasting bias which may not meet the required standard under part 19 of the Gas Rules[16]. The other participant displayed swings between over forecast demand and under forecast demand across 2015/16.

The first participant's demand forecast consistently exceeded its actual demand by more than 20 per cent. While the level of demand for the participant was relatively low, it had potential to impact prices during high demand, including the winter period (when there can be inelasticity of supply offers during high demand).

The first participant was contacted and committed to revising its demand forecasting systems to better detect forecasting errors. The participant also agreed to submit daily demand data to the AER. It did so during the October 2016 quarter and will continue to do so during the March 2017 quarter. This will enable us to monitor the participant's compliance with Part 19 of the Gas Rules. We will be looking for improved demand forecasting accuracy.

The second participant displayed periods of bias toward either under forecast or over forecast demand. We met with the participant during January 2017 and discussed these trends. The participant indicated that it had recently amended its forecasting model. It agreed to provide us with further data, in early 2017, to assist with the on-going assessment of its forecasting performance.

1.2.2 Longford Gas Plant Outage

On 1 October 2016, a SPV occurred in Victoria's DWGM. The SPV followed an unscheduled outage at the Longford gas plant at 4:26 am. Total production ceased at Longford, requiring AEMO to issue a "declaration of threat to system security" in Victoria. Longford returned to service during the morning and ramped-up production throughout the day. Scheduled prices ranged between $9.99/GJ and $33.75/GJ and approximately $3.1 million in ancillary payments were generated across the market.

In association with the Longford outage, a contingency gas event was declared for the Sydney STTM (the Longford Gas Plant is a major supply source for Sydney). However, contingency gas was not ultimately required.

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15 Rule 213(2)(a)

16 Under Clause 213(2)(a) of Part 19 of the Gas Rules the Market Participant must ensure that 'each demand forecast submitted by that Market Participant is made in good faith and represents that Market Participant's best estimate of the quantities of gas it expects to withdraw from the Declared Transmission system…'.

The AER published a [Significant Price Variation (SPV)] report on the Longford outage on 21 December 2016. While we found no instances of non-compliance by participants, we did identify some potential follow up actions in respect of the publication of information for participants on the day. This included AEMO's access to information from participants, to help it manage the event, and the methodology of allocating uplift payments.

In February 2017, we raised these matters at the Gas Wholesale Consultative Forum (GWCF). AEMO provided an overview of how it publishes updates during a gas day to help ensure participants have access to new information as soon as possible. The forum discussed the extent to which the issues faced on 1 October could be incorporated into a training exercise later this year. AEMO also noted that it intends bringing a paper to a future GWCF on potential improvements to the methodology of allocating uplift payments.

AEMO published a compliance report on the Longford event on 4 January 2017 and self-identified two breaches of the Gas Rules. The breaches pertain to AEMO's failure to declare that it considered the threat to system security to be at an end (Rule 341(5)) and to AEMO's role in an unintended scheduling result for Victoria's 10pm schedule (Rule 217(4)).

We accept that the first breach produced no material outcomes. We also acknowledge that AEMO has recognised that a formal declaration of an end to the threat to system security should be part of the process applied to future system security events. AEMO considered this second breach to be material (exceeding the financial impact thresholds set out in the Rules) and is notifying participants that may have been negatively impacted. In such circumstances, the Rules provide a mechanism where participants can seek compensation in accordance with the dispute resolution processes. The AER has no formal role in the dispute resolution process unless a party to a dispute requests it. We propose taking no further action and will monitor outcomes in this area.

1.2.3 Targeted Compliance Review – Longford Injections

We have initiated a targeted compliance review concerning gas market scheduling at the Longford injection point. Longford injections can impact significantly on East Coast Gas Markets, noting that the Longford Gas Plant is the majority supplier of gas to Victoria's DWGM and an important supply source for Sydney's STTM.

During 2016, we were informed of approximately 50 occasions where there was a significant mismatch between the market schedule for injections into the DWGM at Longford and the amount confirmed to AEMO by Esso as the operator of the facility. There were several more occurrences of discrepancies during January/February 2017, with the mismatch between the market schedule and confirmed volumes ranging between approximately 10TJ (low) and 60TJ (high). In most cases the mismatch was high (meaning the injected volumes at Longford exceeded the market schedule).

We are examining participant offers around the Longford injection point. Preliminary work has revealed instances where participants nominated an incorrect amount through a portal that Esso operates. We will examine these instances further and will also examine the larger portion of mismatched scheduling that is unexplained by information received to date from market participants, including in consultation with AEMO and Esso. In cases where mismatches are attributed to manual errors within the participant's business, we would welcome any remedial actions by the participant, including improvements to its systems and staff training.

A separate issue that has emerged, as part of our analysis of Longford injections, is the lack of a common practice between market participants concerning participant rebids in response to supply interruptions/changes[17]. It appears likely that there have been instances where participants have rebid reduced quantities in relation to a supply constraint (recognising lower volumes contractually available to inject) and been financially penalised compared to participants that do not submit rebids[18]. We acknowledge that rule 211(4) of the Gas Rules (applying to on-the-day rebidding) does not mandate that bids must be changed if the volumes available change. However, we will explore the market-wide impact of such inconsistent practices.

A progress report on both these issues will be included in our next QCR.

1.2.4 Significant Price Variation

Further to our performance monitoring obligations for the STTM, we are required to identify and report on any SPVs in Victoria's DWGM. We have established price thresholds that trigger these SPV reports[19].

One SPV was identified in Victoria's DWGM during the December quarter. The SPV occurred on 14 October in the form of a large negative ancillary service payment of $365,612. We will publish a separate report on this event in March 2017.

We endeavour to publish our SPV reports for gas and $5000 per megawatt hour reports for electricity in a timely manner and in accordance with timeframes required by the Gas Rules and 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[20].

1.3 Gas Supply Hub

1.3.1 Wallumbilla Single Market Product (optional hub services)

The Wallumbilla Compression Product for the Wallumbilla Gas Supply Hub Exchange (Wallumbilla Exchange) commenced on 26 October 2016. The compression product was introduced as part of the Hub's transition away from having three different trading locations. Currently, liquidity at the Wallumbilla Exchange is spread across three points at the Queensland Gas Pipeline (QGP), South West Queensland Pipeline (SWQP) and the Roma

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17 Participants can rebid their volumes for Victoria's intra-day schedules (10am, 2pm,6pm and 10pm).

18 The AER recognises that the rule requirement for intra-day bids as opposed to before the day bids does not mandate rebidding.

19 Victoria's DWGM SPV Guideline: http://www.aer.gov.au/system/files/Guideline%20-%20Significant%20price%20variation%20for%20Victorian%20declared%20wholesale%20market.pdf

20 The Victorian arrangements in the Gas Rules require the AER to publish its SPV report within 20 business days following the final statement for that gas day. The Gas Rules for the STTM require the AER to publish its SPV report within 60 business days following the final statement for that gas day.

Brisbane Pipeline (RBP)[21]. From March 2017, the supply hub will transition to a single trading location.

