AEMC

REVIEW

Australian Energy Market Commission

CONSULTATION PAPER

REVIEW INTO EXTENDING THE REGULATORY FRAMEWORKS TO HYDROGEN AND RENEWABLE GASES

21 OCTOBER 2021

INQUIRIES

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ABOUT THE AEMC

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

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1 INTRODUCTION

In August 2021, Energy Ministers tasked the Australian Energy Market Commission (AEMC or Commission) with a review of the National Gas Rules (NGR) and National Energy Retail Rules (NERR) in order to develop initial rules that will extend the regulatory frameworks to low-level hydrogen-natural gas blends and other renewable gases. In addition, the AEMC is to also provide Energy Ministers with advice on any changes to the National Gas Law (NGL) and National Energy Retail Law (NERL) required to enable these rules.

This chapter introduces the review and outlines:

- the context of the review
- the purpose and focus of the review
- the review processes
- the structure of this consultation paper.

For ease of reference this consultation paper uses the following terms:

- "natural gas equivalents" to refer to low-level blends and renewable gases that are suitable for consumption in existing natural gas appliances
- "other gas products" to refer to other gases and blends that are not suitable for consumption in existing natural gas appliances
- "constituent gases" to refer to gases (other than natural gas) that are used to create a natural gas equivalent or other gas product but are not themselves authorised for supply to end users.

1.1 Context for this review

In December 2018, Energy Ministers agreed to work together to develop and implement a National Hydrogen Strategy to build hydrogen export markets and deliver domestic hydrogen projects. In 2019, the COAG Energy Council Hydrogen Working Group, led by Dr Alan Finkel AO, developed the strategy, which was endorsed by Energy Ministers on 22 November 2019.

The National Hydrogen Strategy sets out several government actions to support the development of a hydrogen industry, one of which is to use clean hydrogen in gas distribution pipelines. The strategy noted, however, that before widespread blending of hydrogen in gas distribution pipelines can occur further work on a range of technical, economic, regulatory and legal matters will be required. Action 3.12 of the National Hydrogen Strategy recommended that a review of a range of matters be undertaken in 2020, including, among others the application of the NGL to hydrogen. The recommended review was undertaken and advice from it was provided to Energy Ministers in mid-2021.

On 20 August 2021, Energy Ministers agreed that the national gas regulatory framework should be amended to bring biomethane, hydrogen blends and other renewable methane gas blends within its scope.[1] Energy Ministers also agreed that the amendments should initially focus on natural gas equivalents and be expedited so that:

- regulatory barriers do not restrict proposed investments in projects involving the supply of natural gas equivalents or the facilities and activities involved in their supply
- existing regulatory arrangements and protections continue to work as intended where these products are supplied.

Regulatory framework amendments addressing these concerns have been identified as a priority by Energy Ministers because a number of trials of natural gas equivalents are expected to commence in 2021 and 2022, and there is currently uncertainty surrounding whether provisions in the NGL, including the definition of natural gas, may present a barrier to these trials.

The AEMC's review is part of a suite of reviews that will be conducted concurrently with the purpose of enabling the NGL, NGR, NERL and NERR to be extended to the supply of natural gas equivalents. The other reviews are being carried out by:[2]

- Jurisdictional officials, who are responsible for identifying and developing the changes required to the NGL, NERL and regulations made under the NGL and NERL.
- AEMO, who is responsible for reviewing its procedures and other subordinate instruments for the facilitated and regulated retail gas markets and will also inform the AEMC of any changes it considers necessary to the NGR to enable these changes.

Concurrent to these reviews, the AEMC is also undertaking a rule change process to assess a request to incorporate distribution connected facilities into the Victorian declared wholesale gas market (DWGM).[3]

This rule change request was submitted to the AEMC on 8 September 2021 by the Victorian Minister for Energy, Environment and Climate Change. It seeks to amend Part 19 of the NGR to enable the participation of distribution connected production and storage facilities in the DWGM. As the intention of the request is not to limit distribution connected facilities to natural gas facilities, the request does have implications for enabling natural gas equivalents and constituent gases to be injected into gas distribution systems in Victoria. Accordingly, the rule change process complements the work of the broader national reviews.

1.2 Purpose and focus of this review

The purpose of the AEMC's review is to:

1. Identify potential issues in the NGR and NERR that could emerge if natural gas equivalents are permitted to be supplied through gas distribution pipelines.
2. Develop draft initial rules to address these issues through a consultative process.

1 "National gas regulatory framework" refers to the NGL, NGR, NERL, NERR and subordinate instruments made under these laws and rules.

2 Energy Ministers, Extending the national gas regulatory framework to hydrogen blends and renewable gases, information sheet, 23 September 2021 at https://energyministers.gov.au/publications/extending-national-gas-regulatory-framework-hydrogen-blends-and-renewable-gases

3 See AEMC website: https://www.aemc.gov.au/rule-changes/dwgm-distribution-connected-facilities

3. Inform jurisdictional officials of any changes to the NGL or NERL (or regulation made under the NGR or NERR) that it considers should be made to achieve the objective of the Energy Ministers.

In undertaking this review the Commission has assumed that the changes in the NGL and NERL will flow through to the NGR and NERR. That is, the existing provisions in the NGR and NERR will generally apply to both natural gas and natural gas equivalents unless bespoke requirements are identified. As a result, the review seeks to determine whether the NGR and NERR require any amendments to accommodate natural gas equivalents. This will be carried out through the application of the assessment framework set out in chapter 2.

1.2.1 Scope of this review

The AEMC review will focus on the changes required to the NGR and NERR in order to address issues that could emerge if the NGL and NERL are extended to natural gas equivalents and their constituent gases. In doing so, it will also identify those changes that need to be made for the initial rules and whether any amendments to the NGR or NERR could be deferred. This prioritisation advice will assist the Energy Ministers in meeting the expedited time frame that has been set for these reforms.

Those parts of the NGR and NERR that the Commission considers are within the scope of its review are summarised below and shown in Figure A.2 and Table A.1 in Appendix A.

- economic regulation of pipelines — issues on the operation of economic regulation, ring-fencing arrangements and the rights of natural gas equivalents and constituent gases suppliers to connect to pipelines
- market transparency mechanisms — the application of the reporting obligations for the Bulletin Board, Gas Statement of Opportunities and Victorian Gas Planning Report
- facilitated gas markets (the Victorian declared wholesale gas market and the short term trading market) — potential changes to registration categories, managing settlement and allocation and trading natural gas equivalents and constituent gases through the facilitated markets
- regulated retail markets — potential changes to registration categories, impacts on settlement, metering and billing
- consumer protections — managing issues the sale and supply of a natural gas equivalents that may arise between retailers, distributors and customers such as pricing, notification requirements and billing data
- regulatory sandbox framework — how this new framework can be used for trial projects using natural gas equivalents.

