RULE CHANGE

Australian Energy Market Commission

FINAL RULE DETERMINATION

National Gas Amendment (Gas day harmonisation) Rule 2017

Rule Proponent

COAG Energy Council

16 February 2017

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About the AEMC

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

Summary

The Australian Energy Market Commission (AEMC or Commission) has made a final rule, which is a more preferable rule, to harmonise the start time of the gas day used in the short term trading market hubs and the gas supply hub trading locations with the gas day start time used in the Victorian declared wholesale gas market. Under the final rule, the gas day in each market at each location will start at 6.00 am Australian Eastern Standard Time (AEST) from 1 April 2021.

The different facilitated east coast gas markets currently operate with different gas day start times as a result of legacy pipeline arrangements. A 'gas day' is the period of 24 consecutive hours over which, among other things, certain operational, commercial and market activities (including intra-day activities) occur in each of the facilitated markets. While pipeline operators and shippers have operational and commercial arrangements in place to manage the differences in gas day start times for participants operating in multiple markets, these are not costless.

Providing a common gas day across these different market locations under the National Gas Rules is expected to lower the cost of these arrangements and support the current developments occurring in the east coast gas market. The current developments include the availability of multi-asset gas transport agreements and short term capacity trading services from pipeline operators. However, if the rule was to commence in the near term, while these services would be less costly to provide, the benefits would be limited and are unlikely to outweigh the implementation costs.

Although the near term benefits would be limited, a harmonised gas day is expected to be beneficial for the future development of the new market arrangements identified in the AEMC's east coast gas review which have been accepted by the COAG Energy Council and are currently being progressed by the Gas Market Reform Group. Specifically, a harmonised gas day will complement capacity standardisation and assist the introduction of an exchange-based wholesale trading market and a short term pipeline capacity trading framework. Stakeholders expressed support for a common gas day in the context of making these reforms. By implementing a harmonised gas day in conjunction with capacity standardisation and trading reforms, the Commission expects that the benefits will exceed the implementation costs.

Under the current reform program set out by the COAG Energy Council, the development of the east coast gas market to incorporate capacity standardisation and short term secondary pipeline capacity trading and auctions is expected to be completed by approximately mid-2021. In addition, advice from stakeholders indicates that in general April is likely to be a suitable period to implement a change to the gas day for the facilitated markets given the seasonality of load patterns in the gas markets in New South Wales and South Australia. Accordingly, the Commission has made 1 April 2021 the commencement date of the final rule so that changes to the gas day can be implemented at the appropriate time of year and coordinated with the other market changes.

Aligning the short term trading market and the gas supply hub gas day start times to 6.00 am AEST as used in the Victorian declared wholesale gas market was found to be the optimal option for achieving market harmonisation. The morning peak gas demand

in Victoria makes 6.00 am AEST the most appropriate gas day start time from an operational and market perspective in Victoria. The Commission concluded that the detrimental operational implications on the Declared Transmission System and the market pricing effects on the Victorian declared wholesale gas market will outweigh the benefits of introducing an 8.00 am AEST gas day start time as favoured by some Queensland market participants. This outcome is also likely to be the case under the new exchange-based wholesale trading market to be designed by the Gas Market Reform Group.

Background

The final rule has been made in response to a rule change request submitted by the COAG Energy Council. The rule change request sought to amend the National Gas Rules to harmonise the gas day start times of all short term trading market hubs with the Victorian declared wholesale gas market gas day start time of 6.00 am AEST. In addition, the COAG Energy Council proposed to insert new rules into the National Gas Rules to specify that the gas day to be used in the gas supply hub exchange agreement would also commence at 6.00 am AEST.

The rule change request arose from stage 1 of the AEMC's east coast wholesale gas market and pipeline frameworks review in which the Commission recommended the COAG Energy Council submit a rule change request to harmonise the gas day start time of the short term trading market hubs and the gas supply hub trading locations with the Victorian declared wholesale gas market. It was suggested that such a change would reduce compliance costs and barriers to trading across multiple locations, and would therefore be likely to promote the national gas objective.

The final rule

Consistent with the COAG Energy Council's rule change request, and the Commission's draft rule, the Commission has made a final rule to amend the definition of gas day in the National Gas Rules so that the short term trading market gas day is a period of 24 consecutive hours beginning at 6.00 am AEST on each day.

In addition, the Commission has determined that a new rule (which was not included in the proposed rule) be introduced to provide certainty that gas allocation information provided to the Australian Energy Market Operator in relation to the short term trading market is determined using measurements corresponding to the market's gas day. This final rule requires allocation data provided by allocation agents for short term trading market facility operators to be derived using metering data based on the new gas day. It will apply to the measurement of both deliveries to, and withdrawals from, a short term trading market hub. This new rule also provides greater certainty that the final rule would trigger 'change of law' provisions in contracts to allow pipeline operators to pass through certain costs associated with the change in the market's gas day start time.

The Commission has made a final rule to give effect to a change in the gas day start time for the gas supply hub by a new rule requiring that the exchange agreement must define a gas day as a period of 24 consecutive hours beginning at 6.00 am AEST. The exchange agreement must also specify the period for delivery, supply or acceptance of goods or services offered for trading on the gas trading exchange by reference to one or more whole gas days or (where that period is shorter than one gas day) part of a gas day.

Together, the Commission considers that these amendments under the final rule, which are to commence on 1 April 2021, are likely to:

- reduce the cost and complexities that market participants operating (or wishing to operate) across multiple facilitated market locations currently face, including pipeline operators located at the interface of markets with different gas days
- provide for a greater degree of interoperability and interconnection between the markets and, in doing so, promote participation and liquidity in these markets and trade between locations.

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1 COAG Energy Council's rule change request

1.1 The rule change request

On 26 November 2015, the Council of Australian Governments (COAG) Energy Council submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) that seeks to harmonise the gas day start times used in the short term trading market (STTM) hubs and the gas supply hub (GSH) trading locations with the gas day start time used in the Victorian declared wholesale gas market (DWGM). Under the proposed rule, the gas day in each market at each location would commence at 6.00 am Australian Eastern Standard Time (AEST).

1.2 Current arrangements

1.2.1 Different gas day start times across the facilitated markets

The gas industry on the east coast of Australia is undergoing a structural change. A collection of largely isolated point-to-point pipelines has gradually evolved into a more interconnected network which supports a series of increasingly interlinked markets. The emergence of a Liquefied Natural Gas (LNG) industry in Queensland is contributing towards changing market dynamics and creating opportunities for the trading of gas. Queensland LNG is being sold into international markets under contract prices linked to international oil prices. The influence of these pricing structures is being felt in the Australian gas market, resulting in a shift in domestic demand and consequential impacts on patterns of gas flows across the pipelines.

Despite the extensive development in infrastructure that has occurred and the ongoing reforms in the sector, the eastern gas market and regulatory frameworks appear fragmented.[1] For example, there are three different facilitated market designs in eastern Australia: the DWGM in Victoria, the STTM with hubs at Adelaide, Sydney and Brisbane, and the GSH with trading locations at Wallumbilla and Moomba. The different markets were designed in response to different, specific circumstances and feature different sets of regulatory arrangements. The markets supplement bilateral contracts between gas producers and shippers and pipeline operators and shippers. They provide additional options for trading and managing risks.[2]

The different facilitated markets currently operate with different gas day start times as a result of legacy pipeline arrangements. A ‘gas day’ is the period of 24 consecutive hours over which, among other things, certain operational, commercial and market activities (including intra-day activities) occur in each of the facilitated markets:[3]

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1 AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 2.

2 For further information on the design and operation of the STTM, the DWGM and the GSH refer to appendices E, F and G respectively in the AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015.

3 A gas day is specifically defined under rule 200 of the National Gas Rules (NGR) in respect of the DWGM, rule 364 of the NGR in respect of the STTM. The gas day start time for the GSH is currently specified in the Gas Supply Hub exchange agreement.

- The Victorian DWGM gas day commences at 6.00 am AEST.
- The Sydney and Adelaide STTM and the Moomba GSH gas days commence at 6.30 am AEST.
- The Brisbane STTM and Wallumbilla GSH gas days commence at 8.00 am AEST.

Market time is always measured in AEST in each of these markets regardless of daylight savings time.[4] Figure 1.1 illustrates the different gas day start times that are currently used in each of the east coast markets and the underlying pipeline gas day arrangements.

4 Rule 366 of the NGR and clause 2.7 of the exchange agreement.

Figure 1.1 Gas day start times in the facilitated markets

Source: AEMC

1.2.2 The gas day in the STTM

The STTM was designed as a mandatory market for wholesale trading and balancing of gas at defined demand hubs between transmission and distribution pipelines. The STTM hubs are located at Sydney, Adelaide and Brisbane. Each hub operates separately under the same regulatory framework.

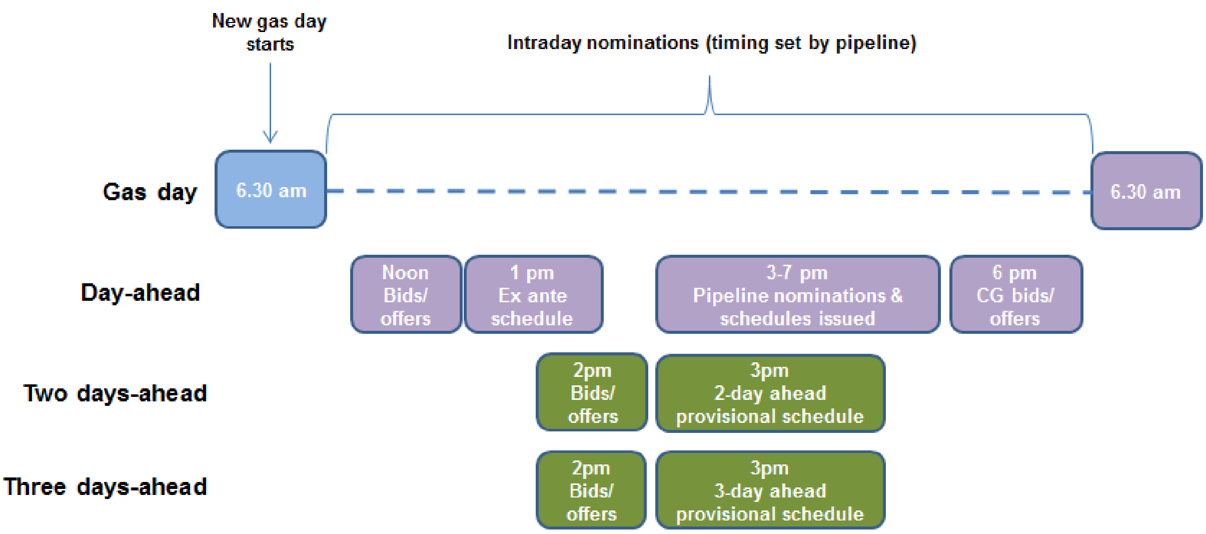
The balancing and scheduling process takes place each gas day at each hub. Prices in each hub in the STTM are set and change each gas day. The gas day is also used for the operation of the STTM, for example to:

1. set the time by which information must be provided to the market
2. structure information provided to the market about capacity rights, trading rights, bids and offers
3. structure information provided by AEMO to participants such as schedules.

In other words, the gas day defines the 24 hour pricing, scheduling and balancing period for the STTM. However, due to the different start times at the different hubs, the outcome in practice is that activities occur at different times of the day. For example, rule 410 in the NGR requires ex ante bids and offers to be made no later than 5.5 hours after the start of the gas day that precedes the gas day to which the bid or offer relates. In practice this means that offers and bids can be submitted to AEMO up to 12.00 pm AEST the day before the relevant gas day in Sydney and Adelaide, and up until 1.30 pm AEST in Brisbane.

While independent of the STTM, pipeline nominations are also made by reference to a gas day start time. After the ex ante market schedules are published by AEMO shippers make nominations to pipeline operators in accordance with their relevant contracts.[5]

Figure 1.2 The gas day in the Adelaide and Sydney STTM hubs



Source: AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 draft report, 7 May 2015, p. 215.

5 AEMO, *Industry guide to the STTM*, November 2015, p. 35.

1.2.3 The gas day in the GSH

The Wallumbilla GSH was established in early 2014, and the Moomba GSH in June 2016. The GSH framework was developed to enhance transparency and reliability of gas supply by creating a voluntary market that offers a low-cost, flexible method to buy and sell gas at interconnecting pipelines.[6] The GSH is an exchange for the wholesale trading of natural gas. Participants may place anonymous offers (to sell) or bids (to buy) a specified quantity at a specified price which are automatically matched on the exchange to form transactions during the trading hours of 9.00 am to 5.00 pm by AEMO. Once matched, parties then finalise their transaction.[7]

The primary instrument governing the operation of the GSH is the GSH exchange agreement.[8] In accordance with the NGR, the exchange agreement sets out the standardised terms of participation in the GSH and the terms governing transactions entered into through the exchange. The exchange agreement contains the trading, delivery and settlement obligations common to all products available at the supply hub. It also outlines the product specifications, which are schedules to the exchange agreement that contain details unique to each product.

Under the exchange agreement, the primary function of the gas day is to define the delivery period for products sold through the exchange. The delivery period can cover one, several or part of a gas day. The gas day is also used to define and measure compliance with delivery obligations. Delivered quantities must be reported for each gas day and imbalances are calculated for each gas day using that information. For example, for a product with a delivery period of seven gas days, the contract quantity must be delivered each gas day. Delivery is measured each gas day and an imbalance may lead to an imbalance charge for that gas day.

1.2.4 The gas day in the Victorian DWGM

The DWGM, established by the Victorian Government in March 1999, is a compulsory market in which Victorian gas market participants sell or purchase gas. Initially, a gas day start time of 9.00 am was used in the DWGM. The gas day start time was subsequently changed to 6.00 am AEST in 2007 in response to a 2003-04 review, also known as the Pricing and Balancing Review.[9] The new gas day start time was selected

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6 http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub, viewed 9 November 2016.

7 Participants may also agree bilaterally to a transaction on standard product terms and then register the transaction for delivery and settlement.

8 The exchange agreement is a multilateral contract between AEMO and hub participants which may be amended by AEMO in accordance with the NGR and the exchange agreement. Rule 540 of the NGR sets out the process pursuant to which AEMO may amend the exchange agreement. AEMO may only amend the exchange agreement if it is satisfied the amendment is consistent with the NGL and the NGR, and is appropriate having regard to the NGO and any compliance costs likely to be incurred by the operator or gas trading exchange members in consequence of the amendment. Subject to a limited exception, AEMO must undertake a consultation process with gas trading exchange members and any other affected people in respect of proposed amendments to the exchange agreement.

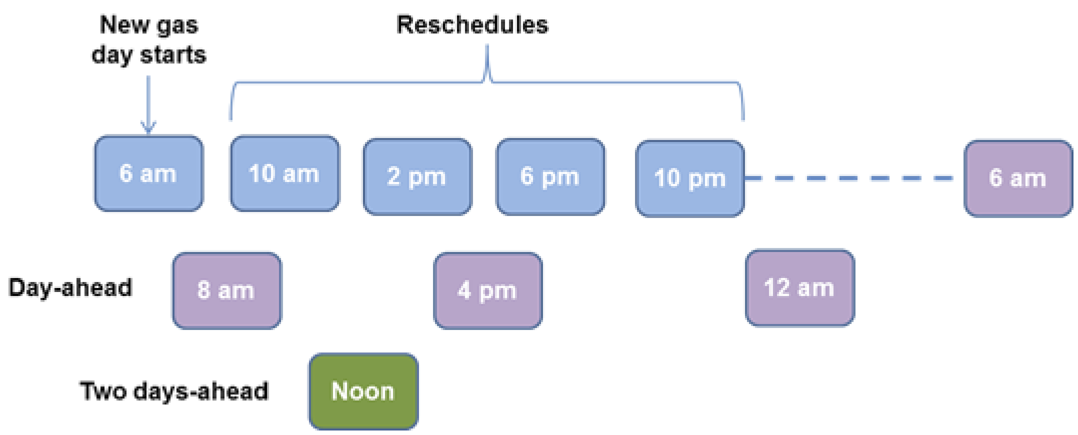
9 AEMO, *Technical guide to the Victorian Declared Wholesale Gas Market*, July 2013, p. 11.

on the basis of it being just prior to the run up to the morning customer peak and was therefore the most efficient time from a Victorian market and operational perspective.[10]

Participants bid to inject or withdraw gas from the Declared Transmission System (DTS). Prices are determined on an ex ante[11] intra-day basis where there are five scheduling times beginning at the start of the gas day at 6.00 am AEST and then followed by 10.00 am, 2.00 pm, 6.00 pm and 10.00 pm. Intra-day pricing was also introduced in 2007 in response to the Pricing and Balancing Review, allowing participants to respond to changing market conditions during the day.[12]

As the independent market and system operator, AEMO is responsible for operating both the DWGM and the DTS and balancing gas supply and demand and transportation through a centrally co-ordinated scheduling process.

Figure 1.3 The gas day in the Victorian DWGM



Source: AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 draft report, 7 May 2015, p. 235.