Since 26 October, the compression product has been tradeable on the Wallumbilla Exchange, where market participants can access compression and redirection services (and, in the case of compression, where the hub owner or existing contracted shippers may have spare compression for sale). No trades were recorded during the compression product's first three months of availability. In accordance with our requirements under the Gas Rules, we will monitor for any trading on the exchange with a view to ensuring that members are compliant with their market conduct obligations.

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. While there has been a number of offers and some bidding for gas at the Moomba hub, there have been no participant transactions facilitating trading of a spread product or gas at Moomba.

1.4 Natural Gas Services Bulletin Board

In December 2015, the Australian Energy Market Commission (AEMC) released its final rule determination to improve information provided to the east coast gas market via the Natural Gas Services Bulletin Board. The *National Gas Amendment (Enhanced Information for Gas Transmission Pipeline Capacity Trading) Rule 2015* required registered Gas Bulletin Board Facilities to commence providing additional information, for publication on the Bulletin Board, from 6 October 2016. The Bulletin Board requirements are set out in Chapter 7 of the Gas Law and Part 18 of the Gas Rules.

New information required from pipeline operators, storage facilities and production facilities includes:

- detailed facility information; and
- medium-term capacity outlooks.

New information required from pipeline operators includes:

- information on Bulletin Board shippers that have contracted capacity;
- secondary trade data[22];
- 12 month outlooks on uncontracted primary pipeline capacity;
- actual receipts and deliveries of gas from the pipeline to each demand and/or production zone; and
- actual daily receipts and deliveries of gas for each receipt or delivery point.

21 Refer to Figure 2 below.
22 Pipeline operators to provide secondary capacity trading information from their trading platforms.

New information required from storage providers includes:

- 12 month outlooks of uncontracted storage capacity;
- the actual daily quantity of natural gas held in storage; and
- nominated and forecast storage injections and withdrawals (daily and during the day if information changes).

1.4.1 Bulletin Board Monitoring

In 2016, we made compliance with Bulletin Board reporting obligations a priority for the year. We monitored gas market participant preparations in advance of the 6 October commencement of the Gas Rules amendments, as well as participant compliance with the new reporting requirements from that date. The monitoring extended to newly-captured facilities across the east coast gas markets, including transmission pipelines, storage facilities and production facilities associated with Queensland's LNG export industry. From 6 October, the operators of these facilities were required to report their activity to the Bulletin Board.

1.4.2 Reporting Exemptions

A market participant may seek an exemption from its obligation to report to the Bulletin Board, according to exemption criteria outlined in the Gas Rules. AEMO is responsible for granting exemptions and has outlined its exemption application process in the *Natural Gas Bulletin Board Procedures*.

The AER does not have a formal role in the exemption application process unless a participant contests an AEMO decision and seeks to progress matters under the dispute resolution processes outlined in the Gas Rules. Participants sometimes approach the AER to confirm that we do not have concerns that their exemption could fail to comply with the Gas Rules.

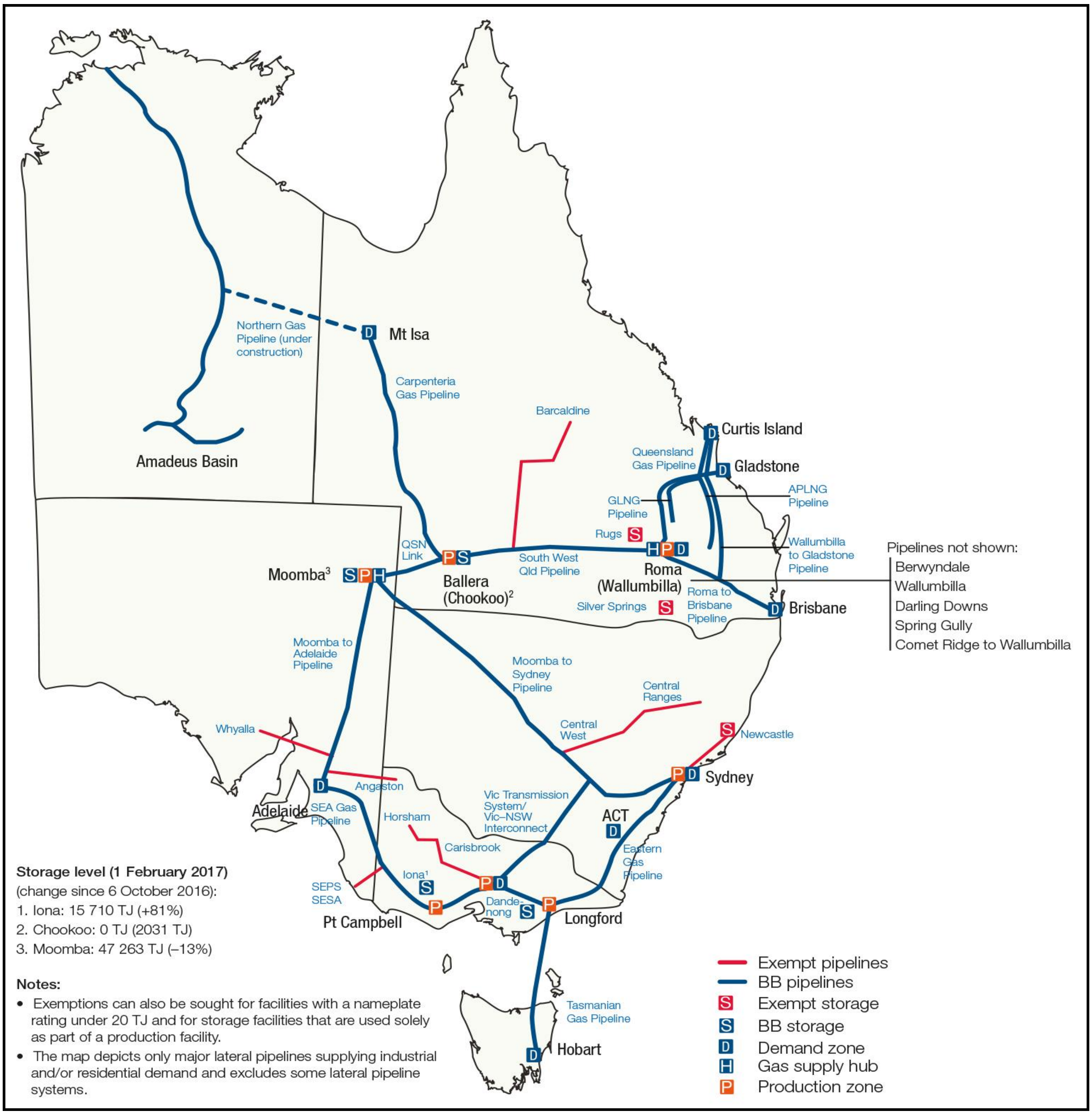
Reporting exemptions currently apply to a number of transmission pipelines, storage facilities and production facilities. This is principally the result of the zonal model used for Bulletin Board reporting, which is based on gas flows between production and demand zones. Under this model, exemptions 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.