As noted in the officials' consultation paper, the amendments made to the NGL and NERL are expected to be made in a way that, where relevant, flows through to the rules, regulations, procedures and other subordinate instruments. In the case of natural gas equivalents, this is likely to involve treating these products as natural gas for the purposes of the laws, rules and procedures. This will have the effect of minimising the changes that need to be made to the NGR and NERR.

1.2.2 Out of scope of this review

There are a number of areas that are out of scope of this review. This is because they are either outside the AEMC's responsibilities or the terms of reference provided for this review, or the Commission's preliminary assessment indicates that an issue is unlikely to be a priority for the initial rules package.

The following issues are outside the AEMC’s responsibilities, or are not captured by the scope of the terms of reference:

- jurisdictional arrangements, including licensing — amendments that will need to be made to jurisdictional legislation and regulations to accommodate natural gas equivalents are matters for the respective jurisdictional governments and not an AEMC responsibility
- other gas products that are not suitable for consumption as natural gas are not included in this review as the terms of reference specify that the focus is on accommodating natural gas equivalents in the NGR and NERR[4]
- impacts, including the operation of facilities such as electrolysers, on the National Electricity Law or National Electricity Rules are not specified in the terms of reference as within scope of this review.

It should be noted that the official’s consultation paper proposes a potential approach to extending the national regulatory framework to other gas products through changes to the NGL, and where relevant, the NERL. If implemented, this approach would allow the rules and procedures to be amended in the future to accommodate other gas products once jurisdictions authorise their supply and bring the supply of other gas products within the scope of the national regulatory framework. However, for this current review, the AEMC has not been tasked with considering the NGR and NERR changes that would be required if the national framework was extended to other gas products.

The Commission has formed the preliminary view on some parts of the NGR and NERR are: not within the scope of this review under the terms of reference; are not expected to be impacted by the proposed changes; or are unlikely to be a priority for this review. The identified out of scope parts are shown in Figure A.2 and described in Table A.2 in Appendix A.

The Commission has also identified the issue of the treatment of the cost of producing constituent gases on the retail market. Its preliminary view is that this issue is not a priority for this review due to the initial expected low quantities of constituent gases as a proportion of natural gas equivalents supplied in distribution systems. However, it may be relevant for future work on market design as constituent gases increase proportionally as a share of the overall gas stream. This is noted in chapter 6 on Regulated retail markets.

4 Chapter 8 of this paper discusses the impact of extending the regulatory sandbox provisions to other gas products before other aspects of the NGR and NERR frameworks accommodate those products. The extension of the NGR and NERR to other gas products may be considered by the AEMC in the future.

> QUESTION 1: SCOPE OF THE REVIEW
> 1. Do you agree with the Commission's preliminary position on the scope of this review?
> 2. Are there additional areas in the NGR or NERR that should be excluded or included in the current review? If so, why?

1.3 Review process

1.3.1 AEMC review process

The key deliverables and dates for the AEMC's review are outlined in the table below.

Table 1.1: **AEMC's review — key milestones**

MILESTONE	DATE
Publication of this consultation paper	21 October 2021
Submissions to this consultation paper close	2 December 2021
Publication of draft report with draft rules for consultation	31 March 2022
Submissions to the draft report and rules close	12 May 2022
Publication of final report (with finalised policy positions) and draft initial rules for consultation	8 September 2022
Provide final initial draft rules to Energy Ministers for approval	by 14 November 2022

For more detail on the AEMC review process please see appendix A.

1.3.2 Lodging a submission and next steps

Written submissions on this consultation paper must be lodged with the Commission by COB Thursday 2 December 2021 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code EMO0042.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions which is available from the AEMC website. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to James Tyrrell on (02) 8296 7842 or james.tyrrell@aemc.gov.au.

2 ASSESSMENT FRAMEWORK

The terms of reference from Energy Ministers are made under the NGL and the NERL. Under the terms of reference the purpose of the review is for the AEMC to:[5]

> advise Energy Ministers on the initial rules required in the national gas and retail regulatory frameworks to accommodate low level hydrogen blends and renewable gases, and advise on any changes to the law required to enable these rules.

This chapter outlines the:

- decision-making framework the Commission must apply to determine whether the proposed rules contribute to the NGO and the NERO
- proposed assessment framework.

2.1 Achieving the NGO and NERO

In light of the purpose of this review, the Commission's advice to Energy Ministers will reflect its considerations of what amendments to the NGR and NERR should be made to achieve the Energy Ministers' objective but also be consistent with achieving the relevant energy objectives.

The Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national gas objective (NGO)[6] and the national energy retail objective (NERO).[7]

The NGO is:[8]

> 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, safety, reliability and security of supply of natural gas.

The NERO is:[9]

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

In relation to the NERO, the Commission must also, where relevant, satisfy itself that the rule is "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers" (the "consumer protections test").[10]

5 Energy Ministers, terms of reference, 24 August 2021, p. 3.
6 Section 291(1) of the NGL.
7 Section 236(1) of the NERL.
8 Section 23 of the NGL.
9 Section 13 of the NERL.
10 Section 236(2)(b) of the NERL.

Where the consumer protections test is relevant in the making of a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been met.[11] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made.

There may be some overlap in the application of the two tests. For example, a rule that provides a new protection for small customers may also, but will not necessarily, promote the NERO.

2.2 Proposed assessment framework

To determine whether the review's recommendations would be likely to promote the NGO and the NERO, the Commission will carry out its assessment against the framework outlined below. This framework may be refined during the process of the review.

The proposed assessment framework includes the following criteria:

- **Efficiency**: By expanding an existing market to cover new services and commodities that could not otherwise be priced or traded within the gas market, do the changes being considered encourage the delivery of a new service or commodity and thereby encourage:
    - Allocative efficiency — do the changes being considered enable market prices which facilitate the allocation of gas, including natural gas equivalents, to their highest valued uses.
    - Productive efficiency — do the changes being considered enable operational signals to facilitate dispatch of the least-cost mix of gas supply, including natural gas equivalents, to meet demand.
    - Dynamic efficiency — do the changes being considered minimise barriers to entry and promote efficient investment in the gas market, including investment in production and storage facilities as well as investment in the distribution and transmission systems to meet gas demand over time.
- **Innovation:** whether the proposed changes facilitate innovation in the development of gas production, storage, transmission and distribution facilities and in the provision of gas services to end users.
- **Implementation considerations**: Are the proposed changes targeted, fit for purpose and proportionate to the issues they are intended to address. Do the proposed changes provide the stability and transparency in regulatory arrangements to enable consumers, market participants and investors to make efficient decisions. Consideration will be given to existing and prospective production facilities and the impact of any changes recommended on their actual and planned operations. Consideration of implementation factors will include considering whether and how future production facilities can be incorporated into the existing market design without introducing excessive complexity.