1.3 Rationale for rule change request

In its rule change request the COAG Energy Council asserted that different gas day start times across the facilitated markets create complexity and inconsistency between the markets which may:

- create additional costs to participants operating in these markets
- act as a barrier to gas trading and opportunities for arbitrage between different regions of the interconnected east coast market.[13]

The rule change request made a number of key points:

- The required timing for intra-day activities in the STTM are specified in the NGR relative to the start of the gas day. The inconsistent start times of the three STTM hubs result in different:

10 AEMO, submission on the consultation paper, p. 3.

11 In this context, ex ante refers to transactions that occur ahead of the relevant time period.

12 VENCorp, *Victorian gas market pricing and balancing review*, recommendations to government, 30 June 2004.

13 COAG Energy Council rule change request, 19 November 2015, p. 5.

- deadlines for the submission of bids and offers for the following gas day
- timing for the publication of ex ante schedules and pricing.[14]

- The gas day start times for each of the facilitated markets are not currently prescribed in a single national legal instrument. The gas day start times of the STTM hubs and the DWGM are prescribed in the NGR while the GSH exchange agreement specifies the gas day start time for the products offered through the Wallumbilla GSH.[15] The COAG Energy Council's view is that specifying a uniform gas day start time for the STTM hubs and the GSH in the NGR that is aligned with the DWGM gas day would provide market participants with greater certainty and confidence that the gas day start time would become and remain aligned.[16]
- Stakeholders have indicated that it is not currently possible to design a financial risk management product to fully hedge against price risk on a given day due to a number of market design factors. The COAG Energy Council views harmonising the gas day as a preliminary step towards greater harmonisation of market design which may later support the use of financial risk management products.[17]

1.4 Solution proposed in the rule change request

The rule change request from the COAG Energy Council proposed changes to the NGR to harmonise the gas day start times of the STTM and GSH with the gas day start time of the Victorian DWGM. The rule change request sought to achieve this by:

- prescribing a single gas day definition in the NGR for all STTM hubs, with a start time of 6.00 am AEST, to align the Adelaide, Sydney, and Brisbane hubs with the Victorian DWGM gas day
- inserting a new rule in the NGR that establishes the GSH gas day start time as 6.00 am AEST to harmonise the GSH gas day with the Victorian DWGM gas day.[18]

The rule change request includes drafting of the proposed rule.

1.5 Relevant background

1.5.1 East coast wholesale gas market and pipeline frameworks review

The accelerating change in the market dynamics of the east coast gas industry has led to a renewed focus on market development and supply chain efficiency. Recognising the need to increase flexibility and foster liquid trading in the east coast gas market, the

14 ibid, p. 6.

15 This approach was also subsequently applied to the Moomba trading location products.

16 ibid, pp. 6-7.

17 ibid, p. 7.

18 COAG Energy Council rule change request, 19 November 2015, p. 8.

COAG Energy Council released a vision for Australia's future gas market in December 2014:[19]

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The COAG Energy Council requested that the AEMC review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia (the east coast review). The purpose of the review was to consider the role and objectives of the existing markets on the east coast in light of the changing market dynamics and to set out a roadmap for their continued development that allows the vision to be met.[20]

The terms of reference for the east coast review requested that AEMC consider, among other things, the harmonisation of the market parameters of facilitated markets such as "prudential obligations, gas day trading times and market price caps".[21]

1.5.2 Stage 1 of the review

Stage 1 of the east coast review outlined the overall direction for the east coast market, including an overview of current market outcomes and a gap analysis between the COAG Energy Council's vision and the existing arrangements. The stage 1 final report set out the AEMC's recommendations on the focus areas for market reform to be pursued in stage 2 of the review, as well as recommendations for market enhancements and initiatives that can be progressed in the near term, including gas day harmonisation.[22]

Submissions received during stage 1 of the east coast review were supportive of the AEMC's draft finding that the gas day should be harmonised across the markets with responses ranging from cautious in principle or qualified support to full support.[23]A number of submissions suggested further work should be done to determine the costs and benefits of harmonising the gas day, implementation requirements and timetable.[24]

At the conclusion of stage 1 of the east coast review, the Commission came to the view that harmonising the three market gas day start times across the DWGM, STTM and

19 COAG Energy Council, *Australian gas market vision*, December 2014, p. 1.

20 COAG Energy Council, *East coast wholesale gas market and pipeline frameworks review*, terms of reference, 20 February 2015, p. 1.

21 ibid, p. 3.

22 AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report , 23 July 2015, pp. 113-115.

23 ibid, pp. 110-112.

24 Submissions on *East coast wholesale gas market and pipeline frameworks review*, stage 1 draft report: APA, p. 14; ESAA, pp. 4-5; Origin, p. 3.

GSH would reduce compliance costs and barriers to trading across multiple hubs, and would therefore be likely to promote the national gas objective (NGO).[25]

To achieve the policy objective of greater harmonisation, the Commission recommended that the COAG Energy Council submit a rule change request to the AEMC seeking to change the STTM gas day start times to 6.00 am AEST and define the GSH gas day start time in the NGR as 6.00 am AEST, in line with the arrangements in the DWGM.[26] In making this recommendation the Commission noted that a rule change process would allow the Commission and stakeholders to engage at a more granular level on the operational, commercial and legal work that implementation of the recommendation would require.[27]

1.5.3 Stage 2 of the review

Since initiating this rule change process on 3 March 2016, the AEMC has completed stage 2 of the east coast review. This second stage more fully developed medium and long-term adjustments required to achieve the COAG Energy Council's vision, including the transition path. In its stage 2 final report, the Commission recommended a gas market development roadmap that brought together recommendations on wholesale and transportation capacity markets, and information provision. A number of recommendations relating to the development of a liquid market for the secondary trade of pipeline capacity are of particular relevance to the gas day harmonisation rule change and can be summarised as follows:[28]

- introduce a day-ahead auction of contracted but un-nominated pipeline capacity to be conducted shortly after nomination cut-off
- standardise provisions in capacity agreements to make capacity more fungible and allow shippers greater receipt and delivery point flexibility.

The processes to implement these recommendations will need to consider the gas day start time to be used in the day-ahead auctions and standardised capacity agreements.

The Commission recommended that the COAG Energy Council establish, through an inter-governmental agreement, a dedicated gas reform group with a full-time project management office tasked with developing the package of changes to the NGL, NGR and any subordinate instruments to implement the Commission's recommended wholesale gas and pipeline capacity market reforms. The Commission envisaged that the implementation of the complete package will occur over several phases, requiring commitment to progress development of the market over the next decade.

1.5.4 Implementation of the stage 2 review recommendations

At its August 2016 meeting the COAG Energy Council endorsed the reforms recommended by the AEMC in stage 2 of the east coast review subject to further

25 AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 113.

26 ibid.

27 ibid, p. 114.

28 AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 2 final report, Chapter 5.

stakeholder consultation by the AEMC on the details of the recommendations relating to the southern hub.[29] At this meeting the COAG Energy Council announced the establishment of the Gas Market Reform Group (GMRG) which would be responsible for taking the reforms forward.

The GMRG has commenced work on the transportation and capacity trading package of reforms. It has invited stakeholders from industry, consumer and end user groups, energy market bodies and governments to be involved on a high level advisory panel, and project teams which will undertake design and development work on these reforms. The GMRG has indicated that it will provide its final recommendations to the COAG Energy Council by December 2018.[30]

The indicative implementation schedule produced by the COAG Energy Council suggests that the transportation (pipeline and hub services) capacity trading package of reforms, including amendments to the NGL, NGR and subordinate instruments, will be completed by mid-2021.[31]

1.6 The rule making process

On 3 March 2016 the Commission published a notice under s. 303 of the National Gas Law (NGL) advising of its intention to commence the rule making process and the first round of consultation in respect of the rule change request. A consultation paper identifying specific issues for consultation was also published. Submissions closed on 31 March 2016.

The Commission received 15 submissions and two supplementary submissions. On 28 April 2016 the AEMC extended the date for publishing the draft rule determination on the gas day harmonisation rule change request from 26 May 2016 to 18 August 2016. This was to allow consideration of important issues raised in submissions on the consultation paper including the scope of the proposed rule and the complexities in implementing a harmonised gas day start time.

A second extension of time to make the draft rule determination was made on 18 August 2016. This extended the time from 18 August 2016 to 17 November 2016. It was made to allow consideration of the complexities in implementing a harmonised gas day start time and the significant inter-relationship with recommendations made in stage 2 of the east coast gas market review.

The Commission published its draft rule determination on this rule change request on 17 November 2016.[32] The Commission received nine submissions on the draft rule determination.[33]

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29 COAG Energy Council, Gas market reform package, Bulletin two, Appendix A – Response to ACCC and AEMC's recommendations, 19 August 2016.

30 The Chair of the GMRG, Dr Michael Vertigan, confirmed this by letter on 20 January 2017.

31 COAG Energy Council, Gas market reform package, Bulletin two, Appendix B – Governance arrangements and indicative implementation schedule, 19 August 2016.

32 A notice was published under s. 308 of the NGL.

33 All stakeholder submissions have been referenced in the relevant chapters of this final rule determination.

2 Final rule determination

In accordance with s. 311 of the NGL, the Commission has made this final rule determination in relation to the rule proposed by the COAG Energy Council.

The Commission has determined to make a final rule, which is a more preferable rule. The final rule harmonises the start time of the gas day used in the STTM and the GSH with the gas day start time used in the Victorian DWGM.

This chapter outlines:

- the Commission's rule making test for changes to the NGR
- the assessment framework used by the Commission for considering the rule change request
- a description of the final rule
- the consideration of the final rule against the NGO
- how the final rule contributes to the AEMC's strategic priority of promoting the development of efficient gas markets.

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

2.1 Rule making test

Under s. 291(1) of the NGL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NGO. This is the decision-making framework the Commission must apply.

The NGO is:[34]

> “ to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.”

The Commission considers that the most relevant aspect of the NGO for the purpose of this rule change request is the efficient operation and use of natural gas services.

2.2 Assessment framework

In assessing the rule change request against the NGO, the Commission has taken the following into account:

- **Reduce the administrative and operational costs of participants.** If the gas day start time and other gas day activities referable to a gas day start time, such as deadlines for submission of bids and offers and the publication of the ex ante market schedule and prices, are consistent across all facilitated markets, market participants (and possibly AEMO as market operator) may be able to streamline activities and reduce administrative and operational costs. Not having to manage

34 Section 23 of the NGL.

current gas day differences between locations may provide a cost saving to some participants.

- **Potential to enhance the efficient operation of facilitated gas markets and use of natural gas services.** Aligning the gas day may enhance the interconnectedness of the facilitated markets and participants' ability to readily trade between regions. Participants may also be able to more readily find opportunities for arbitrage thereby promoting the flow of gas to its highest value end use.

The Commission has assessed the identified benefits against the implementation and potential ongoing costs of the proposed rule, and the final rule, and compared this against the counterfactual of making no change to the current arrangements.

2.3 The final rule

The Commission can make a rule that is different (including materially different) from a proposed rule if it satisfied that, having regard to the issues raised in the rule change request, the more preferable rule will, or is likely to, better contribute to the achievement of the NGO.[35]

The Commission has made a final rule, which is a more preferable rule, that harmonises the start time of the gas day used in the STTM hubs and the GSH trading locations with the gas day start time used in the Victorian DWGM. The final rule is attached to and published with this final rule determination.

Consistent with the COAG Energy Council's rule change request, and the Commission's draft rule, the Commission has made a final rule to amend the definition of gas day in rule 364 of the NGR such that for the STTM a gas day is a period of 24 consecutive hours beginning at 6.00 am on each day. In addition to amending the STTM gas day start time, the Commission has determined that a new provision in the NGR (which was not included in the proposed rule) be introduced to provide certainty that gas allocation information provided to AEMO under the NGR is determined using measurements corresponding to the STTM gas day. This new provision also provides greater certainty that the final rule would trigger 'change of law' provisions in contracts to allow STTM pipeline operators to pass through certain costs associated with the change in the STTM gas day start time.

In summary, with respect to the STTM the final rule:

- amends the definition of gas day in rule 364 of the NGR such that for the STTM a gas day is a period of 24 consecutive hours beginning at 6.00 am AEST on each day
- requires allocation data provided by allocation agents for STTM facility operators to be derived using metering data based on the new gas day. It would apply to the measurement of both deliveries to, and withdrawals from, a STTM hub.[36]

The Commission's approach to amending the gas day start time in the GSH differs to that proposed in the COAG Energy Council's proposed rule. The COAG Energy

35 Section 296 of the NGL.

36 Rule 369A of the final rule.

Council's proposed amendment to Part 22 of the NGR (namely, rule 541(2) of the proposed rule) applies to "procedures and timing requirements for conducting trading, concluding transactions, payment and settlement" in the GSH. However, this is not consistent with the intent of the rule change request. The rule change request clearly states that the COAG Energy Council does not intend to change the trading hours (as distinct from the 'gas day') in the GSH.[37]

The Commission has therefore made a final rule which it considers is consistent with the COAG Energy Council's intent by focusing on the period for delivery, supply and acceptance of goods and services offered for trading in the GSH. The final rule gives effect to a change in the gas day start time for the GSH by requiring under the NGR that the exchange agreement must:[38]

- define a gas day as a period of 24 consecutive hours beginning at 6.00 am AEST (without adjustment for daylight savings in any jurisdiction)
- specify the period for delivery, supply or acceptance of goods or services offered for trading on the gas trading exchange by reference to one or more whole gas days or (where that period is shorter than one gas day) part of a gas day.

These changes would have the effect of requiring products offered through the GSH to be specified by reference to a gas day start time of 6.00 am AEST. The trading hours would remain unchanged.

2.4 Summary of reasons

Having regard to the issues raised in the rule change request and submissions the Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NGO. This is because it is likely to:

- Reduce the cost and complexities that market participants operating (or wishing to operate) across multiple facilitated markets currently face, including pipeline operators located at the interface of markets with different gas day start times.
  - In some circumstances, pipeline operators are currently managing the differences in gas day start times for participants operating in multiple markets by using the linepack available on pipelines and the imbalance allowances provided to shippers. Where employed, these strategies address the issue for shippers to account for the differences in gas days when moving gas between markets with different gas day start times. While these current contractual and operational arrangements appear to have worked well to date, there are costs to implementing these strategies.
  - The final rule should support the reduction of any existing complexities and provide benefits such as operational efficiencies to some participants. This is likely to lower the cost of providing natural gas services and should ultimately flow through to consumers in the form of lower prices.

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37 COAG Energy Council stated that "Gas trading occurs on the GSH between the hours of 9.00 am and 5.00 pm EST and the expectation is that this would remain unchanged", COAG Energy Council, rule change request, 19 November 2015, p. 7.

38 Rule 541(2) of the final rule.

- Support current trading developments, including multi-asset gas transport and short term capacity trading services by increasing the degree of interoperability and interconnection between the markets and, in doing so, promote participation and liquidity in these markets and trade between locations.
  - The east coast gas market is changing. The LNG industry in Queensland is contributing towards changing market dynamics and creating opportunities for the trade of gas. Pipeline operators are responding by offering shippers' capacity trading services and the ability to transport gas between markets across more than one pipeline under multi-asset gas transport agreements. Such transport and trading services should provide gas market participants with the opportunity to actively manage their own gas needs in a more flexible manner. The final rule is expected to support these current trading developments. With a common gas day of 6.00 am AEST, it is likely to be simpler to provide these capacity trading and multi-asset services, increasing the opportunities for trade and arbitrage between markets. As a result, by increasing liquidity and the opportunities for arbitrage, gas is likely to flow to its highest value end use.
- Support the future development of the new market arrangements announced by the COAG Energy Council. Specifically, the creation of an integrated east coast market that includes exchange-based trading in a wholesale market and also provides participants with the ability to make short-term pipeline capacity trades requires a number of features to be successful. One of these features is a common gas day across the east coast gas market:
  - Different gas day start times do not in themselves inhibit gas flows between locations. However, capacity markets interact with commodity markets. In order to trade and arbitrage between locations seamlessly it is preferable that the schedules of capacity markets and the facilitated markets align within, and between, locations.
  - To the extent that auction schedules for capacity, which are developed as part of the transportation reforms, are harmonised, a common gas day would also be desirable. By enabling seamless trading between regions, harmonising the gas day in facilitated gas markets and short term capacity markets is expected to promote participation, competition and liquidity in these markets.

The final rule aligns the STTM and the GSH gas day start times to 6.00 am AEST as used in the Victorian DWGM. The morning gas demand peak in Victoria makes 6.00 am AEST the most appropriate gas day start time from an operational and market perspective in Victoria. The Commission has concluded that the detrimental operational implications on the DTS and the market pricing effects on the Victorian DWGM would outweigh the benefits of introducing an 8.00 am AEST gas day start time as favoured by some Queensland market participants. A 6.00 am AEST gas day start time was therefore found to be the optimal option for achieving market harmonisation. This outcome is also likely to be the case under the new exchange-based wholesale trading market to be designed by the GMRG.

The Commission considers that the final rule will, or is likely to, better contribute to the achievement of the NGO than the proposed rule. In particular, requiring allocation information in the STTM to be made using metering data based on the new gas day is likely to:

- enhance confidence in the accuracy of allocation data
- support the triggering of change of law provisions under GTAs which will allow the pass through of costs resulting from changes to metering infrastructure and may enable parties to align the gas day in GTAs with the STTM gas day (depending on the terms of the GTAs).

The final rule, through the creation of a common gas day in the facilitated markets, is consistent with changes that are already occurring in the east coast market such as trading platforms and multi-asset services. However, if the rule was to commence in the near term, the benefits of doing so would be limited and would not outweigh the implementation costs.

For these reasons, changes to the gas day start time in the STTM hubs and GSH trading locations under the final rule are to commence on 1 April 2021. This commencement date was selected to coincide with the COAG Energy Council’s indicative timing for implementation of reforms relating to capacity standardisation and trading in pipeline capacity.[39] By implementing a harmonised gas day in conjunction with these reforms at a later date greater benefits are expected to emerge. As such, the Commission considers that this extended period for implementation shifts the cost-benefit assessment and net benefits can be expected to emerge.

2.5 Strategic priority

This rule change request relates to the AEMC's strategic priority of promoting the development of efficient gas markets, consistent with the COAG Energy Council's vision for Australia's future gas markets. This strategic priority recognises the structural changes underway and the significance of gas in the Australian economy. The AEMC's east coast gas review, from which this rule change arose, has been a key area of focus in pursuing this strategic priority.