Figure 2 depicts the east coast gas grid and the zonal model used for Bulletin Board reporting. Key facilities that are currently exempt from reporting are identified. Both exempted and captured storage facilities are shown. Captured storage facilities are now required to report their storage levels daily[23]. Figure 2 shows the reported storage levels on

[23] This information is used in the AER's weekly gas reports: http://www.aer.gov.au/wholesale-markets/market-performance

1 February 2017, including changes to those levels since reporting commenced on 6 October 2016[24].

Figure 2: Natural Gas Services Bulletin Board (1 February 2017)



1.4.3 Compliance with New Reporting Requirements

Some market participants sought and received specific exemptions from the new reporting requirements. This has included agreements to report under interim arrangements or alternative calculation methodologies. Alongside the formal exemptions that apply under the Bulletin Board's zonal model, these specific exemptions contribute to inconsistencies across the reporting landscape. Whilst the objective of the new reporting requirements is to improve

24 On 22 February 2017, AEMO issued a market notice informing participants that it had deregistered Ballera Gas Plant and Chookoo Storage Ballera from the Gas Bulletin Board, effective 8 February 2017. The operator of these facilities has informed AEMO that they have ceased operation.

the transparency of east coast wholesale gas markets, the new requirements do not enable the capture of all Bulletin Board registered facilities under consistent arrangements.

In our September 2016 Quarterly Compliance Report we identified three participants that would continue to report using manual systems and one participant that would report under alternative arrangements. This included Australia Pacific Liquefied Natural Gas (APLNG), which has since automated its systems and has complied with its reporting obligations since October 6. It also included a manual data transfer arrangement between AEMO and APA's Dandenong LNG. No non-compliance issues have been identified in relation to the Dandenong LNG arrangement[25].

Lochard Energy

Lochard Energy operates the Iona Underground Gas Storage facility at Port Campbell in Victoria. The Iona facility is part of the Port Campbell production zone and is directly connected to Bulletin Board pipelines. From 6 October 2016, storage facilities were required to report each day on their aggregated injections and withdrawals for that gas day; 7 day forecasts of their injections and withdrawals; and timely updates on changes to this information (Rule 169C).

Lochard was not fully compliant with the new reporting requirements from 6 October 2016. We determined not to take action and negotiated an interim arrangement, aimed at Lochard's partial compliance with Rule 169C, whilst it transitioned from manual to automated reporting. This meant that, from 6 October, Lochard was not providing timely updates on all gas days outside of business hours. Lochard instead provided late data for the Iona storage facility including the provision of weekend data on Mondays.

In February 2017, Lochard reported to us that it had introduced an automated Bulletin Board reporting system. This, according to Lochard, means that, from January 2017, reporting for the Iona facility is fully compliant with Rule 169C. We will be examining the 2017 data that Lochard has submitted to AEMO to verify this claim.

Santos GLNG

Santos GLNG produces gas within the Roma production zone and operates the Comet Ridge to Wallumbilla Pipeline (CRWP) and the GLNG Gas Transmission Pipeline (GTP). The CRWP and GTP are both Bulletin Board pipelines and connect to create a major transmission flow-path through the Roma production zone. From Roma, the CRWP runs south to the Wallumbilla gas supply hub and the GTP runs north to Santos GLNG's export facilities at Curtis Island. This represents a transmission flow-path between three Bulletin Board zones.

The new obligations require reporting of receipt and delivery point data for the Roma production zone. However, the metering of this data is problematic due to Roma's complicated network of lateral pipelines. The network integrates the CRWP and GTP with Santos GLNG's production and storage facilities within the Roma zone. Its complex

25 Participants do not require automated reporting systems to be compliant. However, a transition toward more detailed reporting can be expected to make compliance more onerous if participants continue to report using manual systems.

configuration makes it difficult to report receipt and delivery point data for the CRWP and GTP such that gas flows, between the respective zones, are accurately measured.

Given the network of lateral pipelines associated with the Roma production zone, Santos GLNG proposed an alternative reporting arrangement. This includes data reporting not required by the Gas Rules. The intention of this approach is to enable AEMO to build a mass balance of gas flows to and from the Roma production zone, subsequently delivering the desired transparency to the Bulletin Board.

Following detailed discussions with GLNG, both AEMO and the AER accepted this arrangement, with the understanding that it is does not strictly comply with the Gas Rules. We will continue to monitor the arrangement and will confer with AEMO to verify the accuracy of GLNG's data over time. The data submitted during the December 2016 quarter has satisfied AEMO that GLNG's reporting methodology provides an accurate measure of flows to and from Roma. We will continue to monitor GLNG's reporting for data accuracy.

1.4.4 Observations and Future Reporting

Participants' ability to comply with the new Bulletin Board reporting obligations during the first three months of operation has been promising. Data submission errors, including late submissions, have occurred but the impacts have been minimal and AEMO has been able to identify and rectify errors quickly with the cooperation of market participants.

We anticipate that Bulletin Board reporting will become more accurate as participants continue to bed-down their new systems. In addition to our ongoing compliance monitoring, we will consider improvements to how Bulletin Board reporting arrangements are communicated to the market, noting that certain participants may not have been aware of the specific exemptions granted to other participants until the November publication of the AER's last QCR.

The new reporting arrangements have made a more comprehensive and consistent body of information available to the market (with the exception associated with the partial capture of Santos GLNG). However, information gaps continue to exist due to formal exemptions under AEMO's zonal model. These exemptions would be removed under the proposed stage 2 reforms from the AEMC's 2016 gas market review report[26]. Facilities that are currently exempt, including lateral pipelines and certain storage facilities (as shown in Figure 1), will be captured. Under the proposed timeline, participants receiving formal or specific reporting exemptions may need to transition from their current arrangement in 2018[27].

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26 Stage 2 Final Report, East Coast Wholesale Gas Market and Pipeline Frameworks Review.

27 The AER will continue to monitor the effectiveness of Bulletin Board reporting, with a view to providing feedback to ongoing reforms. In its September 2016 QCR, the AER highlighted the capability for pipelines to be advertised as storage facilities (for example the Tasmanian Gas Pipeline). In such cases, the pipeline's uncontracted storage capacity need not be reported, thus obscuring the reliability of its uncontracted transportation capacity data. The AER will report this potential outcome in its feedback to on-going Bulletin Board reform process.

1.5 Retail Market Procedures

Under the Gas Law, AEMO has the ability to make Retail Market Procedures regulating a retail gas market.[28] There are four sets of Retail Market Procedures covering Queensland, Victoria, New South Wales and the ACT and South Australia respectively. The procedures impose a number of obligations on participants including in relation to the provision of metering data, the Gas Interface Protocol, customer transfer processes and settlements. Section 91MB of the Gas Law requires compliance with the Retail Market 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 the 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. The obligation to comply with AEMO's direction is a civil penalty provision.