11 That is, the legal tests set out in s. 236(1) and (2)(b) of the NERL.

- **Decarbonisation**: Whether market arrangements will enable the decarbonisation of the energy market.
- **Quality, safety, reliability and security of supply**: Whether the changes provide a clear allocation of roles and responsibilities in relation to the quality and safety of supply of natural gas equivalents to consumers.
- **Consumer protections**: Whether changes being considered under the review are compatible with the development and application of consumer protections for small customers, including, but not limited to protections relating to hardship customers. Whether additional protections are required for customers being supplied with natural gas equivalents.

QUESTION 2: ASSESSMENT FRAMEWORK

1. Do you agree with the Commission's proposed assessment framework for this review?
2. Are there any criteria the Commission should or should not consider as a part of its assessment framework?

3 ECONOMIC REGULATION OF PIPELINES

The NGL and NGR set out the economic regulatory framework that applies to transmission and distribution pipelines involved in the transportation of natural gas in eastern Australia, the Northern Territory and Western Australia. The objective of the economic regulatory of pipelines is to:

- facilitate third party access to transmission and distribution pipelines
- constrain the exercise of market power by transmission and distribution pipeline service providers.

This chapter sets out:

- an overview of the economic regulatory framework
- issues for consultation, which include:
    - supplier access to pipelines
    - ring-fencing arrangements
    - rules for scheme pipelines
    - rules for non-scheme pipelines
    - pipeline information on the type of gas.

3.1 Overview of the economic regulatory framework

The economic regulatory framework that applies to natural gas transmission and distribution pipelines will be amended to reflect the recent decision by Energy Ministers to implement a simpler regulatory framework that will pose a more effective constraint on service providers' market power, facilitate better access to pipelines and provide greater support for commercial negotiations.[12] The amendments to the NGL and NGR required to give effect to this decision have recently been released for consultation and are expected to be implemented in late 2022.[13] Given Energy Ministers have already agreed to amend the framework, this consultation paper assumes the amendments to the framework will be made. Under the agreed reforms, all transmission and distribution pipelines will be required to provide third party access if requested to do so and will be classified as either:

- Scheme pipelines: these pipelines will be subject to a stronger regulatory-oriented form of regulation, based on the existing full regulation.
- Non-scheme pipelines: these pipelines will be subject to a lighter commercially-oriented form of regulation.

The table below provides further detail on what regulatory arrangements will apply to scheme and non-scheme pipelines under the new agreed framework. Appendix B.1 provides further detail on the framework and Box 1 provides an overview of the objective and provisions covered by the framework.

12 Energy Ministers, *Options to improve gas pipeline regulation, regulation impact statement for decision*, 3 May 2021 at https://energyministers.gov.au/publications/energy-ministers-release-gas-pipeline-decision-regulation-impact-statement

13 See https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

Table 3.1: **Scheme and non-scheme pipelines under the new agreed regulatory framework**

KEY ELEMENTS OF THE NEW REGULATORY FRAMEWORK		PIPELINE TYPE	
		SCHEME	NON SCHEME
Forms of regulation		Negotiate-arbitrate with approved reference tariffs	Negotiate-arbitrate
Requirement to submit an access arrangement to the regulator		Yes	No
Safeguard to constrain exercises of market power	Prohibition on preventing or hindering access	Both	
	Prohibition on bundling services	Both	
	Required to comply with pipeline interconnection principles	Both	
	Prohibition on increasing charges to subsidise new capacity	Both	
	Ring fencing requirements and associate contract provisions	Both — Exemption from requirements available if pipeline is not a third party access pipeline	
Requirement to publish a range of information to facilitate access		Both — Exemption from all requirements available if pipeline is not a third party access pipeline. Exemption from financial disclosures available to single shipper and small pipelines.	
Duty to negotiate in good faith & comply with negotiation framework in NGR		Both	
Access dispute provisions		Regulatory oriented dispute mechanism	Commercially oriented dispute mechanism

Source: AEMC.

BOX 1: POLICY OBJECTIVE, PROVISIONS, AND JURISDICTIONAL APPLICATION

Policy objective

The objective of the economic regulatory framework is to:

- facilitate third party access to transmission and distribution pipelines
- constrain the exercise of market power by transmission and distribution pipeline service providers.

Relevant provisions

Based on the consultation version of the draft Bill and amending rule for pipeline regulation reforms.[1]

NGL: Chapters 1-5.

NGR: Parts 4-12, 13 and 15.

Jurisdictional application

The economic regulatory provisions in the NGL and NGR apply in all jurisdictions.

Note: 1) See senior officials, *Improving gas pipeline regulation, proposed legal package to give effect to the decision regulation impact statement*, consultation paper, September 2021 at https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation.

3.2 Issues for consultation

If the NGL is amended to extend its application in the manner described in the officials' consultation paper, then the economic regulatory framework would apply to pipelines involved in the haulage of natural gas equivalents and constituent gases in the same way it does to pipelines that transport natural gas. Pipelines involved in the haulage of a natural gas equivalent or constituent gases would therefore be classified as either a scheme or non-scheme pipeline and subject to the same regulatory obligations as those set out in Table 3.1 above.

Based on the consultation versions of the draft Bill and amending rule that senior officials have recently released for the pipeline regulation reforms,[14] it would appear that most elements of the new regulatory framework could be applied without amendment to pipelines involved in the haulage of natural gas equivalents or constituent gases. However, some issues have been identified that may need to be addressed in the NGR to effectively accommodate the supply of natural gas equivalents.

These issues relate to:

- the rights that suppliers of natural gas equivalents and constituent gases will have to connect to scheme and non scheme pipelines

14 Senior officials, *Improving gas pipeline regulation, proposed legal package to give effect to the decision regulation impact statement*, consultation paper, September 2021 at https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

- the ring fencing arrangements that will apply to scheme and non-scheme pipelines
- the amendments that may need to be made to the rules applying to scheme and non-scheme pipelines to accommodate pipelines transitioning from transporting natural gas to natural gas equivalents
- whether the service providers should be required to publish information on the type of gas their pipelines are licensed to carry and any plans they have to transition to another gas.

3.2.1 Access to pipelines by suppliers of natural gas equivalents and constituent gases

If a pipeline (or part of a pipeline) transitions to the supply of a natural gas equivalent blend product and it is only licensed to transport a specified blend (for example, a 10 per cent hydrogen blend), then it will be important to ensure from both a pipeline safety and customer end-use perspective that the blending limit is not exceeded.