The final rule to harmonise the gas day start times of the STTM and GSH with the Victorian DWGM gas day start times of 6.00 am AEST is expected to contribute to the efficiency of gas markets by reducing administrative and operational costs for participants and promoting participation, trading and liquidity in the gas market.

39 The COAG Energy Council's implementation schedule for market reforms is discussed in more detail in Chapter 6.

3 The benefits of a harmonised gas day

This chapter sets out the COAG Energy Council's views, stakeholder views and the Commission's analysis with respect to the benefits of harmonising the gas day start time across east coast gas markets.

3.1 Benefits across the facilitated markets

3.1.1 COAG Energy Council's view

The COAG Energy Council identified some potential broad benefits to harmonising the facilitated markets' gas day start times. These are:

- reducing complexities and enabling market participants to streamline their activities across the facilitated markets and possibly find opportunities for cost savings[40]
- increasing opportunities for trade and arbitrage between regions, enabling gas to flow to its highest value use[41]
- providing market participants with greater certainty and confidence that the gas day start time would become and remain aligned by introducing the gas day start time for the GSH in the NGR
- supporting the development of financial risk management tools.[42]

3.1.2 Stakeholder views - first round consultation

The concept of harmonisation

The majority of stakeholders expressed broad in principle support for gas day harmonisation, particularly if carried out as part of the broader package of east coast as market reforms identified in the AEMC's east coast gas review.[43] This is highlighted in the following statement by Engie:[44]

> "GDFSAE's rational [sic] for supporting harmonisation is that it is one of a number of pre-conditions to supporting the growing interconnectedness between gas markets, and in turn gas and electricity markets, in Australia. Therefore, to improve optimisation of gas trading and transportation between locations and readily identify arbitrage opportunities, gas day harmonisation is required. GDFSAE's own experience suffers from the complexities of unaligned gas days. Notably, trades over jurisdictional and

40 COAG Energy Council rule change request, 19 November 2015, p. 6; p. 9.

41 ibid, p. 6.

42 ibid.

43 Submissions on the consultation paper: APA, p. 1; APGA, p. 1; APLNG, p. 1; APPEA, p. 1, EnergyAustralia, p. 1; Engie, p. 1; MEU, p. 1; QGC, p. 1; Stanwell, p. 1. AGL also noted that while it did not consider harmonisation to be strictly necessary, it considered it a "sensible change and that if supported by the wider industry should go ahead". AGL, submission on the consultation paper, p.1.

44 Engie, submission on the consultation paper, p. 1. Note that Engie made a submission under its previous name of GDF Suez. GDF Suez announced its change of name in April 2016.

market boundaries are complicated by mismatched gas days between markets, and mismatched gas days between pipelines and producers. This is suboptimal and undermines gas transportation and trade."

However, questions were raised by some stakeholders about the magnitude of the benefits of harmonisation and whether these benefits would exceed the costs. For example:

- The Australian Pipelines and Gas Association (APGA) suggested that the benefits of harmonisation may be low given that, among other things, there "has been an absence of calls for the market start times to align" during the development of the facilitated markets or post-implementation.[45] APGA added that it is not enough to find that one start time is simpler than three, it must be demonstrated that the benefits will outweigh the costs.[46]
- Jemena stated that it was not aware of any benefits to its customers from harmonising the facilitated markets gas day start times and added that the benefits of the proposed rule should be quantified and clearly demonstrated to outweigh its costs.[47]

A number of stakeholders also expressed differing views on whether the benefits cited by the COAG Energy Council would be realised. Other stakeholders noted the potential for the benefits to be undermined if the change to the gas day was not also extended to gas supply, storage and transportation contracts. Stakeholders' views on these issues are set out in more detail in section 3.2.

In addition, it is worth noting that in its inquiry into the east coast gas market, the Australian Competition & Consumer Commission (ACCC) also recommended that steps be taken to align the gas day start time across facilitated markets, as well as the nomination times employed by producers and pipeline operators. In doing so, the ACCC noted that these measures, along with a number of other measures identified in the AEMC's east coast gas review, would "reduce any potential barriers to trade and transaction costs".[48]

Operational benefits

Stakeholders expressed a range of views about whether harmonising the facilitated markets' gas day start times, particularly the STTM hubs, would reduce complexity and costs for participants operating across locations.

Engie claimed that the lack of alignment across STTM hubs has added complexity to the market and increased compliance costs for participants operating across STTM hubs with different gas day start times.[49] AGL expressed a similar view, stating that differences in the gas day start times across facilitated markets represents a "further complication to an already complex market". However, in its view, new entrants were

45 APGA, submission on the consultation paper, p. 1.

46 ibid, p. 2.

47 Jemena, submission on the consultation paper, p. 2.

48 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 79.

49 Engie, submission on the consultation paper, p. 1.

more likely to be affected by the differences than existing market participants who have already developed systems and contractual arrangements to manage the trading requirements at each location.[50]

Engie also considered that contingency and emergency arrangements could be better managed if there was a harmonised gas day. It submitted that in the past, unaligned gas days may have contributed to confusion between parties when planning contingency arrangements.[51]

In contrast to Engie and AGL, Origin claimed that there were benefits to having different gas day start times because it allowed businesses to stagger their trading activities and also accorded them some degree of operational flexibility.[52] AGL also referred to the benefits of being able to stagger trading activities across the day, but noted that this could still be accommodated by retaining the currently staggered market settlement times in the STTM, that is, 12.00 pm AEST in Sydney and Adelaide and 1.30 pm AEST in Brisbane.[53] Jemena commented that it was not clear how material the current market complexities are to market participants and so not clear what benefit would arise for its customers in making a change to these current arrangements.[54]

AEMO stated that the different gas day start times for the STTM hubs did not contribute to the complexity of market operations or systems. It noted that the STTM market systems "are automated to run market actions at an offset to the gas day start time".[55] APA also noted that in providing information to the Sydney and Brisbane STTM hubs, it "is not materially affected by the different gas day start times that currently apply".[56]

Promoting trade between locations

A number of stakeholders, including APPEA, EnergyAustralia and Engie, considered that harmonising gas day start times across the facilitated markets would enhance the interconnectedness of the east coast market and promote liquidity and trading between locations.[57]

While QGC agreed to some extent with these potential benefits, it stated that it had not seen any evidence to suggest that misaligned gas days is a real barrier to trade across jurisdictions.[58] Similarly, Origin claimed that "gas has, and will, continue to flow to its highest value irrespective of gas day start times and it is not evident that harmonisation

50 AGL, submission on the consultation paper, p. 1.

51 Engie, submission on the consultation paper, p. 2.

52 Origin, submission on the consultation paper, p. 1.

53 AGL, submission on the consultation paper, p. 1.

54 Jemena, submission on the consultation paper, p. 2.

55 AEMO, submission on the consultation paper, p. 2.

56 APA, submission on the consultation paper, p. 3.

57 Submissions on the consultation paper: APPEA, p. 1; EnergyAustralia, p. 1; Engie, p. 1.

58 QGC, submission on the consultation paper, p. 3.

will result in greater levels of trading".[59] AGL noted that it "does not consider that different gas day trading times are a barrier to trading".[60]

Questions were also raised by QGC and APLNG in this context about the value in harmonising gas day start times before the transportation related reforms identified in the AEMC's east coast review were implemented.[61] Elaborating on this further, APLNG noted that it currently has limited access to transportation outside of Queensland and that until the other market reforms proposed by the AEMC were implemented, it would derive little benefit from harmonising its gas day start time with the DWGM.[62] Similarly, Stanwell also noted that it is not currently disadvantaged by inconsistent gas days as it is only trading in Queensland.[63]

Financial risk management

Stakeholders responding to this issue did not perceive gas day harmonisation to have a strong relationship with the development of financial risk management tools. AEMO, for example, stated that it did not consider that gas day harmonisation would be likely to directly support the development of risk management tools.[64] Origin also stated that it was unclear how harmonisation of gas day start times would support the use or development of financial risk management products.[65]

However, while APA noted that trading participants are best placed to comment on whether inconsistent gas day start times impede the development of financial risk management tools, it noted that standardisation should assist.[66]

3.1.3 Draft rule determination

The draft rule determination set out two key benefits the Commission expected harmonising the gas day start time in the facilitated markets would support. First, that harmonising the gas day start time would reduce the costs and complexities that market participants operating (or wishing to operate) across multiple facilitated markets currently face.

Second, harmonsing the gas day start time was expected to increase the interoperability and interconnection between markets which would promote participation and liquidity in these markets and trade between locations. The Commission concluded, however, that while a common gas day would support the future development of the new market arrangements identified by the AEMC in its east coast gas review, there was only limited potential for a harmonised gas day to provide certain benefits to some market participants under the current market conditions.

59 Origin, submission on the consultation paper, p. 1.

60 AGL, submission on the consultation paper, p. 1.

61 APLNG, supplementary submission on the consultation paper, pp. 1-2; QGC, submission on the consultation paper, p. 1; p. 3; QGC supplementary submission on the consultation paper, pp. 1-3.

62 APLNG, supplementary submission on the consultation paper, pp. 1-2.

63 Stanwell, submission on the consultation paper, p. 1.

64 AEMO, submission on the consultation paper, p. 2.

65 Origin, submission on the consultation paper, p. 1.

66 APA, submission on the consultation paper, p. 4.

3.1.4 Stakeholder views - second round consultation

Stakeholders were mixed in their views on whether there were material benefits to be achieved from harmonising the gas day of the facilitated markets. There were also mixed views on whether there was sufficient certainty regarding future reforms and whether these would require a common gas day to be successful.

AGL and Engie expressed support for harmonising the gas day start time of the facilitated markets. AGL noted that ensuring alignment in the GSH exchange agreement is a positive measure. Engie agreed that "the full benefits of the east coast gas review will be reliant upon [the] gas trading day being harmonised".[67]

APA and APPEA also supported harmonising the gas day start time of the facilitated markets. However, they remained concerned that the draft rule would be insufficient to achieve the intended outcomes because commercial activities outside the facilitated markets may not be impacted by a change in the gas day start time of the STTM and GSH.[68]

Shell also supported harmonising the gas day across the east coast gas markets in principle, stating:[69]

> “Shell supports the concept of harmonising the gas days across the east coast. It signifies an overarching commitment to establish a truly integrated east coast market and in theory standardised arrangements, generally, should reduce barriers to trade enabling gas to flow to customers who value it most.”

However, Shell, Stanwell and Jemena did not consider that a case had been made to harmonise the gas day start time in the facilitated markets.[70] These stakeholders did not consider that the materiality of complexities faced by market participants arising from difference in the gas day start time nor the magnitude of expected benefits had been clearly identified and quantified.[71]

Based on its recent experiences, Shell argued that the current arrangements are not materially inhibiting trade. It suggested further work was required to understand and substantiate how essential harmonising the gas day would be to the successful implementation of other gas market reforms.[72]

Shell stated its preference that the gas day start times in the Adelaide STTM, Sydney STTM and Moomba GSH be harmonised to the Victorian DWGM gas day start time of 6.00 am AEST with the Brisbane STTM and Wallumbilla GSH remaining on an 8.00 am AEST gas day start time. It argued that a reasonable proportion of gas would be traded under a common gas day under these arrangements and the cost and risks

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67 Submissions on the draft rule determination: AGL, p.1; Engie, p.2.

68 APA, submission on the draft rule determination, p.1.

69 Shell, submission on the draft rule determination, p.2. Note that QGC, which made submissions on the rule change request, is now a part of Royal Dutch Shell.

70 Submissions on the draft rule determination: Shell, p.1; Stanwell, p.1; Jemena, p.1.

71 ibid.

72 Shell, submission on the draft rule determination, p.1.

associated with shipping gas between southern and nothern markets would be reduced. These arrangements, it was suggested, could be reviewed following the implementation of other gas market reforms.[73]

Stanwell suggested it would be more appropriate not to proceed with the draft rule at this time given its benefits are contingent on future regulatory changes of uncertain form and timing.[74] Stanwell considered that the draft rule, if made, would create uncertainty for participants because it is possible that the complementary gas market reforms may be delayed or abandoned. This could put the expected benefits at risk or potentially require a rule change to delay the commencement of the harmonisation of the gas day.[75]

In addition, Jemena commented that it was not clear that consumers support the change given that the majority of consumer groups do not appear to have engaged in the rule change process to date.[76]

3.1.5 Commission's analysis

The Commission is aware that there are contractual and operational arrangements that market participants currently use to manage the differences in gas day start times across the east coast market.[77] While these arrangements appear to have worked relatively well to date, there are costs associated with negotiating these arrangements and implementing these strategies. In addition, such arrangements may not be available in all circumstances. Consequently, the arrangements currently used by market participants to manage different gas days should not be viewed as a costless alternative to harmonising the facilitated markets' gas day start times even if, for some participants, the practices are well established.

Participation in multiple facilitated markets has traditionally been the domain of a small number of large shippers. However, the east coast gas market is changing: there are new, small shippers emerging. In addition, there is an increasing number of participants looking to operate across multiple locations and to trade gas and transportation capacity in a more dynamic and short-term manner than in the past. These changes have been prompted by a range of factors including tighter conditions in the wholesale gas market, the development of the Queensland LNG facilities, changing conditions in

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73 Shell, submission on the draft rule determination, p. 2.

74 Stanwell, submission on the draft rule determination, p. 2.

75 ibid.

76 Jemena, submission on the draft rule determination, p. 1.

77 One example of current operational arrangements is in reference to the South West Queensland Pipeline (SWQP). The western end of the APA pipeline is at Moomba which operates with a 6.30 am AEST gas day start time. The eastern end of the SWQP is at Wallumbilla where the GSH operates on a gas day that starts at 8.00 am AEST. Nevertheless, shippers using this pipeline are not required to enter into a two-day transportation contract, nor required to negotiate a pro-rating arrangement so that the gas flow matches either the Moomba or Wallumbilla gas day. Instead, SWQP shippers nominate their requirements for a 'gas day' and the linepack available on the pipeline allows APA to operate it in a way that accommodates the difference in the gas days of the markets to which the pipeline is connected without any specific contractual requirements or any other action by the shippers.

the national electricity market and a change in the nature of demand by some market participants.

Pipeline services are already adapting to shippers' needs to be able to rapidly respond to price signals and move gas between locations. For example, APA now offers multi-asset services which provide shippers the ability to transport gas between markets across more than one pipeline. These multi-asset service gas transport agreements can be negotiated as part of new or existing long-term GTAs.[78] The Commission understands that in providing these multi-asset services, APA manages the differences in gas day start times on its pipelines through linepack and imbalance allowances provided to shippers.

In addition, the standard terms and conditions for APA GTAs and its capacity trading platform also appear to accommodate differences in the gas day used at various locations. These standard terms and conditions are relevant for both long and short-term contracts.

Changing market conditions are not expected to abate in the future. Participants' interest in new or more flexible gas services is also likely to continue. The Commission expects that harmonising the gas day start time across the facilitated markets would support current trading developments, including multi-asset gas transport and short-term capacity trading services. Nevertheless, the Commission remains of the view that if harmonisation was implemented in the near term under the current market arrangements, these benefits would be limited and may not outweigh the implementation costs.

However, the Commission considers that the introduction of a common gas day in the facilitated markets is likely to support the future development of the new market arrangements identified in the AEMC's east coast gas review which were accepted by the COAG Energy Council and are currently under development by the GMRG.

The market reforms recommended by the AEMC are intended to pave the way for the development of a more harmonised, integrated and dynamic market on the east coast. The anticipated changes include:[79]

- The development of two wholesale gas trading hubs on the east coast (the northern hub at Wallumbilla and the southern hub in Victoria), which will share common trading arrangements aimed at improved price discovery and reduced barriers to participation. These trading hubs will enable any market participant to buy or sell gas through a continuous exchange based trading mechanism on a short, medium or longer-term basis.
- A range of transportation reforms that facilitate a greater level of trading in pipeline capacity and hub services by:
  - introducing a day-ahead auction of contracted but un-nominated capacity

78 M Newton, 'Multi-asset gas transportation services providing new flexibility for shippers', *Gas Today*, Spring 2016.

79 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, stage 2 final report, 23 May 2016, pp. v-vii.

— developing a capacity trading platform to enable shippers to trade capacity ahead of the auction

— standardising certain conditions in primary and secondary transportation and hub service agreements, including gas day start times, to make capacity more tradeable.

Together, these reforms are expected to reduce transaction costs and make it easier for market participants to trade and transport gas across the east coast. In doing so, this is expected to provide for a more efficient allocation of gas across the market, benefitting gas consumers and industrial gas users.

The planned implementation of these market reforms include many components. As noted by a number of stakeholders, harmonising the gas day start time across the facilitated markets is one component of the overall reform package. However, the Commission acknowledges that not all stakeholders are concerned about the current use of different gas days in the facilitated markets or regard a common gas day as essential to future reforms.

While different gas day start times do not of themselves inhibit gas flows between locations, they lead to different schedules during the day. As stakeholders have observed, capacity markets interact with commodity markets. In order to trade and arbitrage between locations a shipper requires both capacity and gas. Accordingly, it is preferable that the schedules of capacity markets and the facilitated markets align within, and between, locations.

The final rule harmonises the gas days of the facilitated gas markets on the east coast. To the extent that auction schedules for capacity, which are developed as part of the transportation reforms, are harmonised, a common gas day would also be desirable. By enabling seamless trading between regions, harmonising the gas day in facilitated gas markets and short term capacity markets should promote participation, competition and liquidity in these markets.

Harmonising the gas day in the facilitated markets, and capacity markets, will also provide for a reduction of costs and complexities that market participants operating (or wishing to operate) across multiple facilitated markets currently face. This includes pipeline operators located at the interface of markets with different gas day start times.

These expected benefits may in turn lower the cost of providing natural gas services and should ultimately flow through to consumers and large users in the form of lower prices. The Commission also anticipates that parties outside these faciliatated markets will be incentivised to align their activities with the gas day in these markets. As a result, the expected benefits of the final rule may be enjoyed more widely across the east coast.