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

- AEMO's failure to provide acknowledgement within 4.5 hours for medium priority transactions on three occasions during September and October 2016. These delays were caused by misconfiguration in the Trading Networks clustering settings at the Full Retail Contestability (FRC) Hub after an internal disaster recovery test, and connection pool settings in AEMO's Gas Retail Market Business System (GRMBS), respectively. AEMO has revised its protocols for health checks after internal disaster recovery tests and revised the relevant setting in the GRMBS.

- AEMO's delay, on three occasions during September 2016, in providing the STTM Network Allocation Data (NAD) file for the NSW and ACT Gas Retail Market. These delays occurred due to:

    - an increase in processing time for the daily calculations;

    - processing of the Interval Meter Reading Data file was incorrectly identified as not being completed successfully. The commencement of daily calculations was subsequently delayed; and

    - a delay in running the database application process which caused insufficient memory on the database server for GRMBS applications to run.

AEMO has implemented new monitoring processes and made a number of changes to the database to streamline processing of daily calculations.

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

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 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.[29]

According to the 'three stage process' introduced in late 2010 and updated in 2012,[30] 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.

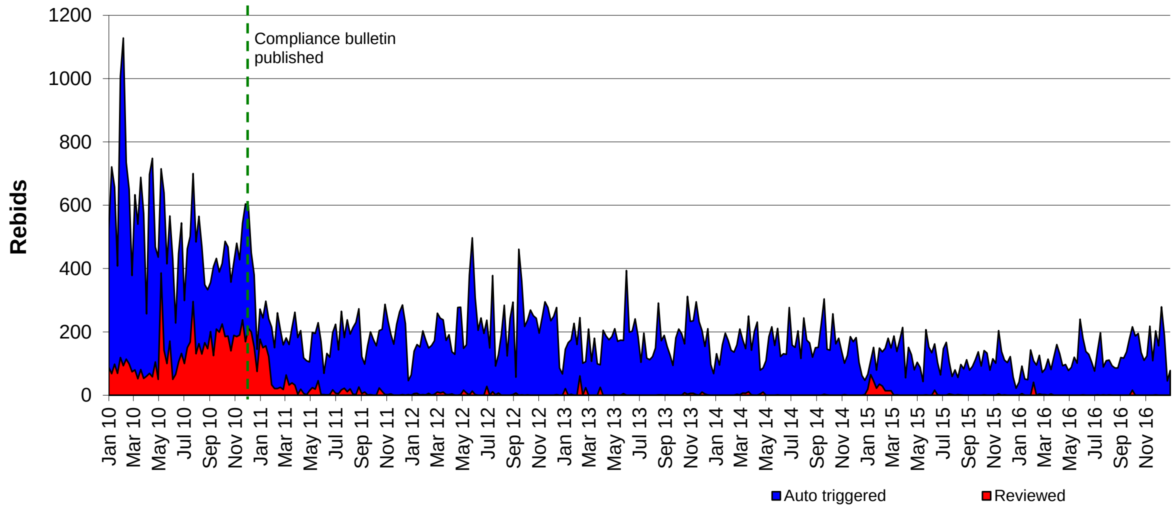
Frequent submission of offers, bids and rebids which do not meet the relevant requirements of the Electricity Rules can seriously and adversely impact the NEM. In particular, the quality of information available to relevant participants and other persons is reduced, which in turn reduces market efficiency.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

As shown below in Figure 3, the number of rebids automatically triggered as requiring initial examination (indicated by the blue area) has fallen markedly since 2011.

29 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'.

30 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 3: Rebids auto-triggered and reviewed per week (adjusted[31])



This quarter we received 12 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.

2.2 Rebidding and Technical Parameters Guideline

The Bidding in Good Faith (also known as False or Misleading) and Generator Ramp Rate rule changes came into effect on 1 July 2016. In response to these rule changes we are required to make consequential amendments to our Rebidding and Technical Parameters Guideline.

In late September 2016 we published a draft consultation Guideline and in December 2016 we published a draft Guideline. After considering stakeholder input we published our final Rebidding and Technical Parameters Guideline in late February 2017.

2.3 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[32]. These reports are available on our website[33].

During the December quarter, we reported on the following extreme price events, including three events dating from the September 2016 quarter.

31 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 1 has been adjusted by removing the erroneous rebids.

32 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.

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

	Event Date	High Price Period	Region	Market	Highest Price
1	13/7/2016	6:30	SA	Energy	7068.49
2	14/7/2016	18:30	SA	Energy	6917.55
3	11/8/2016	18 trading intervals (11am–19:30pm)[34]	SA	FCAS	11469
4	1/9/2016	20 trading intervals (7:30am–17:00pm)[35]	SA	FCAS	9999.69
5	16/9/2016	12 trading intervals (8am–15:30pm)[36]	SA	FCAS	11250
6	18/11/2016	15:30	NSW	Energy	11700.63

On 2 February 2017, the AER also released the following reports on the extreme price events of 1 December 2016 (refer to item 2.4 below).

	Event Date	High Price Period	Region	Market	Highest Price
1	1/12/2016	2:00, 3:00, 3:30	SA	Energy	13766.58
2	1/12/2016	10:30	SA	Energy	9175.47

Currently, we are preparing reports relating to high priced events on the following days. The reports will be published in accordance with timing requirements set out in the rules.

	Event Date	High Price Period	Region	Market	Highest Price
1	18/10/2016	7:00- 8:30, 19:00 - 23:00	SA	FCAS	13083.33
2	9/11/2016	04:30 - 18:30	SA	FCAS	7333.94
3	25/11/2016	04:30 - 11:30	SA	FCAS	11014.17
4	13/01/2017	17:00	QLD	Energy	13882.77
5	14/01/2017	16:30-17:30, 19:00	QLD	Energy	12641.69
6	23/01/2017	5:30 - 6:00	SA	FCAS	9333.333
7	2/02/2017	17:00 - 17:30	QLD	Energy	13399.95
8	6/02/2017	16:30 - 17:00	NSW/QLD	Energy	11692.09

34 11:00, 11:30, 12:00, 12:30, 13:00, 13:30, 14:00, 14:30, 15:00, 15:30, 16:00, 16:30, 17:00, 17:30, 18:00, 18:30, 19:00, 19:30.

35 7:30, 8:00, 8:30, 9:00, 9:30, 10:00, 10:30, 11:00, 11:30, 12:00, 12:30, 13:00, 13:30, 14:00, 14:30, 15:00, 15:30, 16:00, 16:30, 17:00.

36 8:00, 8:30, 9:00, 11:30, 12:00, 12:30, 13:00, 13:30, 14:00, 14:30, 15:00, 15:30.

	Event Date	High Price Period	Region	Market	Highest Price
9	8/02/2017	17:30 - 18:30	SA	Energy	11141.35
10	9/02/2017	17:00	NSW	Energy	7822.25
11	9/02/2017	17:00, 17:30, 18:30	SA	Energy	9509.52
12	10/02/2017	17:00	QLD	Energy	12221.4
13	10/02/2017	17:00 - 18:00	NSW	Energy	14000
14	11/02/2017	16:30- 17:30	QLD	Energy	8568.9
15	12/02/2017	17:30	QLD	Energy	9004.95

In addition to examining the causes of high prices on 8 February and 10 February 2016, we will review the circumstances that led to load-shedding in South Australia (8 February) and industrial curtailment in New South Wales (10 February).