This may result in constraints having to be imposed on where suppliers of the natural gas equivalent or constituent gases can connect to the pipeline, particularly if there are users in parts of the pipeline that are unable to use a blended product (or can only use very low level blends).[15] It may also result in the supply of the blended product having to be curtailed if the blending limit is likely to be breached.[16]

Connections

The draft amending rule for the new regulatory framework includes a number of interconnection principles that scheme and non-scheme pipelines will be required to comply with.[17] Among other things, these principles give a person the right to connect a facility to a pipeline where it is:[18]

- technically feasible and consistent with the safe and reliable operation of the pipeline
- the person is prepared to fund the cost associated with making the interconnection.

The reference in this rule to a connection being "technically feasible and consistent with the safe and reliable operation of the pipeline" would appear to provide service providers sufficient scope to reject a proposal to connect to a part of the pipeline if it is likely to result in the blending limit being breached.

The Commission's preliminary view is that this part of the NGR is unlikely to need amending and may be fit for purpose for the introduction of natural gas equivalents. However, there may be issues to consider on whether:

- there would be value in requiring service providers to publish information on where such connections would be technically feasible to facilitate access by these facilities, or

15 For example, users of natural gas as a feedstock and suppliers of compressed natural gas may not be able to tolerate the same blending level as other users of that pipeline.

16 For example, if the supply of natural gas into a distribution pipeline was adversely affected on a day, then it may be necessary to curtail the supply of the blended product to ensure the blending limit is not breached.

17 See Part 6 in Attachment 3 - Draft amendments to the NGR and Transitional Provisions, https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

18 ibid, draft amending rule 37.

- connections of this form are likely to be so infrequent that questions of where it is technically feasible to connect should be left to bilateral discussions between the service provider and proponents.

Curtailment

The current and the draft amending economic regulation provisions in the NGR do not deal with curtailment. To date, curtailment has instead been dealt with through contracts between the service provider and shippers. These contracts will, for example, typically set out the rights that a service provider has to curtail supply if off-specification gas is supplied into the pipeline, or if there is some other event that requires curtailment.

While curtailment of suppliers of natural gas equivalents or constituent gases could also be dealt with contractually, an alternative is to include specific rules in the NGR to deal with curtailment.

One potential reason that rules may be required is if service providers (or their associates) are also suppliers of a natural gas equivalent or constituent gases. If these facilities are not appropriately ring-fenced, it is possible that service providers may favour their own facilities by curtailing other suppliers first.

QUESTION 3: SUPPLIER ACCESS TO PIPELINES

1. Do you think that any additional guidance is required in the NGR to deal with connections by suppliers of natural gas equivalents or constituent gases, or are the new draft interconnection rules sufficient? If you think additional guidance is required, please set out what guidance you think is required.
2. Do you think service providers should be required to publish information on where connections by suppliers of natural gas equivalents or constituent gases would be technically feasible, or should this just be left to negotiations?
3. Do you think that any specific rules are required in the NGR to deal with the risk that service providers may favour their own natural gas equivalents or constituent gas facilities by curtailing other facilities ahead of their own, or do you think this should be dealt with through ring-fencing arrangements?

3.2.2 Ring-fencing arrangements

Under the officials' proposed amendments to the NGL, the ring-fencing provisions in the NGL would be extended to the facilities and activities involved in the production, purchase and sale of natural gas equivalents and their constituent gases.[19] Service providers of scheme and non-scheme pipelines would therefore be prohibited from producing, purchasing or selling natural gas equivalents or constituent gases (except to the extent necessary for the safe and

19 Jurisdictional officials, *Extending the national gas regulatory framework to hydrogen blends & renewable gases*, consultation paper, 21 October 2021, p. x.

reliable operation of the pipeline, or to provide balancing services) unless they obtain an exemption under the NGR.[20]

The NGR currently provides for an exemption from this prohibition to be obtained if the regulator is satisfied that each of the following criteria are met: [21]

- either the pipeline is not a significant part of the pipeline system for any participating jurisdiction, or the service provider does not have a significant interest in the pipeline and does not actively participate in pipeline management or operation
- the cost of compliance would outweigh the public benefit resulting from compliance
- the service provider has, by arrangement with the regulator, established internal controls within the business that substantially replicate the effect achieved if a related business were divested to a separate entity and dealings subject to the controls applicable to associate contracts.

While these exemption criteria appear fit for purpose, the criteria could be amended to allow service providers to produce, purchase or sell natural gas equivalents or constituent gases if a trial is being undertaken, potentially under certain limits on the volume they can produce, purchase or sell.

QUESTION 4: RING-FENCING ARRANGEMENTS

1. Do you think the ring-fencing exemptions in the NGR should be amended to accommodate trials by service providers? Why?
2. If so, do you think there should be any limit on the volume service providers should be able to producer, purchase or sell (e.g. up to the unaccounted for gas level)?
3. Do you think any other changes need to be made to the ring-fencing provisions in the NGL or NGR to accommodate natural gas equivalents or constituent gases?

3.2.3 Rules applying to scheme pipelines

The Commission's initial view is that the draft amending rules that will apply to scheme pipelines under the new regulatory framework, could be readily applied to pipelines transporting natural gas equivalents or constituent gases. However, it is possible that, some amendments may be required to deal with pipelines that are proposing to transition from transporting natural gas to natural gas equivalents.

Amendments may, for example, be required in Part 9 of the NGR to provide additional guidance to the regulator on how to assess service provider proposals for an access arrangement to transition to a natural gas equivalent if the transition is not mandated by a jurisdiction. If a jurisdiction mandates that a pipeline transition to a natural gas equivalent,

20 This prohibition only applies to service providers and not to associates. Relationships between service providers and their associates are regulated through the associate contract provisions in the NGL.

21 Rule 31 of the NGR; draft amending rule 34 in Attachment 3 - Draft amendments to the NGR and Transitional Provisions, https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

this would be treated as a regulatory obligation[22] for the purposes of the NGL and NGR and the regulator would have limited scope to reject proposed expenditure for the transition.[23] However, if the transition is not mandated, the regulator would need to assess the proposed expenditure having regard to the expenditure criteria in the NGR.

A service provider that wanted to transition to transporting a natural gas equivalent but was not required to do so by a jurisdiction, would need to show that the proposed expenditure is "such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services".[24] It would also need to show that any proposed capital expenditure is justifiable because either:[25]

- the overall economic value is positive
- the present value of incremental revenue exceeds the present value of the expenditure.

While these expenditure criteria appear fit for purpose, Part 9 of the NGR could be amended to provide the regulator with additional guidance on how to assess proposals that include a transition to natural gas equivalents.

In addition, greater guidance in the NGR could be required in relation to how grants from governments and agencies, such as the Australian Renewable Energy Agency, should be treated for regulatory purposes. The Commission would expect such grants to be treated similarly to capital contributions by users under rule 82 of the NGR. However, there is no specific rule (in the current or draft amending rules) to this effect.