The Commission has also considered that Shell's suggestion to only align the gas day start time in the facilitated markets located in New South Wales and South Australia to the Victorian DWGM gas day start time of 6.00 am AEST while retaining the 8.00 am AEST gas day start time in the facilitated markets located in Queensland. It considers that this approach would not achieve the expected benefits outlined above.

The recommendations made by the AEMC relating to the development of two wholesale gas trading hubs on the east coast, and transportation and capacity trading reforms were endorsed by the COAG Energy Council at its August 2016 meeting, subject to further stakeholder consultation by the AEMC on the details of the recommendations relating to the southern hub.[80] At this meeting the COAG Energy Council announced the establishment of the GMRG to take the reforms forward.

The GMRG has commenced work on the transportation and capacity trading package of reforms outlined above in early 2017. This package of work will also consider whether:

- any amendments need to be made to the NGL to give the AEMC, AEMO or the AER additional powers in respect of the regulation of capacity trading arrangements
- any other amendments need to be made to the NGL, NGR or subordinate instruments to give effect to the reforms.

The GMRG has invited stakeholders from industry, consumer and end user groups, energy market bodies and governments to be involved on a high level advisory panel, and project teams which will undertake design and development work on these reforms. The GMRG has indicated that it will provide its final recommendations to the COAG Energy Council by December 2018.[81]

The indicative implementation schedule produced by the COAG Energy Council suggests that the transportation (pipeline and hub services) capacity trading package of reforms, including amendments to the NGL, NGR and subordinate instruments, will be completed by mid-2021.[82]

The Commission is satisfied that the COAG Energy Council endorsement of the transportation and capacity trading reforms, and GMRG's commencement of work provides a sound basis for making the final rule to harmonise the gas day start times in the facilitated markets in April 2021.

3.2 Potential risks to achieving the benefits of harmonisation

3.2.1 COAG Energy Council views

The COAG Energy Council did not identify any potential risks it expected to arise from harmonising the gas day start time in the facilitated markets. However, it did acknowledge that if the proposed rule was made, AEMO may then be required to carry out change processes for the STTM and retail market procedures as well as being required to amend the exchange agreement.[83] It also anticipated that industry participants would need to implement changes to contracts, infrastructure and business practices.[84]

80 COAG Energy Council, Gas market reform package, Bulletin two, Appendix A – Response to ACCC and AEMC’s recommendations, 19 August 2016.

81 The Chair of the GMRG, Dr Michael Vertigan, confirmed this by letter on 20 January 2017.

82 COAG Energy Council, Gas market reform package, Bulletin two, Appendix B – Governance arrangements and indicative implementation schedule, 19 August 2016.

83 COAG Energy Council, rule change request, 19 November 2015, p. 7.

84 ibid, p. 10.

3.2.2 Stakeholder views - first round consultation

A number of stakeholders claimed the expected benefits of gas day harmonisation may not be realised (or could be undermined) because the proposed rule only relates to the facilitated markets and does not require harmonisation of the gas days, or equivalent periods of time, used by producers, storage providers and pipeline operators not active in STTM hubs or GSH trading locations.

For example, AEMO expressed concern about the risk to participants and the efficient operation of the markets if the rule change was only limited to the facilitated markets and did not extend to the gas day start times, or equivalent periods of time, set out in gas supply, storage, and transmission and distribution pipeline contracts.[85] It also noted the potential for a misalignment in gas day start times in such arrangements to introduce a set of new and additional risks and deter participants from trading in the GSH.[86] To address this concern, AEMO suggested that a "legislated change" to the gas day start time, which would apply to all parties across the east coast gas market, would aid the necessary amendment of contracts.[87]

Pipeline operators were also concerned that only changing the gas day start time in the facilitated markets may result in multiple gas day start times within single jurisdictions or on a single asset, resulting in greater operational inefficiencies. APA commented that:[88]

> "At present APA deals with differences in gas day start times at two key interface points, Moomba (SA/NSW/QLD) and Culcairn (Vic/NSW). APA has developed processes and procedures to deal with these interface issues that are currently operating effectively. Should the changes to facilitated markets proceed without overarching legislative changes to all contracts (GTAs and GSAs) then the potential exists for multiple different gas day interfaces to develop."

Jemena expressed similar concerns, providing the following example to illustrate why it considers inconsistent gas day start times may develop:[89]

> "a small production facility that is not directly connected to a participant in a facilitated market – but is connected to a pipeline serving that market – may be reluctant to change its own contracts and systems to align with a new gas day start time. If this producer decides not to change times in its GSAs, a shipper that uses both facilities may choose not to agree to change its GTA, leaving the pipeline operator with inconsistent gas days for shippers and pipelines."

Jemena suggested that a more preferable rule could be made which specified that all facilities that use, or are connected to, a pipeline that services the STTM, GSH or DWGM must use a standardised gas day start time. Jemena considered such a preferable rule

85 AEMO, submission on the consultation paper, p. 1.

86 ibid, pp. 1-2.

87 ibid, p. 5.

88 APA, submission on the consultation paper, p. 3.

89 Jemena, submission on the consultation paper, p. 3.

would "remove any potential doubt as to the satisfaction of law/rule change event provisions under contracts".[90]

APGA also noted that some parties may have limited incentive to adopt a new gas day. It stated:[91]

> “shippers that have no interest in participating in facilitated markets may have little incentive to incur any costs arising from a change from existing gas day start times.”

A number of shippers including EnergyAustralia, APLNG and QGC also raised concerns that misalignments in the gas day between the markets, pipelines and contractual arrangements would emerge from implementation of the proposed rule and this would create operational and commercial risks as well as costs. In APLNG’s assessment, the risk of misalignments arising within its existing business outweigh the benefits of being able to coordinate gas movements along the east coast.[92]

EnergyAustralia also identified potential operational risks. For example, it suggested that a misalignment between the starting times for markets and for pipelines could result from the proposed rule and lead to a situation where shippers are charged or have to acquire park and loan facilities on pipelines which could be a significant cost.[93] QGC submitted that without "broader gas day alignment" market participants could potentially be operating across two different gas days where they are currently operating under one gas day. It considered this outcome would be unworkable due to the significant and complex scheduling and balancing issues this would create.[94]

The Major Energy Users (MEU) also commented that the rule change should be "all encompassing across all gas contracts".[95] The MEU considered that if gas capacity trading on pipelines is introduced, it would be essential for the gas day start times in contracts to be harmonised with the market gas day start time.[96]

3.2.3 Draft rule determination

In the draft rule determination, the Commission acknowledged that the draft rule applied specifically to the STTM and GSH facilitated markets. However, it also considered that some market participants would be incentivised to adopt a 6.00 am AEST gas day start time if the draft rule was made. This may occur over time, as participants in the east coast gas market find that the costs of making a change are outweighed by the benefits under their particular circumstances.

90 ibid.

91 APGA, submission on the consultation paper, p. 2.

92 APLNG, supplementary submission on the consultation paper, p. 2.

93 EnergyAustralia, submission on the consultation paper, p. 1

94 QGC, submission on the consultation paper, p. 2. QGC is now part of Royal Dutch Shell which subsequently made submissions on the draft rule determination.

95 MEU, submission on the consultation paper, p. 1.

96 ibid.

The Commission also commented that it expected that the incentives for these market participants are likely to increase over time and this counters the risk that the potential benefits from the final rule will be undermined.

3.2.4 Stakeholder views - second round consultation

APA and AEMO expressed concern that the draft rule risked leading to more than one gas day applying across a single jurisdiction, and potentially to a single pipeline. In their view, this would significantly increase the costs and complexity of the market rather than reduce it.[97] AEMO considered the draft rule "could make nomination and allocation processes more complex, creating additional risks for participants in managing their physical positions thus deterring trade within the facilitated markets".[98] If a pipeline was forced to manage multiple gas day start times on a single pipeline, this would also significantly increase the cost and complexity of pipeline operations.[99]

APA suggested that:[100]

> “had the rule change proposed a requirement for all data submitted to the National Gas Services Bulletin Board, it would have affected a far greater number of contractual arrangements and significantly improved the chance of a successful and lower cost implementation”

However, AEMO considered that the GMRG would be the appropriate body to consider a law change (or a broader rule change) as part of its broader reform package.[101]

APPEA's perspective differed from APA and AEMO. It submitted that feedback on the proposed rule indicated a number of unintended consequences. While the draft rule is limited to requiring activities in the STTM and GSH being conducted according to the new gas day start time, APPEA considered the draft rule would impact on commercial activities outside of these facilitated markets.[102] APPEA referred to submissions on the consultation paper by QGC and APLNG. It noted that these submissions indicated that changes to GTAs, GSAs and metering infrastructure and systems are likely to cost upwards of $20 million.[103]

AGNL was concerned that the draft rule would not apply to all non-STTM regional sub-networks such as those at Wagga, Wide Bay, Port Pirie and Mildura.[104] AGNL explained its data collection and retail market reporting systems are programmed for a single gas day start time in each jurisdiction. To manage two different gas day start times would require two separate systems to be run in parallel with additional costs of duplication. AGNL therefore recommended that the Retail Market Procedures be

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97 Submissions on the draft rule determination: APA, p. 1; AEMO, p. 2.

98 AEMO, submission on the draft rule determination, p. 2.

99 APA, submission on the draft rule determination, p. 1.

100 ibid.

101 AEMO, submission on the draft rule determination, p. 2.

102 APPEA, submission on the draft rule determination, p. 1.

103 ibid.

104 AGNL, submission on the draft determination, p. 1.

changed by AEMO to introduce a common gas day start time for all sub-networks in all jurisdictions.[105]

3.2.5 Commission analysis

Like the proposed rule, the draft rule, required a consistent gas day of 6.00 am AEST be used in the STTM and GSH. It did not require parties external to these markets to adopt a consistent gas day. As stakeholders have commented, market participants are likely to face some impediments to trading gas and pipeline capacity if the gas day start times employed by producers, storage providers and all pipeline operators are not aligned with the common market time.

Figure 3.1 identifies those areas on the east coast where a misalignment may occur, either because a facility is not already operating on a 6.00 am AEST start time, or because it is not an STTM connected facility and would not be required to change its operations under the proposed rule, and the draft rule. As this figure highlights, the potential for misalignment of gas days on major facilities in the east coast will primarily occur in Queensland and potentially Moomba.[106]

105 ibid.

106 Upon the commissioning of the Northern Gas Pipeline, the Northern Territory gas market will be physically connected to the east coast gas market at Mt Isa. The Commission understands that facilities in the NT operate on a gas day commencing at 8.00 am Australian Central Time. Without a change to contracts and facility operations, Mt Isa will also be a location where a misalignment of gas day will occur.

Figure 3.1 Potential gas day misalignments in the east coast gas market

Source: AEMC.

In responding to the rule change request, a number of stakeholders expressed concern that the expected benefits of gas day harmonisation may not be realised or could be undermined because the proposed rule only related to the facilitated markets and misalignments, as illustrated in Figure 3.1. could occur. Some stakeholders suggested the misalignments and consequent unrealised benefits of the proposed rule should be addressed by requiring all market participants across the east coast to change the definitions of the gas day, or equivalent periods of time, in their gas supply, transportation and storage contracts. The alternative mechanisms suggested to achieve a common gas day included making a more preferable rule that applied more broadly than the facilitated markets or making a legislative change that would apply across the east coast gas market.

Alternatives proposed by stakeholders

The Commission acknowledges the benefits that stakeholders have identified in using a clear and broadly applied rule or law to make a change such as amending the gas day start time. It has considered the suggested alternatives.

First, it has considered the suggestion to make a broad-reaching more preferable rule that would extend the application of a uniform gas day beyond just the east coast facilitated markets: the Commission does not consider this alternative approach to the proposed rule is possible. This is because the Commission is unable to broaden the scope of a rule change and the scope of this rule change request is clearly limited to harmonising the gas days used in the STTM and the GSH with the gas day in use in the DWGM. The rule change request did not make a broader proposal to introduce a uniform gas day that applied to activities beyond the facilitated gas markets. In addition, making a rule that would have such a broad application is unlikely to fall within the Commission's current rule making powers.[107]

Secondly, the suggestion from some stakeholders to make a legislative change that would apply to parties across the east coast gas market is beyond the scope of the Commission's powers as it is unable to make changes to the NGL. However, if stakeholders consider law changes have merit, this suggestion would be best discussed with the GMRG which may make recommendations to the COAG Energy Council on legislative amendments required to implement the gas market reform package.

Thirdly, the Commission has considered APA's suggestion that wider harmonisation could be encouraged by requiring that all data submitted to the National Gas Services Bulletin Board be submitted in accordance with a 6.00 am AEST gas day start time. In this regard, the Commission is concerned that amending the Bulletin Board rules to compel parties outside of the facilitated markets to use a specific gas day start time may be beyond the stated purpose of the Bulletin Board which is to make information readily available to the market.[108] In addition, the making of such a rule would have broader implications than the intent of the rule change request which focused on

107 More specifically, a rule with such a broad application is unlikely to fall within the scope of the matters referred to in s. 74 and Schedule 1 of the NGL in respect of which the Commission may make rules as it would constitute a rule defining pipeline services rather than being a rule in respect of the “provision” of such services.

108 Rule 142 of the NGR.

aligning the gas day start time in the STTM and GSH with the DWGM. As a result, such a rule would be beyond the scope of the Commission's more preferable rule making power.

Scope of changes under the final rule

The Commission has made a final rule which, like the proposed and draft rules, is limited to only requiring changes be made in respect of the STTM and the GSH markets. The effect of the final rule will be as set out in Figure 3.1. Nevertheless, while the operation of final rule is limited to changing the gas day in those facilitated markets, the Commission considers market participants operating outside those markets are likely to voluntarily adopt a 6.00 am AEST gas day start time when it is efficient for them to do so.

For example, shippers that want to purchase gas from the Wallumbilla GSH and transport that gas to Sydney, Adelaide or Victoria are likely to have an incentive to harmonise their gas supply, transportation and storage contracts if it will make it easier to co-ordinate trades and reduces transaction and operational costs. Where some shippers seek to establish a common gas day across their business activities, this may in turn provide an incentive for their counter-parties to also use a gas day consistent with the facilitated markets. Even those established shippers that have systems and contractual arrangements in place to deal with the existing differences in the gas day may have an incentive to make such changes when their existing contracts end. In making these changes, these participants would eliminate the ongoing cost of maintaining their current commercial and operational mechanisms for managing the misalignment in gas days.

Similarly, producers that want to participate in the GSH or supply gas into new areas south eastern Australia, may also have an incentive to change the gas day start time for their operations if the benefit of doing so exceeds the cost of making the necessary changes to meters, business systems and contracts. Some producers have submitted they have a large number of meters that would require a technician to manually change the gas day for each meter. For these producers, the change-over cost may be significant and not warrant the immediate adoption of a new gas day. However, as meters are repaired, updated or replaced over time it may become a more feasible option to adopt a new gas day. For other producers that have fewer meters or can access their meters remotely, the adoption of a new gas day may be feasible sooner.

Pipelines that are not using a 6.00 am AEST gas day start time and are not STTM pipelines will not be required to use the new gas day under the final rule. However, the operators of these pipelines may also have an incentive to adopt a 6.00 am AEST gas day start time if there are operational efficiencies in doing so and/or connected pipelines are already operating with a 6.00 am AEST gas day start time.

Also, in relation to regional sub-networks, such as Wagga, Wide Bay, Port Pirie and Mildura, while it is outside the scope of the rule change to require AEMO to make changes to the gas day start time in these sub-networks. However, the final rule does not preclude AEMO from considering the issue when it consults and makes changes to the Retail Market Procedures to be consistent with the new gas day start time in the STTM and GSH of 6.00 am AEST under the NGR. Stakeholders can raise their concerns during AEMO's consultation process regarding any inefficiencies that may occur if the regional sub-networks are not also harmonised to a 6.00 am AEST gas day start time.

Conclusion

On balance, the Commission considers that some market participants will be incentivised to adopt a 6.00 am AEST gas day start time if a rule that applies this start time to the facilitated markets is made. However, not all participants will find that the benefits will outweigh the costs in the short term. In these cases, contractual and operational arrangements such as those already in place in some locations can be used to manage the differences. While these arrangements are not substitutes for harmonising the gas day start time, they should allay the concerns held by some stakeholders about the potential for gas day misalignment to undermine the benefits of harmonising the facilitated markets' gas days.

The Commission considers that the incentives for the market participants noted above are likely to increase over time and this counters the risk that the potential benefits from the final rule will be undermined. In particular, following the introduction of the planned market reforms to establish continuous exchange-based trading of gas and a pipeline capacity trading market (including the use of standard transport contract terms), participants are likely to have a greater incentive to adopt a 6.00 am AEST gas day start time as it will enable them to participate in the new markets more easily.[109]

109 See Chapter 6 for further discussion on implementation of the final rule.

4 Cost of implementing a harmonised gas day

This chapter sets out:

- the COAG Energy Council's views on the costs of implementing the proposed rule
- detailed stakeholder feedback on the type and extent of costs expected to be incurred in implementing a gas day start time of 6.00 am AEST across the east coast
- the Commission's analysis of the costs of implementing the rule change.

4.1 The COAG Energy Council's view

The COAG Energy Council's rule change request recognised that there would be a number of one-off costs associated with harmonising the gas day start times in the facilitated markets including:

- re-setting and modifying coding for each field flow computer
- amending contracts including gas transportation agreements and gas supply agreements
- modifying business procedures
- amending the GSH exchange agreement.[110]

The COAG Energy Council anticipated that the rule change process would allow the AEMC to investigate in more detail the operational, commercial and procedural work required to harmonise the gas day start times in the facilitated markets.[111]

4.2 Stakeholder views

4.2.1 First round consultation

AEMO

AEMO has estimated that it will cost approximately $100,000 to make changes to its IT systems, infrastructure and procedures and processes if the gas day start time is amended to 6.00 am AEST in the STTM and the GSH.[112]

IT systems

AEMO indicated that the proposed new gas day start time can be implemented in the STTM through changes to the configuration of the scheduling application. The STTM market systems are automated to run market actions at an offset to the gas day start time. Accordingly, re-configuration of the start time will have the flow on effect of changing the intra-day times of activities while retaining the relative time frames.