We endeavour to publish our $5000 per megawatt hour reports for electricity (and our SPV reports for gas) in a timely manner and in accordance with timeframes required by the Electricity Rules and Gas Rules. We sometimes make full use of these timeframes to ensure that these reports are accurate, comprehensive and reflective of consultations with market participants.

2.4 Ongoing Compliance Review Updates – South Australian Black System Event and 1 December 2016 Separation Event

During the last quarter, there were two major events in the market:

- At 12:16 am on 28 September 2016, South Australia experienced a state-wide blackout. The blackout was triggered by a severe weather event damaging transmission and distribution electricity assets. The consequential reduction in output from some wind farms and loss of the Heywood interconnector resulted in all remaining customer load and electricity generation in South Australia tripping off. Supplies to most customers were restored within 24-48 hours, with AEMO declaring the black system event concluded at 18:25 on 29 September. Following the events, AEMO suspended the SA market and invoked pricing and dispatch schedules. The South Australian market remained suspended under direction by the South Australian jurisdiction until 11 October.

- In the early hours of Thursday 1 December, the South Australian region separated from the rest of the NEM. At the time, a planned outage of one of the Heywood to Mortlake 500kV lines by AusNet Services was underway. At around 12.16 am, a fault near the Heywood substation tripped the remaining lines, tripping the Heywood interconnector. The Portland smelter was also disconnected. As SA was importing energy at the time, the under-frequency load shedding scheme operated and disconnected approximately

220 MW of load in South Australia. Power was restored to affected SA customers at 1:45 am and SA re-joined the NEM at 4:41 am. The Portland smelter had power restored at around 3:30 am.

As set out in our Compliance and Enforcement Statement of Approach (April 2014), the AER prioritises investigating compliance during significant market events. We are investigating all aspects of the Black System event against the requirements of the Rules. This includes reviewing material gathered and reports prepared by other entities (including AEMO) to determine whether those involved satisfied all applicable obligations.

We are also conducting a targeted assessment of potential compliance issues associated with the 1 December 2016 event.

2.4.1 Black System Compliance Review

The areas of focus for our investigation of the Black System event include, but are not limited to:

1. PRE-EVENT – the AER is reviewing AEMO and ElectraNet's actions during the lead up to the storm event, including adequacy of existing processes and procedures for undertaking assessments of the risk to equipment and/or power system security.

2. EVENT – the AER is reviewing whether equipment, including that of relevant wind farms, complied with performance standards required under the Rules.

3. SYSTEM RESTORATION – The AER is reviewing the arrangements in place to facilitate system restoration after a black system event. This includes reviewing the causes of issues experienced by system restart ancillary service providers and participants' compliance with AEMO instructions during the restoration period more broadly.

4. MARKET SUSPENSION – given that the duration of the market suspension was longer than was contemplated during the design stage of the suspension arrangements, the AER is looking closely at this area and its impacts.

We are predominantly assessing participants' compliance with power system security obligations under Chapter 4 of the Electricity Rules and market operation requirements under Chapter 3.

Activities to date

We have held face to face meetings with market participants operating in South Australia and AEMO. We have requested and are currently reviewing records and evidence from AEMO and market participants on a range of issues including pre-event preparation, generator performance standards, market directions, System Restart Ancillary Services (SRAS) and Black System procedures.

We are coordinating our review closely with other energy market bodies and state regulators, including the SA Essential Services Commission and the South Australian Office of the Technical Regulator.

2.4.2 December Separation Event Compliance Review

We are also investigating the cause of the event and issues associated with power system security and operation of the South Australian market during its islanded condition on 1 December 2016.

Timelines

Exact timing will be influenced by our investigation process as well as the availability of required performance and test results and reports prepared by others. We will publish a report at the conclusion of each investigation and this will address issues where we are satisfied no further enforcement action is warranted.

Where our investigations identify issues of non-compliance this may result in us taking enforcement action. Whilst any action will be dealt with as expeditiously as possible, the nature of such action means we cannot comment publicly until we have formed a view as to whether the Rules have been contravened and it may not be possible to finalise any report until an enforcement resolution is agreed or we have decided to institute proceedings in Court.

2.5 Compliance with Dispatch Instructions

Pricing, system security and the overall integrity of central dispatch all rely on market participants accurately representing their capabilities and following AEMO's dispatch instructions. Clause 4.9.8 of the Electricity Rules outlines the general responsibilities of registered participants in relation to dispatch instructions. There are two key requirements:

- that participants comply with dispatch instructions issued by AEMO[37]; and
- that participant offers and bids represent the capability of their equipment, such that the offers and bids can be complied with at all times[38].

Compliance with the requirements of clause 4.9.8 of the Electricity Rules is a priority area for the AER. During the December 2016 quarter we resolved three matters in relation to compliance with dispatch instructions that occurred during high price events on 13 and 14 January 2016.

On 13 January 2016, the spot price exceeded $5000/MWh for the 3.30 pm and 4 pm trading intervals in Victoria and the 4 pm trading interval in South Australia. On 14 January 2016, the spot price exceeded $5000/MWh at the 2 pm trading interval in New South Wales. We published reports on these events[39].

In assessing these events, we observed that the following generating units were non-compliant with dispatch instructions on 13 January 2016.

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37 Electricity Rules, clause 4.9.8(a).

38 Electricity Rules, clause 4.9.8(b)-(e).

39 Available on the AER website at http://www.aer.gov.au/wholesale-markets/market-performance/prices-above-5000-mwh-13-january-2016-sa-vic/ and http://www.aer.gov.au/wholesale-markets/market-performance/prices-above-5000-mwh-14-january-2016-nsw/.

- Somerton Power Station's scheduled generating unit AGLSOM. Somerton is a fast start gas fired plant located in Victoria and owned and operated by AGL[40].

- Yallourn Power Station's scheduled generating unit YWPS1. Yallourn is a coal fired plant located in Victoria and owned and operated by EnergyAustralia[41].

- Hallett Power Station's scheduled generating unit AGLHAL. The station is located in South Australia and consists of twelve gas/diesel turbine units owned and operated by EnergyAustralia[42].

We also observed that the two scheduled generating units (MP1 and MP2) at the Mount Piper Power Station were non-compliant with dispatch instructions both during and in the lead-up to the high price event in New South Wales on 14 January 2016. Mount Piper is a baseload coal fired plant owned and operated by EnergyAustralia.

Our reviews of these incidents are summarised below.

2.5.1 AGL's Operation of Somerton Power Station

During the high price events in Victoria and South Australia on 13 January 2016, the Somerton scheduled generating unit was initially offline and was subsequently given instructions by AEMO to come online and commence generating. However, the Somerton unit failed to do so for four consecutive dispatch intervals.