QUESTION 5: RULES FOR SCHEME PIPELINES

1. Do you think Part 9 of the NGR should be amended to provide the regulator with additional guidance on how to assess service provider proposals to transition to natural gas equivalents in those cases where a jurisdiction does not mandate the transition? If so, please explain what changes you think need to be made and why.
2. Do you think Part 9 of the NGR should be amended to clarify how government grants or funding are to be treated for regulatory purposes?

22 The revenue and pricing principles in s. 24 of the NGL, which the regulator must take into account when exercising discretion in approving an access arrangement, state that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in "complying with a regulatory obligation or requirement". The term "regulatory obligation" is then defined in s. 6 of the NGL as a pipeline safety duty, a pipeline reliability standard, a pipeline service standard, an obligation under the NGL/NGR, NERL/NERR or an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act that levies or imposes a tax or other levy, regulates the use of land, relates to the protection of the environment, or materially affects the provision of pipeline services to which an applicable access arrangement applies.

23 The regulator would still need to be satisfied that the proposed expenditure is "such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services' (rules 79 and 91 of the NGR). It would not, however, in the case of capital expenditure need to be satisfied that the overall economic value is positive or that the present value of incremental revenue exceeds the present value of the expenditure.

24 Rules 79 and 91 of the NGR.

25 Rule 79 of the NGR.

3. Do you think any of the other rules that will apply to scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?

3.2.4 Rules applying to non-scheme pipelines

As with scheme pipelines, the Commission's initial view is that the draft amending rules that will apply to non-scheme pipelines under the new framework are capable of being applied to pipelines transporting either natural gas equivalents or constituent gases. However, it is possible that some amendments to the NGR may be required to deal with pipelines that are either, required by a jurisdiction to transition to transporting natural gas equivalents, or are otherwise proposing to make the transition.

Unlike scheme pipelines, the regulator has no role in approving proposed expenditure or tariffs for non-scheme pipelines. These matters are instead negotiated between service providers and shippers and if a dispute arises, then an arbitrator can be called upon to resolve the dispute.

Currently arbitrators are not required to take into account the regulatory obligations that non-scheme pipelines may be subject to when resolving disputes.[26] In the context of jurisdictions placing requirements on non-scheme pipelines, it could be relevant to amend the arbitration principles in Part 12 of the NGR to require arbitrators to take this into account in the same way a regulator is required to for scheme pipelines.[27]

If Part 9 of the NGR is to be amended to provide the regulator with greater guidance on how to assess proposals to transition to natural gas equivalents and how to treat government grants, then it could also be relevant to amend the arbitration principles in Part 12 of the NGR to provide the arbitrator with the same guidance regarding non-scheme pipelines.

QUESTION 6: RULES FOR NON-SCHEME PIPELINES

1. Do you think the arbitration principles applying to non-scheme pipelines should be amended to:
   a. require the arbitrator to take into account any regulatory obligation that a pipeline may be subject to?
   b. provide the arbitrator with greater guidance on how to assess proposals by a service provider to transition to transporting a natural gas equivalent where the transition is not mandated?
   c. clarify how government grants are to be treated?

26 Rule 79(2)(c) of the NGR; revenue and pricing principles in s. 24 of the NGL.

27 See draft amending rule 113Z in Attachment 3 - Draft amendments to the NGR and Transitional Provisions, https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

2. Do you think any of the other rules that will apply to non-scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?

3.2.5 Information on the type of gas a pipeline is transporting or proposing to transition to

Under the current regulatory framework, all pipelines are assumed to transport natural gas. This will not, however, be the case under the proposed reforms. As such, greater transparency may be required to ensure that users, retailers and the regulator have a good understanding of what the pipeline is licensed to transport and any plans a service provider has to transition to another gas.

This could be achieved by requiring service providers to publish:

- information on the type of gas the pipeline is licensed to transport
- information on the following if the service provider has firm plans to conduct a trial, or to transition the pipeline (or part of the pipeline) to a natural gas equivalent or other gas product:
  - the type of gas the service provider intends to trial or transition to
  - when the trial or transition is expected to occur
  - if the trial or transition will apply to the whole pipeline, or a part of the pipeline.

If service providers were required to publish this information, it could be included in their user access guides that are published on their websites.[28] In the case of scheme pipelines, this information could also be included in the access arrangement and access arrangement information. The information could also be reported on the AEMC's Pipeline Register so that interested parties can readily access the information for a number of pipelines.[29]

QUESTION 7: PIPELINE GAS TYPE INFORMATION

1. Do you think service providers should be required to publish information on:
   a. The type of gas they are licensed to transport in their user access guides and, in the case of scheme pipelines, the access arrangement and access arrangement information? Why?
   b. Any firm plans to conduct either a trial or to transition the pipeline (or part of the pipeline) to a natural gas equivalent or other gas product? Why?
2. Do you think this information should also be reported on the AEMC's Pipeline Register?

28 Under the draft amending rules, service providers of scheme and non-scheme pipelines will be required to publish a user access guide. Draft amending rule 105B in Attachment 3 - Draft amendments to the NGR and Transitional Provisions, https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

29 https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register

4 MARKET TRANSPARENCY MECHANISMS

The NGL and NGR currently provide for the following gas market transparency mechanisms:

- the Natural Gas Services Bulletin Board (Bulletin Board or BB), which is a website operated by AEMO that contains a range of market and system information for eastern Australia and the Northern Territory [30]
- the Gas Statement of Opportunities (GSOO), which is an annual report published by AEMO that assesses the adequacy (or otherwise) of supply in eastern Australia to meet forecast demand and the outlook for the industry over a 20-year outlook period[31]
- the Victorian Gas Planning Report (VGPR), which is a biennial report published by AEMO that provides a supply and demand and pipeline capacity adequacy assessment for the Victorian Declared Transmission System (DTS) over a five-year outlook period.[32]

This chapter sets out:

- an overview of the existing and new market transparency mechanisms
- issues for consultation, which include:
  - extending the transparency mechanisms to natural gas equivalents
  - extending the transparency mechanisms to constituent gases.

4.1 Overview of market transparency mechanisms

The Bulletin Board was implemented in mid-2008 to provide market participants and other interested parties with ready access to information on the capacity and utilisation of natural gas production, transportation and storage facilities. In the intervening period, the Bulletin Board's scope has been expanded to include a range of market and system based information for eastern Australia and the Northern Territory.

The GSOO was introduced at a similar time to the Bulletin Board and is intended to enable market participants and other interested parties to make informed decisions about investment in pipeline capacity and other aspects of the natural gas industry in eastern Australia.[33]

Like the GSOO, the VGPR is intended to facilitate informed and efficient investment in the DTS and to assist market participants and other persons make economically efficient investment decisions in other aspects of the natural gas market.

In March 2020, Energy Ministers agreed to a range of measures to improve transparency in the gas market, including through the imposition of new reporting obligations for compression and storage facility service providers and a new gas price reporting function for

30 https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb. The WA Bulletin Board is established under WA's Gas Services Information Act 2012 (WA) and Gas Services Information Regulations 2012, which are out of scope of this review.