110 COAG Energy Council, rule change request, 19 November 2015, p. 10.

111 ibid.

112 AEMO, submission on the consultation paper, p. 4.

According to AEMO, a new gas day start time can also be implemented in the GSH through configuration only with no functional changes being required. The only area where the GSH will be affected is the balance-of-day product calculation which currently uses the start time 8.00 am AEST for Wallumbilla and 6.30 am AEST for Moomba. The only change that is required, therefore, is a relatively simple data change which updates the gas day start time to 6.00 am AEST.

For changes to both the GSH and the STTM, AEMO has indicated it would require system testing and a planned release with the relevant market participants.[113]

Procedures and processes

There are also a number of other activities that AEMO expects it will undertake in response to a rule being made. These include:[114]

- undertaking industry consultation and making modifications to the Retail Gas Market Procedures (for Queensland, New South Wales and the Australian Capital Territory) and the STTM Report Specifications to amend the gas day start time and the timing of daily market activities
- amending the GSH exchange agreement to reflect the new gas day start time which would similarly require a consultation process with exchange agreement members (as provided for under the exchange agreement).

Upstream

Gas producers have indicated that implementation costs to harmonise the gas day start time would include the use of letters of agreement to vary the definition of "day" in GSAs and GTAs. Changes to each producer's systems such as metering, process history databases, billing and accounting will also be required.[115] No cost estimates were provided by the Australian Petroleum Production & Exploration Association (APPEA).

APLNG indicated it would cost approximately $10 million to align its operations with a new gas day start time of 6.00 am AEST. This cost relates to onsite reprogramming of both gas and water meters and associated equipment at over 1,000 gas wells across southeast Queensland as well as changes to control systems. Changes would also have to be made to 13 gas compression and processing plants. APLNG noted that during the period that metering was gradually converted to a new gas day start time, which may take between nine to 12 months, manual reconciliations of all metering data would have to be performed. This would also contribute to overall implementation costs.[116]

QGC has also estimated a cost of approximately $10 million to make the required changes to operate on a new a gas day start time of 6.00 am AEST.[117] This cost relates to: onsite reprogramming of well head gas and water meters across a large area of

113 ibid, p. 3.

114 ibid, p. 4.

115 APPEA, submission on the consultation paper, p. 1.

116 APLNG, submission on the consultation paper, p. 2.

117 QGC, supplementary submission on the consultation paper, p. 1.

Queensland;[118] and reprogramming meters at a number of field compression station gas meters, central processing plants, delivery and receipt points on pipelines and gas meters within the LNG processing plant. In total, QGC expects to adjust 2,760 devices.

QGC asserts that all metering facilities from the well head must align with the new gas day start time due to the vertically integrated nature of the LNG project and the physical and contractual linkages to the domestic gas market. These characteristics give rise to specific network system balancing requirements which requires that the entire QGC system operates on the same gas day. If the gas day start time on pipelines change, QGC considers changes would be required across its systems so that it could appropriately invoice domestic customers and allocate gas and revenues to joint venture partners and other group entities. QGC noted:

- Fiscal meters, which have daily measurement clocks, would require resetting to the new gas day start time. Otherwise invoicing and allocations could not be performed satisfactorily for audit purposes and to a level of accuracy expected by the joint venture partners or customers.[119]
- Well head meters must be reset to the new gas day start time so that production levels can be balanced against the relevant fiscal meters and the appropriate gas and revenue allocations to joint venture partners that own the various tenements. QGC anticipates that disputes would emerge between parties if the well head and fiscal meters were not aligned to the same gas day.

QGC also noted there would be additional costs, not factored into its $10 million estimate, relating to managing the balancing issues during the period that meters are being progressively changed. The negotiation and amendment of various contracts has been estimated to cost QGC $100,000 to $200,000.[120]

GLNG has indicated to the AEMC that it has installed many meters that can be remotely read and programmed. This would allow it to implement a change to the gas day to its meters at a cost significantly less than that indicated by both APLNG and QGC. Some legal costs would also be incurred.

Transmission pipelines

APA has estimated a total cost of $1.5 to $2 million to implement changes to its affected east coast transmission assets.[121] The changes required to implement a new gas day start time identified by APA include:[122]

- changes to flow computers at receipt and delivery points[123]

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118 The *Petroleum and Gas Act (2004)* (Qld) requires accurate gas and water metering. ibid, p. 2.

119 ibid.

120 ibid.

121 APA's key transmission assets in South Australia, New South Wales and Queensland include: SEA Gas Pipeline, Moomba-Sydney Pipeline, Roma-Brisbane Pipeline, South West Queensland Pipeline, Carpentaria Gas Pipeline and the Wallumbilla-Gladstone Pipeline.

122 APA, submission on the consultation paper, p. 4.

123 At each custody transfer point on transmission and distribution pipelines, a flow meter measures the flow rate or quantity of gas moving through a pipe. The measured gas volume and flow is

- variations to all existing GTAs
- changes to business processes and procedures
- changes to IT systems.

Jemena has estimated a one-off cost of $550,000 to implement changes related to the Eastern Gas Pipeline and the Queensland Gas Pipeline. These costs relate to:[124]

- onsite coding changes to flow computers at each receipt and delivery point
- making software changes to its shipper management system which is used to manage commercial relationships, including billing
- potentially significant costs related to drafting and executing variations to all existing GTAs.

Jemena noted that its initial cost estimates may underestimate actual costs given the on-site changes would be needed across a number of distribution and transmission assets over a very large geographic area at the same or very similar time and the potential for 'surge pricing'.[125]

Distribution pipelines

AGNL and Allgas estimated costs to their businesses of $140,000 and $50,000 respectively. Both service providers indicated that implementation of the change in the gas day start time will necessitate:[126]

- reprogramming flow computers for custody transfer meters at each sub-network gate station on their distribution pipelines
- reprogramming all large volume customer interval meters in Queensland, South Australia, and New South Wales, including those outside the STTM.

AGNL has 80 metering sites in Queensland, 30 in New South Wales and 150 in South Australia. Allgas has 110 sites in Queensland. AGNL and Allgas have advised that not all this work can be done remotely and most metering infrastructure will require a visit by technicians over a period of four weeks to make the necessary changes. Allgas noted that an approach to manage that meters will report data in respect of different gas days will be needed for the transition period.[127]

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corrected by a flow computer using analogue and digital signals from the flow meters and temperature, pressure and density transmitters. Flow computers produce instantaneous and cumulative data of the volume for each flow meter it monitors and creates a record of this volume on pre-programmed periods of time. Typically, telemetry equipment transmits data from on-site measurement equipment to a SCADA system to achieve remote monitoring of flow.

124 Jemena, submission on the consultation paper, pp. 5-7.

125 Surge pricing may occur where there is high demand and limited supply for a service within a certain period of time. An increase (or surge) in price occurs in response to the increased demand.

126 Submissions of the consultation paper: AGNL, p. 2; Allgas, p. 2.

127 Allgas, submission to the consultation paper, p. 2.

Jemena estimated that a one-off cost of around $450,000 to implement a new gas day start time on the New South Wales Jemena Gas Network (JGN) (and parts of the ActewAGL distribution pipeline).[128] These costs relate to:[129]

- changing the gas day start time on the server to which daily meter reads for its industrial customers are uploaded
- remote changes to onsite equipment followed by manual adjustments to equipment at up to 500 sites across New South Wales and the Australian Capital Territory
- modifications to 24 gas flow computers on the day of transition and that this will potentially need to be conducted on site
- external communications with all parties impacted by the change and amending agreements.

Jemena's estimated costs assume that AEMO would also amend the gas day start time to 6.00 am AEST in the Retail Market Procedures for the Australian Capital Territory.[130] Such a change would have a flow on effect of making changes in the Australian Capital Territory even though it is not part of any STTM or GSH hub. If the gas day start time remained at 6.30 am AEST in the Australian Capital Territory, Jemena indicated that its costs may double because it would then be required to replicate existing hardware, software and support to accommodate JGN and ActewAGL operating on different gas days. In addition, Jemena would face the ongoing issue of a half hour (between 6.00 am and
6.30 am AEST) of unaccounted for gas.[131] As noted above, the large number of geographically dispersed sites and the potential for surge pricing could also increase actual costs for Jemena's distribution pipelines.

Both JGN and ActewAGL pipelines are subject to full regulation by the AER. The access arrangements in place set out the terms and conditions of the reference services provided. This includes that the gas day start time is 6.30 am AEST. A change to the terms and conditions of the reference services will require Jemena to carry out a consultation process with its users.[132]

Shippers

No cost estimates have been provided by shippers, however, some have expressed a view on the impact of implementing a new gas day. Shippers have indicated that the cost to their businesses of implementing a new gas day start time in the STTMs and GSH would not be material although making the necessary changes would be likely to take some time.[133] The costs incurred to implement a new gas day would be related to IT system changes and operational procedures. According to Origin, the largest cost is

128 Jemena, submission on the consultation paper, p. 4.

129 ibid. pp. 4-7.

130 ibid, p. 2.

131 Jemena, submission on the consultation paper, pp. 5-6.

132 ibid, p. 6.

133 Submissions on the consultation paper: AGL, p. 2; Stanwell, p. 2; EnergyAustralia, p. 2.

likely to be legal fees arising from changing GSAs and GTAs.[134] AGL noted that most shippers will be in the same position and so no one shipper should be particularly disadvantaged by the change.[135]

Summary

A summary of the cost information provided by various stakeholders is set out in the table below.

Table 4.1 Summary of implementation costs

Business	Major cost items	Estimated costs
Allgas (owns and operates distribution pipelines in Qld)	Changes to flow computers and interval meters at a total of 110 sites Changes and testing of IT systems Amendments to contracts	$50,000
AEMO (market operator for the STTM, GSH and DWGM, and pipeline operator for the DTS)	Changes to infrastructure, IT systems, procedures and processes and the GSH exchange agreement	$100,000
Australian Gas Networks Ltd (owns and operates distribution pipelines in Qld, NSW and SA)	Changes to flow computers and interval meters at a total of 260 sites Changes and testing of IT systems Amendments to contracts	$140,000
Jemena - distribution (owns and operates distribution pipelines in NSW and ACT)	Changes to flow computers and interval meters at up to 500 sites Changes and testing of IT systems Amendments to contracts	$450,000
Jemena - transmission (owns and operates transmission pipelines including the QGP and EGP)	Changes to flow computers at receipt and delivery points Changes to IT systems Amendments to contracts	$550,000
APA (owns and operates transmission pipelines across all east coast states)	Changes to flow computers at receipt and delivery points Changes to IT systems Amendments to contracts	$1.5-$2 million

134 Origin, submission on the consultation paper, p. 1.

135 AGL, submission on the consultation paper, p. 2.

Business	Major cost items	Estimated costs
QGC (Qld coal seam gas producer, supplying gas to domestic customers and for export via their Curtis Island LNG facility)	Change to well head gas and water meters, gas meters at compression and processing plants, pipeline gas meters at delivery and receipt points, gas meters within the LNG processing plan Changes to IT systems Amendments to contracts	$10 million
APLNG (Qld coal seam gas producer, supplying gas to domestic customers and for export via their Curtis Island LNG facility)	Change to well head gas and water meters and gas meters at compression and processing plants Changes to IT systems Amendments to contracts	$10 million

4.2.2 Second round consultation

Stakeholders did not provide any information on the costs of implementing the draft rule to harmonise gas day start time in the STTM and GSH with the DWGM gas day start time of 6.00 am AEST. Shell confirmed that if the draft rule was made it would be required to update its metering systems throughout the QGC Joint Venture Project at an estimated cost of $10 million.[136]

4.3 Commission's analysis

Changes to the gas day start time under the proposed rule are limited to activities of participants in the STTM and GSH. The proposed rule did not place regulatory obligations on distribution pipeline operators, owners of coal seam gas facilities, producers, or transmission pipeline operators outside the STTM and GSH to adopt a new gas day start time. However, for the purpose of providing information on costs, some stakeholders included costs arising from making changes to facilities outside or not connected to the facilitated markets. Such an approach is consistent with the views expressed by some stakeholders that if a change in the gas day is to be made, then it should apply to the east coast gas market generally and not be confined to the facilitated markets.[137]

Specifically, some stakeholders have provided information on implementing a new gas day start time across the east coast on the assumption that:

- AEMO will change the gas day start time in the Retail Gas Market Procedures (for Queensland, New South Wales and the Australian Capital Territory) to align with

136 Shell, submission on the draft rule determination, p. 1.

137 See section 3.2 of this final rule determination.

the facilitated markets which will then require distribution pipeline operators to make changes to their metering infrastructure and systems[138]

- coal seam gas producers will have a commercial incentive to align their metering arrangements with the facilitated markets.

It is evident from the information provided by stakeholders that a change to the gas day in the facilitated markets will have a significant impact on industry participants. The direct impact of the proposed rule may result in direct implementation costs of approximately $3 million to be incurred.[139]

However, as raised by stakeholders, the full benefits of implementing a common gas day arise when other market reforms take hold in the future and participants across the east coast gas market adopt a 6.00 am AEST start time for a gas day. Under this scenario, the proposed rule, subsequent procedure changes, and changes made by coal seam gas producers will, in total potentially lead to implementation costs of approximately $25 million.

The Commission considers that these cost scenarios are also relevant for the final rule. This is because both the proposed rule and the final rule only capture participants' activities to the extent they are participating in the STTM and GSH and therefore certain costs would be incurred under either rule.

Of the potential implementation costs under the scenario that a change to the gas day is made by many participants across the east coast in response to a rule change, procedure changes and commercial incentives, the most significant implementation costs can be attributed to the coal seam gas producers with low levels of automation in their metering infrastructure. However, it should be noted that some of these costs are driven by the particular requirements of the commercial structures of the businesses.

138 In relation to regional subnetworks, such as Wagga, Wide Bay, Port Pirie and Mildura, it would be outside the scope of this rule change process to require AEMO to make changes to the gas day start time in these networks. However, AEMO can consider the issue when it consults and makes changes to the Retail Market Procedures to be consistent with the new gas day start time in the STTM and GSH under the NGR. These consideration could include any inefficiencies that may occur if the regional sub-networks are not also harmonised to a 6.00 am AEST gas day start time.

139 Based on costs for AEMO, certain APA and Jemena transmission pipelines and shippers using those pipelines.

5 Other issues

This chapter sets out the COAG Energy Council's views, stakeholder views and the Commission's analysis with respect to:

- the costs and benefits of implementing alternative gas day start times in the facilitated markets
- the closing time for bids and offers in the STTM
- whether a prescribed cost recovery mechanism is appropriate.

5.1 Alternative gas day start times

5.1.1 COAG Energy Council's views

The COAG Energy Council considers that aligning the STTM and GSH gas day start times with the Victorian DWGM gas day start time of 6.00 am AEST will minimise the cost of achieving a harmonised gas day across all the facilitated markets. This is because there will be no change in the DWGM which has the greatest number of participants and hosts significant metering infrastructure.[140]

5.1.2 Stakeholder views - first round consultation

A number of stakeholders considered alternative gas day start times should also be costed so that the least cost option could be implemented in a rule change.[141] Stakeholder submissions presented divergent views on whether 6.00 am AEST was the optimal gas day start time for markets across the east coast:

- A number of stakeholders including APA, APPEA, EnergyAustralia, GDF, the MEU and Stanwell supported the proposed rule to harmonise the gas day start time to 6.00 am AEST.[142] However, APA noted that a 6.00 am AEST gas day start time may present issues should the gas day start time be extended to Western Australia.[143]
- AGL supported alignment of the gas day across markets starting at the Sydney and Adelaide STTM time of 6.30 am AEST on the basis that this is currently the most widespread time among market participants.[144]
- QGC and APLNG indicated they would strongly prefer a gas day start time of 8.00 am AEST (or later). APLNG submitted that "the intent of the "Gas day" in the gas market/contract was to align with any required operational changes with the start of a normal work day". APLNG therefore expressed concern regarding the ongoing operational and safety impacts of shifting the gas day start time to

140 COAG Energy Council rule change request, 19 November 2015, p. 9.

141 Submissions on the consultation paper: APGA, p. 2; Jemena, pp. 2-3; QGC, p. 1; APLNG p. 2; APLNG supplementary, p. 2.

142 Submissions on the consultation paper: APA, p. 4; APPEA, p. 1; Energy Australia, p. 1; GDF, p. 2; MEU, p. 1; Stanwell, p. 1.

143 APA, submission on the consultation paper, p. 1.

144 AGL, submission on the consultation paper, p. 1.

6.00 am AEST in Queensland. It noted the "start of day safety meeting" currently takes place at 6.00 am AEST to allow operators time to travel to remote locations before the 8.00 am AEST start of the gas day.[145]

However, AEMO submitted that the cost of changing the gas day start time in the Victorian DWGM would be far more significant than the cost of making a change to the STTM and GSH gas day start time. This is because, compared to the STTM, there are many market and operational activities carried out during a gas day in the DWGM, many of which are hard coded to occur at a specific time of day. As a result, there would be more material changes to the DWGM systems.[146] AEMO's preliminary estimate for making these changes to the DWGM systems was $10 to 20 million.[147]

AEMO also considered there would be significant market implications if the DWGM gas day start time was changed from 6.00 am AEST.[148]

In addition to system changes to operate the DWGM, some changes would also need to be made to the Declared Transmission System (DTS). Based on its initial discussions with APA, AEMO indicated making changes to metering on the DTS could cost up to $1 million.[149]

5.1.3 Draft rule determination

The Commission made a draft rule determination, consistent with the proposed rule, to harmonise the gas day start time in the STTM and GSH markets with the Victorian DWGM gas day start time of 6.00 am AEST. The Commission expected this to be the least cost option for harmonising the gas day start time in these facilitated markets.