This failure to respond to an instruction from AEMO raised concerns about the appropriateness of Somerton's fast start inflexibility profile (FSIP). The FSIP mechanism allows market participants with fast start plant (such as gas turbine generators) to provide AEMO with additional dispatch limitation information as part of their generation dispatch offer.[43] If the information is provided, AEMO must endeavour to dispatch the generator within these technical capabilities. It is therefore important that participants ensure that their generators comply with the FSIP profile and that the FSIP profile reflects the capability of the plant at the time of dispatch. Otherwise, participants risk being in breach of their requirements under clause 4.9.8 of the Electricity Rules.

We have reviewed Somerton's compliance with dispatch instructions during the high price event of 13 January 2016. We have found that Somerton failed to come online and start generating when instructed by AEMO. This was due to the following factors.

Firstly, a longstanding error in AGL's bidding systems meant that an incorrect FSIP profile was included in the generation dispatch offer for the scheduled generating unit. This resulted in AEMO receiving a FSIP T1 time of 1 minute for Somerton, instead of 5 minutes as AGL

40 Specifically, the Somerton scheduled generating unit is owned and operated by AGL Hydro Partnership.

41 Specifically, Yallourn unit 1 scheduled generating unit is owned and operated by EnergyAustralia Yallourn Pty Ltd.

42 Specifically, the Hallett scheduled generating unit is owned and operated by EnergyAustralia Pty Ltd.

43 This mechanism is used to inform the dispatch process of minimum start, stop and run times, and of minimum safe operating levels. The FSIP parameters are time to synchronise (T1), time to come to minimum load (T2), minimum time at which the plant has to operate at minimum load (T3) and minimum load level (T4). See Electricity Rules, clause 3.8.19(e).

had intended[44]. The mismatch of information meant that Somerton was unable to comply with dispatch instructions within the timeframe stipulated.

Secondly, after receiving AEMO instructions to come online, Somerton continued to remain offline for a number of dispatch intervals. This was despite receiving dispatch instructions to generate for those intervals. While this delay can partially be attributed to the mismatch of information described above, it was prolonged by misunderstandings between the trading and operational AGL staff regarding the company's internal procedures for starting the Somerton generating unit.

Review Outcomes

AGL acknowledged that it had failed to follow dispatch targets and took proactive steps to lower the likelihood of similar instances of non-compliance occurring in future. In particular, AGL:

- undertook testing to determine the appropriate FSIP profile for Somerton;
- amended its internal procedures to ensure:
  - FSIP profiles used in generation dispatch offers are checked by traders;
  - both traders and unit operators are simultaneously informed of AEMO instructions to start generating; and
  - that relevant staff are clear that Somerton should be started in accordance with dispatch instructions from AEMO;
- introduced system alarms whenever Somerton is instructed by AEMO to come online and generate; and
- amended its processes to improve communications between traders and unit operators and required the latter to undertake additional compliance training.

In determining our enforcement approach we took into account AGL's cooperation and the actions it had undertook in response to our review. This was considered against the seriousness of the breach, in particular against AGL's failure to identify and resolve the issue for a prolonged period of time.

We considered it was appropriate to issue one infringement notice to AGL. The notice was for an alleged failure to ensure that the Somerton generating unit complied with its latest generation dispatch offer for the 3.30 pm trading interval on 13 January 2016. This was considered more appropriate than an infringement notice for an alleged failure to follow dispatch instructions because the failure to comply was on the basis of having inadequate systems, processes and procedures in place to ensure an appropriate generation dispatch offer. AGL paid its infringement penalty of $20 000 on 3 January 2017.

44 This is the time taken for the unit to synchronise and be ready to generate.

2.5.2 EnergyAustralia's Operation of Yallourn and Hallett Power Stations

During the high price events in Victoria and South Australia on 13 January 2016, two scheduled generating units, owned and operated by EnergyAustralia (Yallourn unit 1 and Hallett), substantially deviated from their dispatch instructions across several dispatch intervals.

Yallourn Power Station

Our compliance review identified that at the start of the 3.30 pm trading interval, Yallourn unit 1 was experiencing coal mill issues which reduced its maximum output. This reduction in availability was reflected in a rebid and consequently the unit was given instructions to reduce output.

Approximately midway through the 3:30 pm trading interval, the dispatch price reached the market price cap. In consultation with its traders, EnergyAustralia's operators subsequently increased the output of the Yallourn unit. It continued to increase throughout the 3:30 pm trading interval, ultimately exceeding its dispatch targets and the maximum availability of the unit (as indicated in its latest dispatch offer).

EnergyAustralia did place rebids to increase the maximum availability of the Yallourn unit (consistent with discussions between its traders and unit operators). However, these rebids did not take effect until the end of the trading interval.

Hallett Power Station

During the 3:30 pm trading interval on 13 January 2016, Hallett Power Station's scheduled generating unit AGLHAL initially failed to come online and generate in response to AEMO instructions. EnergyAustralia's traders failed to notice AEMO's signal to prepare the unit for dispatch (as they were focused on market events in Victoria), as did onsite unit operators. Hallett came online when its unit operators informed the trading desk that Hallett had received a start instruction.

Following this, there was a discussion between the traders and unit operators regarding the number of individual turbine units to bring online at Hallett[45]. In that discussion the traders requested the unit operators to bring as many of the turbine units on as possible and to notify the trading team once more units were online. During the 3.50 pm dispatch interval, one of the unit operators called the trading desk to inform them that Hallett could generate more than the current dispatch target. The traders then confirmed what the maximum capability of Hallett was and requested that operators continue increasing its output toward that capability, indicating that they would rebid Hallett to follow the increased output. As a result, Hallett ended the 3.50 pm dispatch interval generating well above its dispatch target. A rebid was placed by EnergyAustralia shortly before the end of the 3.50 pm dispatch

45 As outlined earlier in this report, Hallett is an aggregated unit which consists of twelve individual small diesel/gas turbine units.

interval (rebidding more capacity to lower price bands) but this did not come into effect until the next dispatch interval[46].

Review Outcomes

EnergyAustralia has taken steps to improve its processes, procedures and systems to ensure that similar incidents at Yallourn and Hallett do not occur in future. Specifically, it:

- updated its training and procedures to reinforce that unit operators should operate to follow dispatch targets;
- installed new alarms at Yallourn to notify its operators when the unit is deviating from its dispatch target; and
- installed the following alert processes at Hallett:
    - audible alarm in the control room when start signal received;
    - MS alarm to Traders when start signal received;
    - SMS alarm to Standby Operators (switched on after hours) when Hallett start signal is received; and
    - SMS notifications to the Trader and Standby Operator notifying of dispatch targets.

EnergyAustralia also acknowledged that some discussions between its traders and unit operators during the high price events appeared to be inconsistent with its training and procedures.

We consider that this was a serious failure of EnergyAustralia's processes, procedures and systems to ensure that its generating units follow their dispatch targets. In particular, while participants are able to rebid their generation offers close to dispatch, it is important that traders and unit operators continue to follow AEMO's dispatch instructions and not pre-empt the dispatch targets that a generating unit may receive once a rebid becomes effective.