31 https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo. The WA GSOO is established under WA's Gas Services Information Act 2012 (WA) and Gas Services Information Regulations 2012, which are out of scope of this review.

32 https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report

33 Section 91D of the NGL.

the AER. The amendments to the NGL and NGR required to give effect to this decision are being progressed through the South Australian Parliamentary process and are expected to be implemented in 2022.[34] For the purposes of this consultation paper, the Commission has assumed these amendments will be implemented. These amendments, which are expected to come into effect in 2022, provide for, among other things:

- information to be collected for the Bulletin Board and GSOO from any person who has possession or control of information in relation to the natural gas industry
- the specification of a range of additional information to be reported on the Bulletin Board and through the GSOO
- the extension of the GSOO to the Northern Territory and the inclusion of new powers to enable AEMO to make GSOO Procedures and to issue mandatory surveys
- the operators of storage and compression facilities to publish a range of information on their terms and conditions of access and the prices paid by users of their facilities[35]
- the AER to publish gas price information once the Australian Competition and Consumer Commission's (ACCC) Gas Inquiry ceases in 2025.[36]

Further detail on the five transparency mechanisms that will be included in the NGL and NGR once these amendments are made is provided in the box below and in appendix B.2.

BOX 2: POLICY OBJECTIVES, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objectives

Bulletin Board: The objective of the Bulletin Board is to make information relating to the natural gas industry available to market participants and other persons to facilitate:

1. trade in natural gas and natural gas services
2. informed and efficient decisions in relation to the provision and use of natural gas and natural gas services
3. negotiations for access to BB pipelines and other BB facilities providing third party access.[1]

GSOO: The objective of the GSOO is to make information available to assist market participants and other persons make informed investment decisions in the natural gas industry and to understand the adequacy of supply to meet forecast demand over a 20-year period.

VGPR: The objective of the VGPR is to facilitate planning and investment decisions in the DTS

34 Senior officials, *Measures to improve transparency in the gas market, proposed legal package to give effect to decision regulation impact statement*, consultation paper, 19 November 2020 at https://energyministers.gov.au/publications/consultation-draft-regulatory-amendments-increase-transparency-gas-market-0.

35 The changes to the NGL and NGR required to implement the storage and compression service provider reporting obligations are being consulted on as part of the gas pipeline draft legal package. See https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

36 On 25 July 2019, the ACCC's Gas Inquiry was extended until December 2025. ACCC, *Looming gas supply shortfall for east coast*, media release, 17 August 2021 at https://www.accc.gov.au/media-release/looming-supply-shortfall-for-east-coast-market.

and to make information available to assist market participants and other persons make economically efficient investment decisions in natural gas markets.

Compression and storage terms and prices: The objective of these provisions is to improve transparency and facilitate negotiations between the service providers of these facilities and prospective users.

AER new gas price reporting function: The objective of this function is to provide for greater transparency on gas prices and the factors that may affect these prices.

Relevant provisions (based on consultation version of draft Bill and rules)[2]

NGL: Chapter 2 (GSOO, VGPR and AER gas price reporting) and Chapter 7 (Bulletin Board).

NGR: Part 15D (GSOO), Part 17 (AER gas price reporting function), Part 18 (Bulletin Board), Part 18A (compression and storage terms and prices) and Part 19 (VGPR).

Jurisdictional application

Bulletin Board: These provisions in the NGL and NGR apply in the east coast and the Northern Territory.

GSOO: These provisions in the NGL and NGR currently apply in the east coast but will be extended to include the Northern Territory as part of the changes that are currently being implemented.

VGPR: The VGPR provisions in the NGL and NGR apply in Victoria.

AER gas price reporting function and compression and storage terms and prices: These new provisions will apply in the east coast and the Northern Territory.

Note: 1) Rule 145 of the NGR.
2) https://energyministers.gov.au/publications/measures-improve-transparency-gas-market-consultation and https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

4.2 Issues for consultation

Under the approach set out in the officials' consultation paper:

- the facilities and activities associated with the supply of natural gas equivalents will be treated in the same manner as their natural gas counterparts for the purposes of the transparency mechanisms
- the AEMC would be given the power to make rules to extend the transparency mechanisms to constituent gases and their related facilities and activities.

The implications of this approach for how the NGR may need to be amended are discussed below.

4.2.1 Extending the transparency mechanisms to natural gas equivalents

If the NGL is amended to extend its application in the manner described in the officials' consultation paper, then natural gas equivalents will be treated as if they are natural gas for the purposes of the NGR. The five transparency mechanisms outlined above will therefore automatically extend to the facilities and activities associated with the supply of natural gas equivalents.

In effect this would mean that the facilities and activities involved in the production, transportation, compression, storage and use of natural gas equivalents would be subject to the same reporting obligations as their natural gas counterparts under the relevant parts of the NGR. The table below sets out these requirements (see also appendix B.2).

Table 4.1: **Reporting obligations for natural gas equivalent facilities and activities**

NATURAL GAS EQUIVALENT FACILITY OR ACTIVITY	BULLETIN BOARD	GSOO	VGPR (VICTORIAN FACILITIES ONLY)	COMPRESSION & STORAGE TERMS AND PRICES	AER PRICE REPORTING
Production facility and blending facility	If nameplate rating >10 TJ/d, the facility would be a BB production facility and subject to the same obligations as natural gas BB production facilities	Facility captured by GSOO provisions and required to report equivalent information as natural gas production facilities	If a DWGM registered facility, the facility would be required to report equivalent information as natural gas production facilities	n.a	n.a
Transmission pipeline	If nameplate rating ≥10 TJ/d, facility would be a BB pipeline and subject to same obligations as natural gas BB transmission pipelines	Facility captured by GSOO and required to report equivalent information as natural gas transmission pipelines	If a DWGM registered facility, the facility would be required to report equivalent information as natural gas transmission pipelines	n.a	n.a
Storage facility	If nameplate rating ≥10 TJ/d, facility	Facility captured by GSOO and	If a DWGM registered facility, the	If the facility is classified as a BB storage	n.a

NATURAL GAS EQUIVALENT FACILITY OR ACTIVITY	BULLETIN BOARD	GSOO	VGPR (VICTORIAN FACILITIES ONLY)	COMPRESSION & STORAGE TERMS AND PRICES	AER PRICE REPORTING
	would be a BB storage facility and subject to same obligations as natural gas BB storage facilities	required to report equivalent information as natural gas storage facilities	facility would be required to report equivalent information as natural gas storage providers	facility, it will be subject to same obligations as natural gas storage facilities	
Compression facility	If nameplate rating ≥10 TJ/d, facility would be a BB compression facility and subject to same obligations as natural gas BB compression facilities	n.a	n.a	If the facility is classified as a BB compression facility, it will be subject to same obligations as natural gas compression facilities	n.a
Large user or market customer	If reporting threshold met, facility would become a BB large user and subject to same obligations as natural gas BB large users	Facility captured by GSOO and required to report equivalent information as natural gas large users	If DWGM registered, the market customers would be required to report equivalent information as natural gas market customers	n.a	n.a
Parties to gas supply	If reporting threshold	n.a	n.a	n.a	If identified in AER price

NATURAL GAS EQUIVALENT FACILITY OR ACTIVITY	BULLETIN BOARD	GSOO	VGPR (VICTORIAN FACILITIES ONLY)	COMPRESSION & STORAGE TERMS AND PRICES	AER PRICE REPORTING
contracts and swaps	met, participant must report price and other information on short-term transactions				information order, must report price and other information to AER

Source: AEMC.