5.1.4 Stakeholder views - second round consultation

AEMO, AGL, APA and Engie expressed support for harmonising the gas day start time of the facilitated markets to the DWGM gas day start time of 6.00 am AEST.[150]

Consistent with its response to the rule change request, AEMO elaborated further on its reasons for supporting a 6.00 am AEST gas day start time. AEMO submitted that a 6.00 AEST am gas day start time in the DWGM is preferable because it supports efficient linepack management and spot market pricing. It also allows participants, who typically make daily nominations, to capture the entire morning peak within a single gas day and scheduling interval.[151]

AEMO also provided revised estimates of the costs for changing its systems if a change in the gas day start time from 6.00 am to 8.00 am AEST was required in the DWGM.

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145 APLNG, submission to the consultation paper, p. 1.

146 AEMO, submission on the consultation paper, p. 3.

147 AEMO email to AEMC, 25 May 2016.

148 AEMO, submission on the consultation paper, p. 3.

149 ibid. The AEMO and APA cost estimates relating to changing the Victorian gas day do not include costs relating to contracts, distribution connected meters, or any changes to production or storage facilities.

150 Submissions on the draft rule determination: AEMO, p. 1; AGL, p. 1; APA, p. 1; Engie, p. 1.

151 AEMO, submission on the draft rule determination, p. 1.

AEMO estimated its costs would be approximately $1 million, assuming that only the gas day start time is shifted to 8.00 am AEST and that the number and duration of scheduling intervals remained the same. However, AEMO also commented that it expected that changes to the number and duration of schedules may need to be considered if the gas day start time in the DWGM was changed to 8.00 am AEST because of the resulting impact it would have on other activities during the day. If changes were made to the scheduling intervals, the cost to change to 8.00 am AEST would increase materially, particularly because it would include making changes to the settlement systems.[152]

Shell reiterated its previous explanation that there are operational reasons for the Queensland gas day commencing at 8.00 am AEST. It asserted this is driven, in part, by safety considerations such as minimising the need for operational staff to travel to sites during non-daylight hours.[153] Shell also considered that while it is likely, it is still unclear whether a 6.00 am AEST gas day in Victoria will be as important to managing the gas market and ensuring system security if the DWGM changes to a southern hub trading model with a continual balancing regime.[154]

5.1.5 Commission analysis

The rule change request clearly sets out the COAG Energy Council's intention to change the gas day start times in the STTM and GSH to 6.00 am AEST to align with the Victorian DWGM. However, not all stakeholders considered that the proposed time would be the most appropriate for the east coast gas market. Two alternatives: 6.30 am and 8.00 am AEST were identified. The Commission's consideration of these two options is set out below.

6.30 am AEST gas day start time

Adopting 6.30 am AEST as the start time for the gas day would avoid the costs associated with modifying metering infrastructure in South Australia, New South Wales and the Australian Capital Territory. However, a 6:30 am AEST gas day start time would impose significant costs in the Victorian DWGM and in Queensland.

The DWGM systems are hourly based, on the hour, so shifting the Victorian arrangements by the half hour (to every hour on the half hour) would involve extensive changes for AEMO's and participants' systems. These changes would be complex to operate and costly to implement. The cost to make this change would be greater than making a change to a different ‘on the hour’ gas day start time. There would also be additional metering costs for participants in Victoria.

There would also be significant costs related to changes to metering infrastructure in Queensland. The AEMC understands that some metering infrastructure has been in place for some time (up to 40 years) and collects hourly data each day, starting at 8.00 am AEST. In addition, most of the installed flow computers that form a critical element of the metering infrastructure are unable to be reprogrammed to measure flows

152 AEMO, submission on the draft rule determination, p. 2.

153 Shell, submission on the draft rule determination, p. 2.

154 ibid.

starting at half past the hour, hourly. If participants outside the STTM and GSH also adopted a 6.30 am AEST start time for their gas day the costs of around $20 million previously noted for the LNG participants would be expected to be incurred.

8.00 am AEST gas day start time

Under this alternative, the facilitated markets, including the Victorian DWGM, would harmonise with the 8.00 am AEST gas day start time of the Brisbane STTM and the Wallumbilla GSH. The principal benefits of an 8.00 am AEST gas day start time are the avoided costs related to modifying coal seam gas metering infrastructure as well as the Brisbane STTM and the Wallumbilla GSH. These potential savings may be substantial. As set out above, the Queensland LNG businesses have estimated a cost of approximately $20 million to make changes to their metering infrastructure and systems.

The Commission has considered the implications of an 8.00 am AEST gas day start time for the Victorian DWGM and for an alternate market design consistent with the AEMC's recommendations in its ongoing review of the Victorian DWGM.[155]

The AEMC published its draft final report on the review of the Victorian DWGM in October 2016. The draft final report investigates the issues currently facing the DWGM and sets out the Commission's recommendations to address these issues. The recommendations principally involve introducing a new set of arrangements to establish a southern hub for trading gas across the DTS. This would involve substantially reforming the DWGM to introduce:

- new trading arrangements which include a continuous balancing regime to give participants greater ability to manage price risk and improve longer-term price signals to facilitate investment decisions
- explicit capacity rights for the use of pipeline infrastructure, which would enable investment decisions to be driven by market participants' purchases of rights, improving decision making and reducing risks to consumers.

Implementation cost impacts

There are likely to be significant implementation costs and market impacts in Victoria in changing to a 8.00 am AEST gas day start time regardless of whether the DWGM is retained or if a southern hub is implemented.

Under existing DWGM arrangements, AEMO has estimated the cost of changing the DWGM systems including to changes to scheduling intervals and the settlement systems would be likely to give rise to implementation costs materially greater than $1 million.

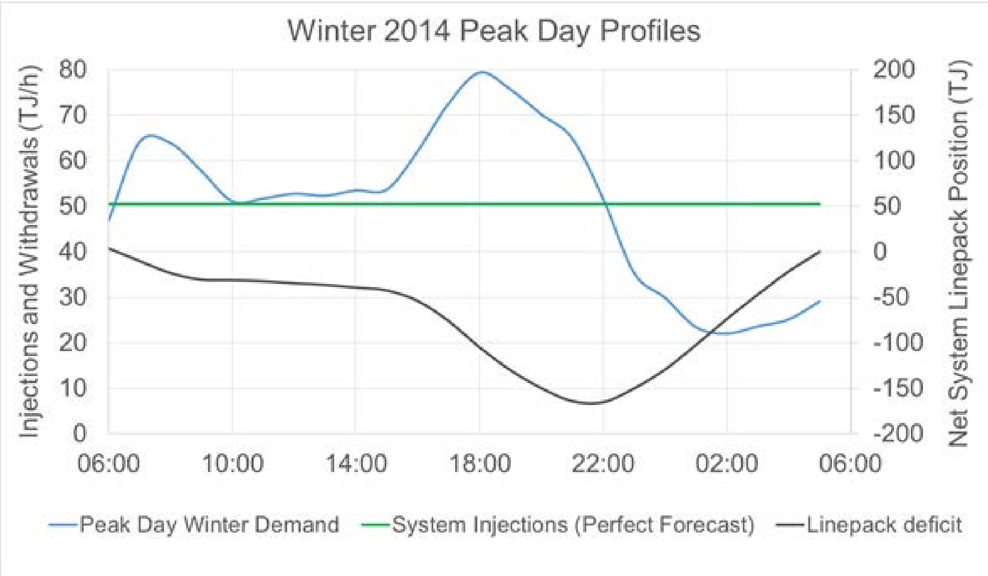
In addition, the Commission expects that transmission and distribution pipeline operators would incur at least $2 million in costs to make modifications to metering infrastructure in Victoria, New South Wales, South Australia and the Australian Capital Territory.

155 AEMC, *Review of the Victorian declared wholesale gas market*, Draft final report, 14 October 2016.

Operational and market issues

A change to a 8.00 am AEST gas day start time creates operational and market issues in Victoria due to the diurnal demand profile of a morning and evening peak. Figure 5.1 illustrates a typical peak winter profile in Victoria. The winter peak, primarily caused by high heating demand by residential customers, utilises most of the pipeline linepack[156] on the DTS. This is illustrated by the drop in the 'linepack deficit' curve in the figure. The summer profile is flatter with peaks and troughs a little earlier, but in general is broadly similar.

Figure 5.1 Victorian winter 2014 peak day profile - total system injections, demand and linepack



Source: Provided to AEMC by AEMO.

In the DWGM, market participants are required to provide to AEMO injection bids, controllable withdrawal bids and forecasts of uncontrollable withdrawals for the whole of the gas day one hour ahead of the gas day start time. Market participants make their injection bids, controllable withdrawal bids and forecasts for uncontrollable demand on the basis of their own forecasts of the gas market for the whole of the gas day.

The DWGM has five schedules throughout the day. One hour ahead of each schedule, market participants are able to adjust their bids and forecasts for the remainder of the gas day based on their own forecasts of the gas market for the remainder of the gas day.

Market participants' bids and uncontrollable demand forecasts are therefore made for the following periods at each schedule: [157]

- schedule 1: one hour to 25 hours in advance

156 Linepack is required to manage the difference between injection and off-take profiles across the day, but the Victorian DTS has a very limited range of usable linepack on any given day. The linepack on the system follows the daily swing of the customer demand profile by about 1-2 hours. Pressures on the system in general reflect this swing, with the critical times being the troughs to ensure that minimum pressures at off takes are not breached, and maximum over pressures are not exceeded to avoid damage to plant, especially at the production end of the system.

157 The forecast for each period relates to the remaining balance of the gas day.

- schedule 2: one hour to 21 hours in advance
- schedule 3: one hour to 17 hours in advance
- schedule 4: one hour to 13 hours in advance
- schedule 5: one hour to nine hours in advance.

All things equal, market participants' forecasts are likely to be more accurate the shorter the time between the forecasts being made and the time of the event. Forecasts made one hour in advance for the start of a schedule are likely to be most accurate, while forecasts made 25 hours in advance (one hour before the start of the gas day for the end of the gas day) are likely to be least accurate.

Furthermore, one hour ahead of the start of the gas day, AEMO makes a forecast of the linepack position at the start of the gas day. It will also forecast the start of schedule linepack one hour ahead of each schedule throughout the day. AEMO's forecast of linepack at the start of the next schedule is likely to be more accurate if the rate of change of demand for the coming hour is likely to be low. That is, at times where demand is unlikely to change significantly it is easier to forecast linepack levels one hour hence.

On the basis of market participants' bids and forecasts, events that have already occurred on the gas day, and AEMO's forecasts of the linepack position at the start of the schedule, AEMO's market clearing engine schedules market participants. In turn, this determines settlement outcomes, such as the market price and any subsequent imbalance charges, deviation charges, ancillary payments and uplift charges.

Inaccuracies by both market participants in making their bids and forecasting of uncontrollable withdrawals, and by AEMO in forecasting the start of schedule linepack, result in financial risks for market participants. Inaccurate forecasts will:

- increase the volatility of the price of the first schedule and subsequent schedule prices, in turn increasing market participants' exposure to deviation payments
- increase the probability that a market participants' actual injections and withdrawals differ from those scheduled, increasing market participants' exposure to both surprise uplift and deviation payments.

Inaccurate forecasts also give rise to inefficient scheduling across the DWGM. For example, a more costly combination of gas may be scheduled than would have occurred had forecasting been accurate. Furthermore, inaccurate forecasts may also create operational issues, requiring AEMO to make more substantial changes to flows of gas throughout the day in order to meet demand and maintain pipeline integrity.

In light of these operational needs of the DTS and the DWGM a 6.00 am AEST gas day start time is preferable for a number of reasons. Firstly, a large proportion of demand occurs at the start of the Victorian gas day. Consequently:

- The morning peak occurs near the start of schedule 1, and will likely to be relatively accurately forecast in that schedule
- The morning peak demand is known for schedules 2 to 5, and will be reflected with the benefit of hindsight in these schedules

- There will be low demand for gas at the end of schedule 5, meaning that the negative impacts of relatively inaccurate forecasts for this time will be minimised.

Secondly, there are relatively low rates of change in demand at 5.00 am, one hour prior to the start of the first schedule. This improves the likelihood that AEMO’s linepack forecast for the start of the gas day is accurate.

In contrast, an 8.00 am AEST gas day start time would mean that the start of the morning peak, between 6.00 am and 8.00 am AEST, would be at the very end of the gas day. Consequently:

- The morning peak occurs at the end of schedule 5, and will likely to be relatively inaccurately forecast in both the first schedule and each subsequent schedule. This effect is most notable in the fifth schedule which is longer than the others, and hence likely to be least accurate.
- AEMO’s forecast of linepack for the start of the day will be made at 7.00 am AEST, one hour prior to the start of the gas day, at a time when the likely rate of change in demand for the coming hour is relatively large. Consequently, the forecast is more likely to be inaccurate.

These inaccuracies in the forecasts would be likely to give rise to greater operational and market impacts in the DWGM, as described above. These operational and market issues do not arise significantly in Queensland because demand for gas is not diurnal.

If a southern hub model is adopted, a continuous balancing regime may mitigate some, but not all, of the market impacts of commencing the gas day at 8.00 am AEST during the morning peak. Despite a continuous balancing regime providing some additional flexibility to AEMO and market participants, there are likely to be some market activities that still occur on the basis of a gas day. These activities, as well as the operation of the DTS, may be affected by similar forecasting inaccuracies to those set out above in relation to the DWGM.

Conclusion

The Commission has concluded that 6.00 am AEST is the least cost option to achieve a harmonised gas day start time across the east coast facilitated gas markets.

In reaching this conclusion, the Commission considers that the avoided costs and operational benefits to participants in Queensland from retaining an 8.00 am AEST gas day start time would be likely to be more than offset by the implementation, operational and market impacts that would be incurred in changing the Victorian DWGM gas day start time or establishing a southern hub with an 8.00 am AEST gas day start time.

5.2 Closing time for bids and offers in the STTM

5.2.1 COAG Energy Council's views

The COAG Energy Council did not propose changes to the timing of certain intra-day activities in the STTM, such as the closing time for bids and offers, other than those that would arise as a consequence of changing the gas day start time.

5.2.2 Stakeholder views - first round consultation

Stanwell suggested harmonising the "market close" of the STTM hubs to 1.30 pm AEST (the current Brisbane time). Stanwell argued this would provide gas fired generators with adequate time to review AEMO's 12.30 pm AEST predispatch forecast for the national electricity market and then trade gas prior to the STTM "market close".[158]

5.2.3 Draft rule determination

The draft rule did not alter the timing of any intra-day activities in the facilitated markets, including the closing time for bids in the STTM, other than those changes resulting from change in the gas day start time.

5.2.4 Stakeholder views - second round consultation

In response the draft rule determination, Stanwell reiterated that the closing time for bids in the STTM should be made 1.30 pm AEST. Stanwell argue this would provide gas fired generators the ability to refine their operational profiles following the AEMO's 12.30 pm AEST predispatch forecast for the national electricity market and to buy or sell gas in the one hour before bids in the STTM closed. Stanwell disagreed with the AEMC's assertion in the draft rule determination that retaining the 1.30 pm AEST close time would impose additional costs on AEMO and claimed that:[159]

> “Even if benefits were limited to gas fired generators, these are a large and important segment of the gas market, with the most variable demand profile of all participants in the STTM and gas supply hubs.”

5.2.5 Commission analysis

Rule 410 in the NGR requires ex ante bids and offers in the STTM to be made no later than 5.5 hours after the start of the gas day that precedes the gas day to which the bid or offer relates. Currently, this means that offers and bids can be submitted to AEMO up to 12.00 pm AEST the day before the relevant gas day in Sydney and Adelaide, and up until 1.30 pm AEST in Brisbane. Under the final rule, which harmonises the gas day start time of all east coast facilitated markets to 6.00 am AEST, bids and offers will need to be submitted for all STTM hubs at 11.30 am AEST the day before the relevant gas day.

The Commission acknowledges there may be benefits to making the closing time for bids and offers 1.30 pm AEST for all STTM hubs so that gas fired generators could trade gas following AEMO's pre-dispatch forecast for the NEM. However, the Commission considers this change in the framework for the STTM, which may have more far reaching implications, would be more appropriately considered in the context of broader reforms to the STTM which will be progressed by the GMRG. The Commission has therefore not made a final rule that changes the timing of intra-day day activities, other than where these changes arise as a consequence of changing the gas day start time.

158 Stanwell, submission on the consultation paper, p. 1.

159 Stanwell, submission on the draft rule determination, p. 3.

5.3 Cost recovery

5.3.1 COAG Energy Council's views

The COAG Energy Council's rule change request recognised that there would be one-off costs associated with harmonising the gas day start times in the facilitated markets. However, it did not propose the implementation of a cost recovery mechanism to share the costs of implementation across market participants.

5.3.2 Stakeholder views - first round consultation

A number of stakeholders raised concerns that the costs and benefits arising from harmonisation of the gas day would be distributed unevenly across participants and jurisdictions. It was suggested that a mechanism should be included in the NGR to redistribute the costs of implementation across the market so that those participants who benefit from the rule change contribute to the cost of making the change possible.

For example, APA and APGA commented that the benefits of harmonising the gas day start time will accrue to those market participants that actively participate in multiple facilitated markets. Specifically, these parties will benefit through the simplification of daily market processes and being able to optimise cross market trading opportunities. However, APGA expressed concern that participants such as gas pipelines, small producers and retailers are likely to face costs without accruing such benefits. As a result, some form of cost recovery mechanism should be implemented.[160] APA also commented that:[161]

> “Given that the benefits from the proposed rule will largely flow to trading participants and these costs are not largely capable of being recovered through regulatory or contractual avenues, APA would expect that the Rule contemplates a cost recovery mechanism for facility operators to recover such costs.”