In determining our enforcement approach we took into account EnergyAustralia's cooperation during the review and the proactive steps it had taken to improve its systems, processes and procedures.

We considered it appropriate to issue two infringement notices to EnergyAustralia for alleged failures (at Yallourn unit 1 and Hallett) to follow dispatch instructions. Specifically, infringement notices were issued for the dispatch intervals where Yallourn unit 1 and Hallett over-generated the most relative to their dispatch target.

We imposed total infringement penalties of $40 000. EnergyAustralia paid this amount on 22 December 2016.

46 Note that in the 4pm trading interval, the dispatch price in South Australia exceeded $10 000/MWh across the first three dispatch intervals.

2.5.3 EnergyAustralia's Operation of Mount Piper Power Station

On 14 January 2016, a high price event occurred in New South Wales during the 2 pm trading interval. The AER investigated this event and identified that the Mount Piper Power Station's two scheduled generating units (MP1 and MP2) were non-compliant with dispatch instructions between the 1 pm and 2 pm trading intervals. In particular, MP1 over-generated for 11 out of 12 dispatch intervals between 12:45 pm and 13:40 pm. Conversely, MP2 under-generated (relative to its dispatch targets) for the majority of the dispatch intervals between 12:35 pm and 2 pm.

Our review of the performance of the Mount Piper units identified that, in the lead up to the event, the turbines of MP1 and MP2 had suffered extensive deposits and erosion. This compromised the interactions between the unit's digital control systems and the automatic generation control system (AGC) used by AEMO[47]. When the output of the units exceeded a certain megawatt threshold the digital control system would cause the units to under-generate compared to the dispatch signals sent via the AGC. We understand that this particularly affected MP1.

In addition to this, the custom of Mount Piper's unit operators was to set daily availability based on the maximum megawatt output that the plant was expected to be capable of (based on current plant conditions) and then operate to avoid non-conformances. This meant that, despite some sustained periods of unit under-generation (due to the unit being unable to sustain output at the maximum availability advised to AEMO), a rebid would not be submitted.

A broader review of the performance of the Mount Piper generating units on the 14 January 2016 also identified other sustained periods of under-generation relative to dispatch targets. It is understood that EnergyAustralia no longer operates its units in such a manner. EnergyAustralia advised of a shutdown of MP1 in late 2016 to clean and repair its turbines. This has resolved the problem described above. Similar maintenance and repair works are planned for MP2 in the third quarter of 2017.

Review Outcomes

EnergyAustralia co-operated with the AER during our review and has taken the following steps to improve its processes, systems and procedures.

- Organising meetings between the trading team and the Mount Piper unit operators to ensure there is a common understanding of plant capacity and plant capability and the impacts of not following targets.
- Installing viewers for both the trading team and operators so that they can see if they are not following targets in real time.

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47 The digital control systems control unit output. AEMO uses its automatic generation control system (AGC) to monitor system frequency and send control signals to generators to ensure that frequency is maintained within normal operating bands. Usually, the digital control systems direct output to match the AGC signals sent by AEMO.

- Tracking the daily performance of all EnergyAustralia assets and reporting to EnergyAustralia's senior management.

- Recalibrating the unit control systems to account for the current level of unit performance (prior to the maintenance and repair works on MP1).

- Implementing processes to monitor and report on the performance of MP1 and MP2 against dispatch instructions (following its maintenance and repair works). Where material deviations from dispatch targets are identified, EnergyAustralia will investigate and take steps to correct the problem.

- Updated operator training and procedures to reinforce that unit operators should operate to follow dispatch targets.

A further concern that we identified was that the Mount Piper units did not appear to be capable, at times, of reaching the maximum availability indicated in their latest generation dispatch offer. In particular, the historical operating practice was to set maximum availability based on the maximum output the units were capable of reaching under current plant conditions, rather than the output the units were capable of reaching consistently. Clause 4.9.8(b) of the Electricity Rules requires that the scheduled generating units must be able to comply *at all times* (emphasis added) with their latest generation dispatch offer. Thus, it is not enough that a generating unit be capable of just reaching their offered maximum availability occasionally. A unit must be able to do so at all times while the offer is in effect. Where a unit's physical capability changes, this ought to be rebid as soon as practicable.

EnergyAustralia has agreed to an administrative resolution via a voluntary reporting arrangement. Under this arrangement, EnergyAustralia will provide the AER with a monthly report on the compliance with dispatch instructions of both Mount Piper units. The reporting is for a six month period, with an additional four month reporting period for MP2 once its maintenance and repair works are complete.

We are satisfied that the steps taken by EnergyAustralia, including the voluntary reporting arrangement, should be sufficient to address the performance problems at the Mount Piper plant and ensure that they are capable of complying with their offered maximum availability at all times the offer is in effect. On this basis, we do not propose to take any further action given the level of cooperation and other action taken. We will continue to monitor Mount Piper's compliance with dispatch instructions.

2.6 TransGrid Proposed Second Supply to ACT

In April 2016, TransGrid approached the AER regarding whether it was required to apply the regulatory investment test for transmission (RIT-T) to its proposed Stockdill Drive project[48]. TransGrid proposed the project to address its ACT transmission licence requirements. The

48 The RIT-T is a cost-benefit test published by the AER in 2010 in accordance with the requirements of the Electricity Rules. Transmission businesses are required[48] to apply the RIT-T prior to undertaking any capital investment in their network above $6 million.[48] The RIT-T requires transmission businesses to assess all network and non-network credible options to address the investment need and identify the credible option which has the highest net economic benefit (the preferred option). When applying the RIT-T, transmission businesses are also required to follow the RIT-T stakeholder consultation processes set out in the Electricity Rules.

license requires Transgrid to have two independent sources of supply for the ACT, by 2020, in case of a special contingency event.

The Stockdill Drive project was developed by TransGrid in conjunction with the ACT Government in 2014-15 to address requirements in the ACT Electricity Transmission Supply Code (Supply Code). Specifically, the Supply Code requires that, from 31 December 2020, TransGrid must be capable of providing continuous electricity supply at 375 MVA to the ACT 132 kV network immediately following the unexpected disconnection of one point of transmission supply[49].

The ACT 132 kV network currently has one point of transmission supply. Thus, this licence condition requirement requires TransGrid to either build a second point of transmission supply into the ACT 132 kV network or put in a non-network option (e.g. a large generator) capable of maintaining continuous electricity supply in the event of disconnection of the other point of transmission supply.

In 2009, TransGrid conducted a regulatory test (the predecessor to the RIT-T) to identify the least cost option to meet the ACT reliability requirements at the time. These reliability requirements were similar to the current requirements in the Supply Code. The regulatory test assessment found the development of a switching station at Wallaroo (the Wallaroo project) to be the least cost option.

In April 2016 TransGrid informed us that it was unable to implement the Wallaroo option as it could not obtain the necessary easements within the ACT. Transgrid also informed us that both it and the ACT Government had agreed to proceed with the Stockdill Drive option. On 21 November 2016, we wrote to Transgrid stating that a RIT-T was unlikely to identify a viable alternative option given ACT reliability requirements and the difficulty of obtaining easements in the ACT.