While most of the changes required to extend the application of the transparency mechanisms to natural gas equivalents are expected to flow through from the NGL, some changes to the NGR may be required to:

- recognise the facilities and activities involved in the supply of natural gas equivalents that are not already captured by the relevant parts of the NGR (for example, blending facilities)
- set out any reporting obligations that would apply to the facilities and activities that are not already captured by the relevant parts of the NGR
- recognise any differences in the physical characteristics of the facilities and activities involved in the supply and use of natural gas equivalents compared to natural gas.

The specific areas of the NGR that may need to be amended include:

- Bulletin Board: Part 18 of the NGR may need to be amended to:
  - identify any facilities and activities involved in the supply of natural gas equivalents, that are not already covered by the existing definitions of the Bulletin Board facilities and activities (for example, blending facilities)
  - set out any additional information to be reported on the facilities and activities involved in the supply and use of natural gas equivalents.
- GSOO: Part 15D of the NGR may need to be amended to set out any additional content to be included in the GSOO on the facilities and activities involved in the supply and use of natural gas equivalents.
- VGPR:
  - the DWGM registration categories in Part 15A of the NGR may need to be amended to include any facilities involved in the supply of natural gas equivalents that are not already captured

    - Rules 323-324 in Part 19 of the NGR may need to be amended to set out any specific information to be reported by the facilities involved in the supply and use of the natural gas equivalents.
- Compression and storage terms and prices: Part 18A of the NGR may need to be amended if there is any additional facility specific information to be reported by compression and storage service providers involved in the supply of natural gas equivalents.
- AER gas price reporting functions: Part 17 of the NGR may need to be amended if there is any specific price information to be reported for natural gas equivalents.

QUESTION 8: EXTENSION OF THE TRANSPARENCY MECHANISMS TO NATURAL GAS EQUIVALENTS

1. Except for blending facilities are there any other facilities or activities involved in the supply or use of natural gas equivalents that are not already captured by:
    a. the BB facilities listed in rule 141 of Part 18 of the NGR?
    b. the DWGM registration categories in rule 135A of Part 15A of the NGR?
2. If the information to be reported by facilities involved in the production, transportation, storage, compression and or use of natural gas equivalents is to be based on the information reported by their natural gas counterparts, are any amendments required to reflect differences in the physical characteristics of these facilities compared to natural gas facilities for:
    a. the Bulletin Board reporting obligations in Part 18 of the NGR?
    b. the GSOO content in rule 135KB of Part 15D of the NGR?
    c. rules 323-324 in Part 19 of the NGR?
    d. the compression and storage reporting obligations in Part 18A of the NGR?
    e. the price information to be published by the AER in proposed rule 140B in Part 17 of the NGR?
3. Should blending facilities be treated as production facilities for the purposes of the Bulletin Board, GSOO and VGPR, or should specific reporting obligations be developed for these facilities? Why? If you think specific reporting obligations are required, what should these be?
4. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the five transparency mechanisms were to be extended to natural gas equivalents? Why? If you think there are other issues, what are they and what amendments are needed?

4.2.2 Extending the transparency mechanisms to constituent gases

In contrast to natural gas equivalents, the transparency mechanisms will not automatically apply to the facilities and activities involved in the supply of constituent gases. Rather, amendments would need to be made to Parts 15A, 15D, 17, 18, 18A and 19 of the NGR if the five transparency mechanisms are to be extended to the facilities and activities involved in the supply of constituent gases (for example, hydrogen production and storage facilities). Similar to the amendments outlined in the section above, these parts of the NGR would, where relevant, need to be amended to:

- recognise the facilities and activities involved in the supply of constituent gases
- set out the reporting obligations that these facilities and activities would be subject to
- recognise any differences in the physical characteristics of the facilities and activities involved in the supply and use of constituent gases compared to natural gas.

However, it is possible that extending some, or all, of these transparency mechanisms to constituent gases could be deferred to a future process. Deferral may be appropriate if the volume of natural gas equivalents is expected to be relatively small in the initial stages of the market's development.

Alternatively, if extending the application of the transparency mechanisms will be part of the initial rules package, then this review process should also consider the reporting obligations to apply to the facilities and activities involved in the supply of constituent gases.

The Commission's preliminary view is that if these reporting obligations are to be implemented as part of the initial rules, then the facilities and activities involved in the supply of constituent gases should be subject to equivalent reporting obligations as their natural gas counterparts. For example, the producer of a constituent gas should be subject to equivalent reporting obligations to natural gas producers. Some modifications to these reporting obligations may, however, be required to reflect differences in the physical characteristics of these facilities compared to natural gas facilities.

QUESTION 9: EXTENSION OF THE TRANSPARENCY MECHANISMS TO CONSTITUENT GASES

1. Do you think the following transparency mechanisms should be extended to the facilities and activities involved in the supply of constituent gases as part of the initial rules package or should the application of one or more be deferred until a later process? Why?
    a. the Bulletin Board
    b. the GSOO
    c. the VGPR
    d. the compression and storage terms and prices
    e. the AER's gas reporting functions.

2. If you think the transparency mechanisms should be extended as part of the initial rules package:
    a. What facilities do you think need to be captured?
    b. Do you think the facilities and activities involved in the supply of constituent gases should be subject to equivalent reporting obligations as their natural gas counterparts, or are some modifications required to reflect differences in the physical characteristics of these facilities?
3. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the transparency mechanisms were to be extended to constituent gases? Why? If you think there are other issues, what are they and what amendments are needed?

5 FACILITATED GAS MARKETS

The national gas regulatory framework provides for a number of types of facilitated markets for wholesale gas and gas transportation capacity trading in eastern Australia. These facilitated markets complement the trading of wholesale gas and gas transportation capacity through bilateral contracts, providing greater transparency and improved price discovery.