Jemena also raised concerns that costs and benefits would not be equally distributed, and submitted that:[162]

> “A more preferable rule should include an appropriate cost recovery approach. For example, the costs incurred by market participants as a result of the rule change could be recoverable from the Australian Energy Market Operator (AEMO) and then via market fees. Otherwise a situation will arise where benefits accrue to market participants in all jurisdictions, but the costs of the change are borne by customers or businesses within a subset of jurisdictions.”

QGC asserted that if there was no clear gas day start option that minimised the costs of implementation, it would be inappropriate to arbitrarily impose significant costs on one set of market participants through making a rule. It considered some form of compensation for those parties incurring costs would be appropriate. While QGC

160 Submissions on the consultation paper: APA, pp. 4-5; APGA, p. 2.

161 APA, submission on the consultation paper, pp. 4-5.

162 Jemena, submission on the consultation paper, pp. 1-2.

acknowledged that there are likely to be benefits from harmonising the gas days across the east coast market, in its view the benefits would not outweigh the costs to its business if the costs of making necessary changes were not shared across the market.[163]

On the basis that implementing the proposed rule would create an asymmetry in costs and benefits, several stakeholders including APA, APGA, QGC and Jemena indicated that making changes to GTAs and GSAs through bilateral negotiations may be costly and difficult to achieve. This is because 'change of law' provisions may not be triggered in GTAs and GSAs.[164] APA suggested that the only way to achieve contractual variations in a timely and effective manner would be through a "wider legislative change" and subsequent contractual provisions to deal with that change.[165] AEMO, APGA and Jemena also made similar suggestions – that a law or rule change be made to address the concerns that not all pipeline operators and contractual arrangements would be required to use a harmonised gas day start time under the proposed rule. If such a change could be made then this may make the subsequent changes to contracts less costly to make.

Similarly, APLNG asserted that there is only an indirect link between a change in the GSH gas day start time and its contracts to supply gas to its domestic customers. It expressed doubt it could pass on any of its implementation costs to its customers under these circumstances. However, at the same time, APLNG may be expected to accept cost pass throughs under its GTAs with pipeline operators in relation to the pipeline's costs for changing to a new gas day start time. For these reasons, APLNG suggested that consideration should be given to sharing the cost of implementation across all east coast gas market participants.[166]

5.3.3 Draft rule determination

The draft rule included a requirement that allocation data be derived from metering data consistent with the STTM gas day, which, in part, was to provide greater certainty that change in law provisions could be invoked in relation to passing through the cost of changing meters. The draft rule did not include any cost recovery mechanism as requested by some stakeholders.

5.3.4 Stakeholder views - second round consultation

APA observed that the additional data provisions requirements only apply to the STTM. It commented that:[167]

> "This means that this rule change would only compel a change to the gas day in a subset of the total number of contracts that would require changing in order to achieve a standard gas day across the east coast. Other contracts would need to be changed through commercial negotiation and shippers

163 QGC, submission on the consultation paper, p. 2; QGC, supplementary submission on the consultation paper, p. 2.

164 Submissions on the consultation paper: APA, p. 4; APGA, p. 1; QGC, p. 2; Jemena, p. 3.

165 APA, submission on the consultation paper, pp. 3-4.

166 APLNG, supplementary submission on consultation paper, p. 2.

167 APA, submission on the draft rule determination, p. 1.

may not agree. In this case, cost pass through provisions associated with change in law provisions may not be enacted."

A number of stakeholders considered the draft rule should have included a prescribed cost recovery mechanism to allow participants to recover the costs of implementing a harmonised gas day and reiterated concerns they had expressed in their submissions on the consultation paper.

Jemena and Shell asserted that it was inappropriate that participants in a subset of jurisdictions would incur the costs of harmonising the gas day across the east coast facilitated markets, when benefits would accrue to customers in jurisdictions that do not contribute to the cost.[168] Jemena claimed that this represents a cross-subsidisation which is allocatively inefficient and therefore inconsistent with the national gas objective. APA, Jemena and Shell suggested that the costs be distributed across the market based on the principles of "derived benefit" and "equity".[169]

Shell suggested that relevant precedents include areas of climate change policy, the National Gas Market Bulletin Board cost recovery arrangements, and "Payment for Closure" type proposals.[170]

5.3.5 Commission analysis

In response to stakeholder concerns regarding their ability to pass through costs relating to implementing the proposed rule, the Commission has considered whether the proposed rule:

- is likely to trigger change of law provisions to facilitate cost pass through arrangements under existing GTAs and GSAs
- is likely to trigger cost pass through arrangements for fully regulated pipelines
- whether a prescribed cost recovery mechanism in the NGR is appropriate.

Contractual cost pass through arrangements

The Commission understands that GTAs typically contain change of law provisions that provide for pipeline operators to pass through an increase in its costs to shippers where, in general terms, those costs are:

- incurred a result of a regulatory change[171]
- related to a service that is provided to that shipper.

In addition, the Commission understands that some, but not all, GSAs similarly include change of law provisions that provide frameworks for reaching agreement for amending a GSA to reflect changes in the regulatory framework.

168 Submissions on draft rule determination: Jemena, p. 2; Shell, p. 2.

169 Submissions on the draft rule determination: APA, p. 1; Jemena, p. 2; Shell, p. 2.

170 Shell, submission on the draft rule determination, p. 2.

171 For example, a change of law or change in subordinate legislation governing the energy market.

However, there may be GTAs and GSAs that do not include such provisions. Where there is no change of law provision included in such a contract, the Commission considers this is likely to reflect the agreed risk allocation between the relevant parties.

The Commission acknowledges that participants would benefit from certainty that changes to the gas day start time would trigger existing change of law provisions in GTAs and GSAs. This would assist pipeline operators in passing through certain costs associated with the change in the gas day. However, it notes that the proposed rule may not provide the level of certainty regarding the trigger of change of law provisions and cost pass through arrangements that some stakeholders seek.

STTM

The Commission has considered the ability of the proposed rule to support or provide clarity on the need to make changes to contracts and the subsequent recovery of costs. While the proposed rule changes the gas day start time in the STTM, it does not include a corresponding provision requiring gas allocation data to be based on metered quantities measured across the new gas day. However, because STTM prices and withdrawals are determined on a gas day basis, pipeline operators may face commercial and operational risks unless they change the relevant metering infrastructure to measure gas flows according to the new STTM gas day.

The Commission considers that the above issues related to cost pass through and change of law provisions in commercial arrangements are likely to be alleviated by introducing a rule that, in addition to amending the STTM gas day start time, includes a requirement that allocation data be derived from metering data consistent with the STTM gas day. More specifically, requiring allocation data to be made using metering data based on the new STTM gas day is likely to:

- enhance confidence in the accuracy of allocation data
- provide greater certainty of the triggering of change of law provisions under contracts and allow STTM pipeline operators to pass through costs resulting from changes to metering infrastructure.

Accordingly, the final rule provides that an STTM facility operator must ensure that:[172]

- the quantity of gas supplied to or withdrawn from a hub on a gas day using its STTM facility is measured and recorded over the period of time corresponding to the gas day or over shorter periods of time that, when taken together, correspond to the gas day
- the information provided to AEMO under rule 419 of the NGR by the allocation agent for its STTM facility is calculated using the quantities determined for a gas day in accordance with the above requirement.[173]

172 Rule 369A of the final rule.

173 Under rule 419, an allocation agent for an STTM facility must give AEMO an allocation notice for the immediately preceding gas day which includes the STTM facility allocation, the quantity of market operator service (MOS) gas and overrun MOS allocated to that facility, MOS step allocations and any other matters required by AEMO for its functions relating to the STTM as specified in the STTM procedures.

The inclusion of this rule enhances the likelihood that existing change of law and cost pass through provisions would be triggered as a consequence of the change in the gas day in the STTM (as compared with the proposed rule). The Commission recognises the rule would not impact on contracts relating to the usage of non-STTM facilities. Also, the terms of GTAs and GSAs are not uniform across the STTM and the exact manner in which such provisions would operate as a consequence of the change in the STTM gas day start time may vary between participants. Additionally, consistent with the existing framework under the NGR regarding STTM facility allocations, this additional rule regarding allocation data operates in respect of STTM facility operators and does not extend more broadly to distribution withdrawals.[174]

AEMO has stated that it will amend the gas day start time in the Retail Gas Market Procedures as well as the timing of daily market activities in the STTM Report Specifications to be consistent with any change in the gas day start time in the STTM.[175] Under the Retail Gas Market Procedures, STTM distributors collect meter data at regular intervals which they supply to AEMO in relation to a gas day for calculating the daily allocations made to STTM users.[176] Changes to the Retail Gas Market Procedures that reflect the use of a 6.00 am AEST start time for a gas day would provide STTM distributors with greater clarity on making any necessary changes to business processes and contracts. A change to the procedures may also provide service providers of fully regulated distribution pipelines with the ability to use a cost pass through provision included in their access arrangements. Arrangements for pipelines subject to full regulation in general are discussed further below.

GSH

Changes analogous to rule 369A of the final rule, which requires allocation data provided by allocation agents for STTM facility operators to be derived using metering data based on the new gas day, are not possible in respect of the GSH arrangements under the NGR. This is because the existing arrangements under the NGR do not contain similar provisions relating to allocation agents and the provision of allocation data as currently exists in relation to the STTM. This reflects the fundamental differences in the design and operation of the GSH compared to the STTM. Neither the NGR nor the exchange agreement set out any requirements regarding allocation arrangements. Instead, the exchange agreement only implicitly requires shippers using the GSH to have in place a GTA and any other necessary arrangements to enable the delivery and receipt of gas. Introducing a framework similar to the STTM would require significant changes to the GSH framework beyond the scope of this rule change process.

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174 Under rule 419 of the NGR, allocation notices (which contain information such as STTM facility allocations) are provided by allocation agents in respect of STTM facilities. Under rule 364 of the NGR, an STTM facility means an STTM pipeline, an STTM storage facility or an STTM production facility. As a result, allocation notice information does not capture withdrawals (such as distribution withdrawals) that are not register facility services performed in respect of STTM facilities.

175 AEMO, submission on the consultation paper, p. 4.

176 AEMO, *STTM Industry Guide*, p. 18.

The Commission recognises that the effect of the final rule is limited in regard to the GSH.[177] The final rule does not have the effect of mandating changes to the nomination, scheduling or allocation arrangements in underlying GTAs and GSAs. Counterparties to underlying GSAs and GTAs at GSH trading locations may need to amend the start time of the gas day (or equivalent period) in these agreements to avoid misalignments between the market gas day and the underlying contracts. The Commission considers AEMO and industry are best placed to manage these misalignments through:

- consequential amendments to the exchange agreement[178]
- bilateral arrangements between relevant parties and/or
- the standardisation of capacity contracts which is to be led by the GMRG.

Existing arrangements for regulated pipelines

There are existing regulatory arrangements that may address stakeholder concerns regarding cost pass through arrangements for fully regulated pipelines.

Rule 97 of the NGR provides for cost pass through events for fully regulated pipelines. A service provider of a fully regulated pipeline may include a cost pass through mechanism in the reference tariff variation mechanism of its access arrangement. Such a mechanism may provide for tariff adjustments to be made where a 'cost pass through event', as defined in the access arrangement, occurs. The details will vary from pipeline to pipeline, however, existing access arrangements may include a cost pass through event (such as a 'regulatory change event') that would capture certain costs resulting from changes to the NGR such as those made under the final rule.

Alternatively, in light of the delayed commencement date of the changes to the gas day start time under the final rule, service providers will have the opportunity to propose a suitable provision in the next scheduled revision process for their access arrangement prior to the commencement of the final rule. In either case, a service provider may be able to rely on these provisions to pass through the costs incurred in complying with the new gas day and recover those approved costs through reference tariffs.

Statutory cost recovery mechanisms

The Commission has also considered stakeholder suggestions that the final rule include a specific cost recovery provision in the NGR related to participants' implementation costs for modifying metering infrastructure. For a workable mechanism to be established, it is likely that the NGR would need to:

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177 Other than AEMO, participation in the GSH is voluntary. Shippers participate in the GSH in order to buy and sell products for physical delivery of gas. Pipeline operators are not parties to the exchange agreement (in that capacity) and, in contrast to the STTM, are not required by the NGR to give AEMO information about capacity rights.

178 Rule 540 of the NGR provides for the process that must be followed for AEMO to amend the exchange agreement. If it does not reject a proposal to amend the agreement (AEMO may reject proposals in certain limited circumstances), AEMO is required under rule 540 to consult with gas trading exchange members and any others affected persons in accordance with the process set out in the exchange agreement.

- specify which market participants were eligible to recover costs
- specify the parties that would be required to pay the approved costs
- include a clear definition of the costs that would be the subject of the mechanism
- set out information requirements regarding the evidence of incurred costs to be provided to a decision-maker
- determine an appropriate decision-making body to assess whether the claimed costs have been incurred and fall within the relevant definition
- include a mechanism to recover those costs from relevant parties.

The current cost recovery provisions in the NGR for certain Bulletin Board costs and STTM market operator service (MOS) costs provide examples of existing cost recovery mechanisms in the NGR. These frameworks operate to achieve cost recovery in contexts that differ from that considered under this rule change process. Nevertheless, they do indicate the administrative complexity and detailed processes that the relevant parties may be required to comply with under a prescribed cost recovery mechanism for gas day harmonisation.

It should also be noted that the Bulletin Board and STTM MOS arrangements relate to the recovery of recurring costs. In comparison, a framework included in the final rule would be in regard to one-off implementation costs.

On balance, the Commission considers that the cost of developing and implementing a cost recovery mechanism for the purpose of prescribing how parties recover one-off costs related to the gas day harmonisation rule change would be significant and may not result in the type of broad-reaching mechanism that appears to be envisaged by some stakeholders. In particular:

- There are limitations on the Commission's ability to make rules regarding producers, large gas users and pipelines that are not the subject of economic regulation. Such limitations present an obstacle to introducing a cost recovery framework with the potential reach proposed by certain stakeholders.
- Similarly, it would be difficult to identify or impose obligations under the framework on certain parties that are expected to benefit from harmonising the gas day to 6.00 am AEST.
- Each market may require a separate cost recovery mechanism. This would make it difficult for the relevant decision makers to consider the costs and their recovery on a broader east coast gas market basis. It would also exclude participants not in the facilitated markets from either seeking the recovery of costs or being required to pay costs.

Further, the Commission is of the view that parties allocate change of law risk when negotiating their contracts and that it would not be appropriate to amend the NGR to mandate a particular distribution of costs that impacts on these commercially agreed allocations. In light of the commencement date of the final rule, the Commission anticipates that parties negotiating new and renewed contracts prior to the commencement date will have the opportunity to consider the implications of the final rule.

6 Implementation of the final rule

This chapter sets out COAG Energy Council's view, stakeholder views and the Commission's analysis in relation to the timing considerations for implementation of the final rule.

In determining an appropriate commencement date, the Commission has considered the timeframes required for:

- transmission and distribution pipeline operators to plan and resource a program to reset field flow computers and any other relevant equipment
- market participants to modify business procedures and systems
- GTAs and GSAs to be amended if necessary
- AEMO to make any requisite changes to its retail market systems and consequential changes required to its procedures
- AEMO to consult on and make amendments to the GSH exchange agreement
- the indicative timeframes announced by the COAG Energy Council for completing other gas market reforms recommended by the AEMC in the east coast review.

6.1 COAG Energy Council view

In its rule change request, the COAG Energy Council noted that:

- a number of steps would need to be undertaken by AEMO and industry to implement a harmonised gas day start time including operational, commercial and procedural work
- an adequate lead time would be required for AEMO and industry to implement these changes
- consideration would need to be given to minimising disruption during the changeover period and how other transitional arrangements would be best managed.[179]

6.2 Stakeholder views - first round consultation

6.2.1 The transition period

In response to the rule change request, a number of stakeholders expressed the view that a transitional period, ranging from "a few months" to twelve months would be needed by industry participants to prepare for the introduction of a new gas day start time.[180]

Some stakeholder submissions on the consultation paper suggested a market institution such as the AEMC or AEMO would be needed to manage the transition process to a

179 COAG Energy Council rule change request, 19 November 2015, p. 10.

180 Submissions on the consultation paper: AGL, p. 2; APLNG, p. 2; AEMO, p. 4; APA, p. 5; AGNL, p. 2; Allgas, p. 2.

new gas day start time.[181] In contrast, AEMO commented that under the proposed rule there are no measures that could be taken by a market institution to ensure there is a harmonised implementation of the gas day start time.[182]

6.2.2 Maximising the benefits

In response to the rule change request, a number of stakeholders commented that a harmonised gas day will be relevant for the east coast gas market when the anticipated market reforms regarding the short term trading of capacity and gas occur in the future. For example, APPEA stated that a harmonised gas day across the markets would "encourage more efficient trading and further development of liquidity".[183] APGA also commented that a harmonised gas day "seems to be a sensible step to support greater connectivity and liquidity in the market as a whole".[184] Engie regarded gas day harmonisation as "one of a number of pre-conditions to supporting the growing interconnectedness between gas markets".[185] EnergyAustralia opined that "aligning the gas day could enhance the interconnectedness of the facilitated markets and participants' ability to readily trade between regions".[186]

Other stakeholders expressed more specific views on the connection between the proposed rule and other gas market reforms. For example, APLNG stated:[187]

> "Until AEMC's proposed Stage 2 transportation changes (contract standardisation, day-ahead capacity auction) are implemented, APLNG would receive limited benefit of a gas day harmonisation with the DWGM."