Transgrid's Revenue Requirements

In reviewing the Transgrid case, we also found that the events leading up to the cancellation of the Wallaroo project and the development of the Stockdill Drive project occurred largely in parallel with the revenue determination process for TransGrid's 2015-18 regulatory control period. In its revenue proposal for the 2015-18 revenue period, TransGrid included the $31.4 million ($2013-14) cost of the Wallaroo project in its capital expenditure proposal on the basis that this was required to meet ACT reliability requirements[50]. In its draft revenue determination for TransGrid's 2015-18 regulatory control period, (published 27 November 2014) the AER accepted the costs of the Wallaroo project as forming part of TransGrid's capital expenditure requirements for the period.

Prior to the AER's final determination TransGrid and the ACT Government agreed to proceed with the Stockdill Drive project instead of the Wallaroo project. To accommodate this change, the ACT reliability requirements were revised with the introduction of the Supply Code. This postponed the required date of the Stockdill Drive project to 31 December 2020,

49 Clause 4.1.1, ACT Electricity Transmission Supply Code 2016 (Disallowable instrument DI2016-189), available at: http://www.legislation.act.gov.au/di/2016-189/current/pdf/2016-189.pdf.

50 Similar to the current Supply Code requirements commencing from July 2016.

thus deferring the need for the project until the 2018-23 regulatory control period. This decision was confirmed in a letter from the ACT Government to TransGrid in March 2015. Our final revenue decision for TransGrid's 2015-18 regulatory control period was published the following month (on 31 April 2015).

Although these revisions preceded our final revenue decision, TransGrid did not alert us to these changes. As a result, the costs of the Wallaroo project remained included in TransGrid's revenue requirements for the 2015-18 regulatory control period. This earned TransGrid an additional allowance for that period.

We consider that there was sufficient time, before the publication of its final decision, for TransGrid to alert us to these changes. This would have enabled us to incorporate the changed circumstances into our final determination on TransGrid's revenue requirements for 2015-18.

In its revenue proposal for the 2018-23 regulatory control period TransGrid is seeking an allowance of $37.4 million ($ June 2018) for the Stockdill project. TransGrid is not seeking the deferral value of the Stockdill Drive project under its Capital Expenditure Sharing Scheme[51] arrangements in the 2018-23 regulatory control period for the underspent capital.[52]

In summary, the AER's compliance review, regarding the potential application of a RIT-T to the Stockdill project, revealed that we were not made aware of the project's deferral (from the 2015-18 to the 2018-2023 regulatory control period) during the 2015-18 revenue determination. This outcome is not reflective of good regulatory practice. If a TNSP becomes aware of a material change in a project (i.e. deferral or step change in costs) which forms part of a revenue proposal which is currently being considered by the AER, we would encourage them to notify us so changes can be accounted for as part of the revenue determination.

Further, we will examine our own processes, including our engagement with jurisdictional planning processes to guard against future occurrences of these types of information gaps.

2.7 Powercor Breach of MSATS Procedures

In October 2016, AEMO notified the AER, in accordance with clause 7.2.8(f) of the National Electricity Rules, that it considered that Powercor was in breach of its obligations under clause 2.4(t) of the Market Settlement and Transfer Solution (MSATS) Procedures, due to its failure to correct cross border supply information in the MSATS following requests by AEMO. A breach of the MSATS Procedures is a breach of clause 7.2.8(d) of the Electricity Rules.

51 The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capex becomes more efficient and financial penalties for those that become less efficient.

52 Under the CESS a service provider retains 30 per cent of the cumulative underspend or overspend, while consumers retain 70 per cent of the cumulative underspend or overspend. This is calculated after taking into account the financing benefit or cost to the service provider of the underspends or overspends and whether any adjustments are made to account for deferral of capex and ex post exclusions of capex from the regulatory asset base.

Following AEMO’s notification of the matter, we engaged with Powercor to ensure that it undertook appropriate measures to ensure compliance with the MSATS Procedures and so ensure compliance with clause 7.2.8(d) of the Electricity Rules. In November 2016, Powercor advised that it had rectified the issue and confirmed that all relevant data had been corrected and that the supply information recorded by Powercor in MSATS met the requirements of clause 2.4(t) of the MSATS Procedures. Powercor also advised that both it and CitiPower and had initiated a review to confirm if there are other changes required to Transmission Node Identifier data, and undertook to work co-operatively with AEMO to undertake any corrections.

While Powercor had rectified NMI standing data related to wholesale cross-border supplies prior to the AEMO notification to the AER, and promptly rectified the retail NMI data issues following AEMO’s notification to the AER, this resolution did take several months to complete. This situation highlights the importance of participants responding promptly to AEMO’s requests for rectification of MSATS data. The AER expects that all participants will proactively ensure compliance with the MSATS Procedures, updating MSATS information in a timely way, and respond promptly if AEMO indicates that remediation is required.

2.8 Participant Preparations for Competition in Metering and Related Services (‘Power of Choice’)

From 1 December 2017, amendments to the Electricity Rules will facilitate customers taking up advanced metering through the introduction of a new category of registered participant, ‘Metering Coordinator’. Retailers will be required to appoint a Metering Coordinator for their customers and large customers will have the option of appointing their own Metering Coordinator. The Metering Coordinator will take on the role that is currently performed by the ‘Responsible Person’ under Chapter 7 of the Electricity Rules.

Ensuring participant readiness for the ‘Power of Choice’ (POC) metering rule changes is a priority for the AER during 2017. We note that a significant number of affected participants are participating in AEMO’s POC Implementation Program. A key feature of AEMO’s program is monthly industry readiness reporting which has been in place since November 2016. While reporting is voluntary, we encourage all affected participants to report regularly to AEMO on their readiness, and will be contacting affected participants that are not currently participating in the readiness reporting program to discuss what preparations they have undertaken.

In determining whether to take enforcement action for non-compliance with Chapter 7 metering requirements from 1 December 2017, and the nature of any enforcement action, a relevant factor for the AER (in addition to the factors listed in our Statement of Approach) will be whether the participant has participated in AEMO’s POC Implementation Program, made bona fide efforts to prepare for the changes, and provided early and frank disclosure on their readiness through the reporting mechanism established by AEMO.

During 2017, we will be examining participant compliance with a range of metering obligations, in Chapter 7 of the Electricity Rules, to facilitate a smooth transition to metering contestability. This process will commence in March 2017 with a targeted compliance review of participant compliance with obligations to install different meter types according to customer consumption, and ensure that the meter is upgraded where consumption increases beyond the relevant thresholds in the Electricity Rules.

2.9 Jurisdictional derogations

Chapter 9 derogations exempt Victorian smelter traders, 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; and
- 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.

In November 2016, the State Electricity Commission of Victoria (SECV) advised the AER of the expiry of the Electricity Supply Agreements for the Portland Aluminium Smelter from 31 October 2016.