QGC similarly commented that "the proposed pipeline access reforms" will assist further in developing financial risk management products. It therefore suggested that:[188]

> "there is basis for combining this matter [the gas day harmonisation rule change process] as part of any changes proposed as an outcome from the Wholesale Markets Workstream as part of the Stage Two Review recommendations"

In addition, the MEU stated that if a move to provide for trading pipeline capacity is to occur "it is essential" that this be made in conjunction with harmonising the gas day.[189]

Certain stakeholders suggested that the change over date to a new gas day be specified at an off-peak time when there is a seasonal resourcing lull. For the Eastern Gas Pipeline

181 Submissions on the consultation paper: Allgas, p. 2; APA, p. 5; EnergyAustralia, p. 2., AGNL, p. 2.

182 AEMO, submission on the consultation paper, p. 5.

183 APPEA, submission on the consultation paper, p. 1.

184 APGA, submission on the consultation paper, p. 1.

185 Engie, submission on the consultation paper, p. 1.

186 EnergyAustralia, submission on the consultation paper, p. 1.

187 APLNG, supplementary submission on the consultation paper, p. 2.

188 QGC, submission on the consultation paper, p. 3.

189 MEU, submission on the consultation paper, p. 1.

and Jemena Gas Network, this would be in summer.[190] For similar reasons, APA suggested April as an optimum period to introduce the use of a new gas day.[191]

6.3 Draft determination

The Commission stated in the draft rule determination that there should be no less than twelve months between the date of the final rule being made and the commencement of the new gas day start time. The Commission considered a twelve month period should provide sufficient time for:

- AEMO to make changes to its procedures and the exchange agreement
- businesses to amend GTAs, GSAs and other associated contracts, implement changes to metering infrastructure and make amendments to business practices and systems.

The draft rule did not include any transitional rules relating to:

- the transitional day
- the date by which changes should be made to AEMO's procedures and the exchange agreement
- any specific entity having responsibilities to coordinate the transition.

The Commission determined 1 April 2021 as the date for the commencement of changes to the gas day in the draft rule so that the harmonisation of the gas day would be coordinated with other gas market reforms.

6.4 Stakeholder views - second round consultation

6.4.1 The transition period

Concerns regarding how the transition from the existing gas day start time to the new gas day start time would be managed were raised again by several stakeholders in response to the draft rule determination. AGL's concern was primarily that "market participants be given sufficient time to participate in, and respond to, consultation by AEMO on procedure changes and amendments to STTM rules that will come about as a result of harmonisation".[192]

AGN, Jemena and Stanwell expressed concerns relating to coordinating adjustments to meters and systems.[193] Given that limited resources can be deployed, these adjustments will necessarily take a number of weeks to complete and these stakeholders considered that the transition would require coordination. Accordingly, the Commissions's final rule determination and AEMO's procedures should address the transition and cutover process. Jemena suggested:[194]

190 Jemena, submission on the consultation paper, p. 3.

191 APA, submission on the consultation paper, p. 5.

192 AGL, submission on the draft rule determination, pp. 1-2.

193 Submission on the draft rule determination: AGNL, p. 1; Jemena, p. 2; Stanwell, p. 2.

194 Jemena, submission on the draft rule determination, p. 2.

> "To address this the AEMC should include guidance in any final determination to AEMO to include the necessary level of flexibility within the Retail Market Procedures and STTM Procedures (in terms of procedures, transitional arrangements, dispensations and compliance requirements) to support an implementation where cutover cannot occur on a single day. AEMO should undertake an assessment of appropriate transition in consultation with market participants. This should take place to ensure the full impacts on resourcing and change requirements are clearly understood and include any necessary systems testing."

Similarly, AGNL submitted:[195]

> "It is likely that manual adjustments to some interval meter data will be necessary during an interim period over which meters are reprogrammed. Some additional cost will be incurred whilst these manual adjustments are required, until all sites have been reprogrammed. AGNL recommends that AEMO co-ordinates a planned cutover process with all industry participants. This will need to be explored in detail during the consultation process."

6.4.2 Maximising the benefits of the rule

Engie commented that it was disappointed with the extended period of time before the draft rule, if made, would commence but accepted this as "a cautious approach" given the AEMC's view that the cost of implementing a harmonised gas day would outweigh the benefits if introduced earlier.[196] It noted that introducing a harmonised gas day with broader east coast gas review changes "will coordinate the necessary gas market changes from the east coast review with the changes that are required for gas day harmonisation."[197]

APA also supported the draft rule commencement date and the approach of aligning the implementation of the new gas day start time with other market reforms including standardisation of contractual terms. This timeframe, APA considered, "may allow for more substantive legislative obligations to be developed and therefore improve the chances of effective implementation."[198]

Two stakeholders, APA and Shell, commented that the deferring commencement of the changes to the gas day would not materially diminish the costs of implementation. Shell considered that while the timeframe for commencing the rule would improve impacted businesses' ability to plan and budget, the costs would remain "unavoidable".[199] APA similarly submitted that the extended transition period "will likely have little impact of the real costs of implementation being the changes to physical metering, system

195 AGNL, submission on the draft rule determination, p. 1.

196 Engie, submission on the draft rule determination, p. 1.

197 ibid.

198 APA, submission on the draft rule determination, p. 1.

199 Shell, submission on draft rule determination, p. 1.

changes and contract changes which will be largely the same regardless of when the change occurs."[200]

Jemena commented that it appreciated the Commission taking account of consultation feedback and selecting an implementation date in the month of April. Jemena stated that an April implementation date would avoid Jemena's winter peaks and will allow regulated businesses to seek efficient costs as part of their next regulatory determinations.[201]

6.5 Commission analysis

6.5.1 The transition period

Implementation of a new gas day in the facilitated markets will require a transitional period prior to the date of commencement. There are a number of actions and changes that must be put in place before the change from one day to another can occur. As noted by the COAG Energy Council and stakeholders, the implementation of a new gas day may require:

- certain GTAs, GSAs and other associated contracts to have been reviewed and amended to reflect the new gas day start time
- the establishment and execution of a business program to implement changes to metering infrastructure on pipelines and other facilities
- the amendment of AEMO procedures and processes
- a change to the GSH exchange agreement
- the amendment of business practices and procedures for the affected stakeholders.

While all of these are important parts of the preparation to move to a new gas day, the information provided to the Commission indicates that it is the changes required to the metering infrastructure of a number of stakeholders that is likely to take the most time to complete. The time required by the various businesses depends on the extent and nature of remote controls available to the meters, the number of meters and the location and ease of access. This suggests that there should be no less than twelve months between the date of the final rule being made and the commencement of the new gas day start time. A twelve month period should provide sufficient time for all effected stakeholders to plan and execute the necessary changes for their business. It should also provide sufficient time for AEMO to carry out the required consultation processes to amend the relevant procedures and the exchange agreement.

The Commission does not consider it is necessary to include transitional rules relating to the transitional day[202] or specifying the date by which changes to AEMO procedures

200 APA, submission on the draft rule determination, p. 1.

201 Jemena, submission on the draft determination, pp. 2-3.

202 The pricing, scheduling and balancing period in the STTM will remain 24 hours except for the transitional day, which will be only 22 hours (in Queensland) and 23.5 hours (in NSW and SA). To comply with the STTM rules on the transitional day (and for the STTM to operate as intended on that day) those subject to the STTM rules will need to implement pro-rating strategies with respect

and the exchange agreement must be made. Some stakeholders' expressed concerns relating to detailed implementation issues that may arise during the period of time that participants are making changes to meters, for example. However, the final rule necessitates that AEMO make changes to procedures and the exchange agreement where this is necessary to be consistent with the changes to the NGR. The Commission considers that any further prescription that is required would be best managed through AEMO's consultation processes.

Given the period of time provided for implementation the Commission does not consider it necessary to allocate this time between AEMO and industry through placing an obligation on AEMO to complete changes to the procedures and the exchange agreement by a specified date. The final rule provides sufficient time for AEMO to make changes to its procedures and the exchange agreement within a timeframe that also allows participants are to make necessary changes to systems and processes arising from these procedure changes prior to gas day harmonisation commencing. It is also in participants' powers to initiate a change to procedures or the exchange agreement if they consider this to be necessary.

While some stakeholders suggested a market institution such as the AEMC or AEMO would be needed to manage the transition process to a new gas day start time,[203] the Commission considers that this would be unnecessary. The NGR already provides AEMO sufficient powers to manage changes to the relevant procedures and the exchange agreement through consultation processes with market participants.

AEMO may additionally coordinate a market readiness program on behalf of participants if it and those participants consider this a useful approach. Such a coordination role could be similar to the strategy AEMO is currently using in the implementation of a number of electricity reforms which make up the Power of Choice reform package.[204]

Such a program may set out a plan for managing, coordinating, informing, monitoring and reporting on AEMO and participants' operational preparedness. This could focus on the revised business systems and processes needed for a transition to the new gas day start time, including new procedural arrangements. However, it should be noted that under such a market readiness program approach market participants would still be responsible for making decisions on how best to transition their businesses to the new gas day start time. The Commission considers this appropriate and desirable as each business is best placed to make these decisions.

6.5.2 Maximising the benefits of the rule

Many stakeholders have identified a link between harmonising the gas day in the facilitated markets and the broader gas market reforms that have been the subject of the AEMC's east coast gas review. Specifically, the creation of an integrated east coast

to trading rights and quantities submitted to the market (and if necessary, bids) to reflect the short day. The Commission considers any necessary arrangements supporting the transition between the two different gas days are best managed in procedures given their technical and operational nature.

203 Submissions on the consultation paper: Allgas, p. 2; APA, p. 5; EnergyAustralia, p. 2., AGNL, p. 2.

204 See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Power-of-Choice/Readiness-Work-Stream, viewed 30 January 2017.

market that includes exchange-based trading in a wholesale market and also provides participants with the ability to make short-term pipeline capacity trades requires a number of features to be successful. One of these features is a common gas day across the east coast gas market.

As set out in Chapter 3 of this final rule determination, the Commission has considered the potential benefits of the proposed rule. This assessment has included consideration of the risks to achieving those benefits that have been identified by a number of stakeholders. It has also considered the potential costs that may be incurred by stakeholders that would be immediately impacted by the implementation of the proposed rule as well as those other stakeholders who may also adopt a new gas day.

Some stakeholders consider that they may benefit from the introduction of a common gas day across the facilitated markets in the near future. The benefit anticipated by these stakeholders is that a harmonised gas day would support the industry led use of trading in gas and pipeline capacity that is emerging in parts of the east coast gas market. The Commission's assessment is that a harmonised gas day would be consistent with these market developments.

This conclusion impacts on the question of: when should the changes to the gas day under the final rule commence. A commencement date set in the near future, allowing for a transitional period of 12 months as discussed above, may provide some benefit to the already emerging trading activities in the east coast gas market. However, it appears unlikely that this benefit would outweigh the implementation costs that would incurred by market participants.

Alternatively, a commencement date for a rule could be set at a date that relates to the market reforms recommended by the AEMC in the east coast review. The GMRG has commenced work on transportation (pipeline and hub services) capacity trading related reforms and plans to provide its final recommendations to the COAG Energy Council by December 2018.[205] As set out in Chapter 3, the GMRG will be making recommendations on any amendments that need to be made to the NGL to give the AEMC, AEMO or the AER additional powers to regulate new capacity trading arrangements; and any other amendments need to be made to the NGL, NGR or subordinate instruments to give effect to the reforms.

In establishing the GMRG, the COAG Energy Council also set out an indicative implementation schedule. This schedule proposes that development work on the capacity trading reforms, including amendments to the NGL, NGR and subordinate instruments, will be completed by mid-2021.[206]

A discussed in the draft rule determination, a benefit of commencing a rule at a date further into the future, such as in 2021, is that it will provide stakeholders with the ability to make use of existing business practices in changing to a new gas day start time. However, some stakeholders have stated that such an approach may not reduce implementation costs significantly. Some costs, such as making physical changes to meters, will be unavoidable.

205 The Chair of the GMRG, Dr Michael Vertigan, confirmed this by letter on 20 January 2017.

206 COAG Energy Council, Gas market reform package, bulletin two, 19 August 2016, p. 2; p. 4.

Nevertheless, the four years between the making of the final rule and its commencement provides an extended period to plan and budget for these changes. It also has the potential to mitigate some of the implementation costs and disruptions that could otherwise occur. For example, during the period it is likely that some parties will be negotiating new GTAs. These negotiations would be able to take into account that a new gas day is scheduled to commence on a particular future date. This may be more efficient than carrying out separate contract negotiations specifically to manage a new gas day at a later date. Similar opportunities may also arise in connection to revised access arrangements.

The Commission acknowledges that the time of the year in which the change to the gas day takes effect is also important for stakeholders as it will impact on their ability to resource and manage the change successfully. The load patterns of the gas markets in New South Wales and South Australia confirm the views of APA and Jemena that April is likely to be a suitable period to implement a change to the gas day for the facilitated markets.

However, the Commission considers that greater benefits that exceed costs would emerge if harmonisation of the gas day used in the facilitated markets was coordinated with the introduction of the anticipated exchange-based wholesale market trading arrangements and the short-term pipeline capacity trading framework. The Commission acknowledges that certain market participants would incur costs from the introduction of a new gas day start time. Other market and industry participants may elect to undertake the cost of making such a change if their assessment was that it would be appropriate for their business and that the benefits exceeded the costs. This is more likely when the other market reforms are implemented. This is because a harmonised gas day supports these new integrated market arrangements as it makes the arrangements more workable. As noted by some stakeholders, a common gas day is one element required to successfully implement the new market arrangements.

This conclusion impacts on the question of: when should the changes to the gas day under the final rule commence. A commencement date set in the near future, allowing for a transitional period of twelve months as discussed above, may provide some benefit to the already emerging trading activities in the east coast gas market. However, it appears unlikely that this benefit would outweigh the implementation costs that would incurred by market participants.

Alternatively, a commencement date for a rule could be set at a date that relates to the market reforms recommended by the AEMC in the east coast review and which are being progressed by the GMRG. In establishing the GMRG, the COAG Energy Council also set out an indicative implementation schedule. This schedule proposes that development work on the capacity trading reforms, including amendments to the NGL, NGR and subordinate instruments, will be completed by mid-2021.[207]

A benefit of commencing a rule at a date further into the future, such as in 2021, is that it will provide stakeholders to make use of existing business practices which may mitigate some of the implementation costs and disruptions that could otherwise occur. For example, during the period it is likely that some parties will be negotiating new GTAs.

207 ibid.

These negotiations would be able to take into account that a new gas day is scheduled to commence on a particular future date. This may be more efficient than carrying out separate contract negotiations specifically to manage a new gas day at a later date. Similar opportunities may also arise in connection to revised access arrangements.

While some costs, such as making physical changes to metering, will be unavoidable, the timeframe for implementation under the final rule provides an extended period to plan and budget for these changes.

6.5.3 Conclusion

The information provided in the August 2016 COAG Energy Council bulletin remains the best indication of when the key market reforms, and consequently a harmonised gas day, can commence. The Commission expects that the net benefits of harmonising the gas day start time will emerge when these reforms are implemented. On this basis, the Commission has decided to make 1 April 2021 the date for the commencement of changes to the gas day under the final rule.

Abbreviations

ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
COAG	Council of Australian Governments
Commission	See AEMC
DTS	Declared Transmission System
DWGM	declared wholesale gas market
exchange agreement	GSH exchange agreement
facilitated market	DWGM, STTM, GSH are all facilitated markets
GMRG	Gas Market Reform Group
GSH	gas supply hub
GSA	gas supply agreement
GTA	gas transportation agreement
NGL	National Gas Law
NGO	national gas objective
NGR	National Gas Rules
STTM	short term trading market

A Legal requirements under the NGL

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

A.1 Final rule determination

In accordance with ss. 311 and 313 of the NGL, the Commission has made this final rule determination and final rule in relation to the rule proposed by the COAG Energy Council.

The Commission's reasons for making this final rule determination are set out in section 2.4 of this document.

A copy of the final rule is attached to and published with this final rule determination. Its key features are described in section 2.3.

A.2 Power to make a rule

The Commission is satisfied that the final rule, which is a more preferable rule, falls within the subject matter about which the Commission may make rules.

The final rule falls within s. 74 of the NGL as it relates to:

- the operation of a short term trading market of an adoptive jurisdiction and a gas trading exchange
- the activities of registered participants, users, end users and other persons in a regulated gas market.

A.3 Power to make a more preferable rule

Under s. 296 of the NGL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issues raised in the rule change request, the more preferable rule will, or is likely to, better contribute to the achievement of the NGO.

As discussed in Chapter 2, the Commission has determined to make a final rule that is a more preferable rule. Its reasons for this decision are set out in sections 2.3, 3.2 and 5.3 of this final rule determination.

A.4 Commissions considerations

In assessing the rule change request, the Commission has considered:

- the Commission's powers under the NGL to make the rule
- the rule change request
- stakeholder submission and other information received during the first and second round of consultation[208]

[208] All stakeholder submissions have been referenced in the relevant chapters of this final rule determination.

- the Commission's analysis as to the ways in which the final rule will, or is likely to, contribute to the NGO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles.[209]

A.5 Other legal requirements

A.5.1 Civil penalty and conduct provisions

The Commission’s final rule does not amend or omit any rules of the NGR that are currently classified as civil penalty or conduct provisions under the NGL or the National Gas (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any provisions of the final rule be classified as civil penalty or conduct provisions under the NGL or the National Gas (South Australia) Regulations.

A.5.2 Compatibility with AEMO's declared system functions

Under s. 295(4) of the NGL, the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if it satisfied that the rule is compatible with the proper performance of AEMO's declared system functions. The final rule is compatible with AEMO's declared system function because it does not affect the performance of those functions.[210]

209 Under s. 73 of the NGL, the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

210 AEMO's declared system functions are specified in s. 91BA of the NGL.