The short term trading market (STTM), which has hubs in Adelaide, Brisbane and Sydney, and the Victorian declared wholesale gas market (DWGM) operate at the boundary of transmission pipelines and distribution systems and, among other things, facilitate the trading of gas to retailers for onward supply to distribution-connected end-use customers.

This chapter sets out:

- an overview of the regulatory framework in relation to the STTM and then the DWGM
- how the facilitated markets could be used to accommodate the trading of natural gas equivalents
- issues for consultation, which include:
  - registration categories
  - offsetting UAFG
  - other settlement and allocation issues
  - metering and heating values
  - gas specification
  - the management of blending constraints.

5.1 Overview of the regulatory framework for facilitated gas markets

The focus of this chapter is the STTM and the DWGM. As discussed in the box below, unlike the STTM and DWGM, the other facilitated markets relate only to transmission pipelines. As a result, the Commission does not intend to consider the gas supply hub or day-ahead auction in this review.

BOX 3: THE GAS SUPPLY HUB AND THE DAY-AHEAD AUCTION

The gas supply hub (GSH) is a centralised trading, settlement and clearing facility that is operated by AEMO and can be used by market participants for the trading of gas, and for the trading of secondary transportation capacity through the capacity trading platform (CTP). The GSH is used to facilitate gas trades at the Wallumbilla and Moomba trading hubs, which each relate to a number of physical locations on major transmission pipelines. The CTP facilitates secondary transportation capacity trades on transmission pipelines and stand-alone compression facilities across the east coast (excluding the DTS) and Northern Territory.

To complement the CTP, AEMO conducts a day-ahead auction (DAA) of contracted but un-nominated capacity on transmission pipelines and stand-alone compression facilities. The DAA allows capacity that has been contracted by shippers on a firm basis but has not been nominated for use on the gas day to be auctioned on a day-ahead basis at a reserve price of zero. The DAA applies to all transmission pipelines on the east coast (excluding the DTS) with a nameplate rating of 10 TJ/day or more that are supplying more than one user.

Because of the technical issues associated with the transportation of hydrogen blends through existing transmission pipelines, the assumption being made in this review is that only natural gas will be transported through transmission pipelines for the foreseeable future. In such circumstances, the GSH and DAA would continue to be associated with the trading of natural gas, and capacity for the transportation of natural gas, only and existing frameworks could therefore continue to operate without modification.

5.1.1 Short term trading market

The STTM is a facilitated wholesale gas market that uses participant offers and bids to schedule deliveries and withdrawals from gas pipelines at three distinct hubs for the next gas day. The STTM is a regulated market operated by AEMO and participation in it is mandatory. Further detail of the policy objective and relevant provisions for the STTM are provided in the box below and in appendix B.3.

BOX 4: POLICY OBJECTIVE, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objective

The objective of the STTM is to provide participants with a transparent and efficient market based mechanism to trade imbalances, purchase gas on a short-term basis and efficiently allocate gas during system constraints and emergencies. It is also intended to provide the market with clearer signals about the nature and cost of supply and transmission constraints.[1]

Relevant provisions

NGL: Chapter 2 (Part 6).

NGR: Parts 15A, 15B and 20.

Jurisdictional application

Currently in operation in Adelaide, Brisbane and Sydney.

Note: 1) AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, stage 1 final report, 23 July 2015, p. 88.

STTM trading locations and participants

There are currently three STTM hubs in Adelaide, Brisbane and Sydney. The hubs in Adelaide and Sydney are each supplied by two transmission pipelines, while the Brisbane STTM hub is supplied by one transmission pipeline (see Figure C.1 in appendix C for a map depicting the different STTM hubs).

In the STTM, gas is traded at 'custody transfer points' between 'STTM shippers' and 'STTM users':

- A custody transfer point is a point at which gas passes from a transmission pipeline, storage facility or production facility (collectively, STTM facilities) to a distribution system or transmission connected end-user. In Adelaide and Sydney, the STTM hubs include only one distribution system, there are two distribution systems in Brisbane.
- STTM shippers are generally parties supplying gas to the market from STTM facilities (although they may also bid to withdraw gas from the hub).
- STTM users are retailers or self-contracting users that have a contract to use a distribution system, or to withdraw gas for consumption from a transmission pipeline, connected at an STTM hub.

AEMO manages the market, producing market schedules, but has no role in pipeline or facility operation. In the STTM, pipeline and storage infrastructure is operated and scheduled by the infrastructure owners. While the same rules apply, each hub is scheduled and settled separately, and AEMO manages and monitors the settlement process across all hubs.

Pipeline capacity arrangements

The STTM overlays a gross pool market design onto existing pipeline arrangements. The relevant transmission pipelines operate on a contract carriage basis, meaning that access to them is allocated on the basis of contracts between the pipeline service provider and the shipper. Rights to use pipeline capacity to the hub must be registered with AEMO.

Importantly, however, under the STTM scheduling process, shippers with firm gas haulage rights are not prioritised over those with non-firm or as-available capacity (other than to resolve tied offer prices). If a pipeline is constrained, an as-available shipper may displace a firm capacity shipper by offering gas at a lower price. In this situation, the as-available shipper pays a capacity charge, and the firm capacity shipper who is displaced receives a capacity payment based on the amount of gas it offered into the market below the market price but which was not able to be scheduled.

Trading on the STTM

The STTM market design is based around two principal mechanisms:

- a day-ahead ex ante commodity market
- an on-the-day mechanism to manage deviations.

The ex ante commodity market is where STTM shippers offer to supply gas and STTM users bid to purchase gas for delivery the following gas day. Following the submission of offers and bids, AEMO produces market schedules and determines the ex ante price based on the intersection of demand and supply. All the gas that flows at that hub in accordance with the ex ante market schedule on the gas day is settled at the ex ante price.

The role of the on-the-day mechanism is to resolve the variations that will occur between the ex ante schedules and actual flows on the gas day, that is, to balance the market. The primary tool used by AEMO to manage such deviations is the market operator service (MOS).[37] MOS is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are less than demand.

MOS is procured through a competitive process each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges. Shippers may avoid deviation payments and charges if they submit a market schedule variation to AEMO to account for intra-day renominations.

5.1.2 Declared wholesale gas market

The Victorian DWGM is a wholesale gas market that operates on an intra-day basis and uses participant injection and withdrawal bids to manage supply, demand and linepack on the DTS. The DWGM is a regulated market and participation in it is mandatory.

In contrast to the STTM — where gas is traded at the intersection of transmission pipelines and distribution systems — the DWGM encompasses the entire DTS. The DTS is subject to an open access regime (referred to as market carriage), instead of the contract carriage arrangements used elsewhere. Under this model, the pipeline owner makes its pipeline available to AEMO, with access to it being allocated in line with market (the DWGM) outcomes.

From an operational perspective, the physical characteristics of the DTS (specifically, that it is essentially a meshed network, the amount of gas it can store is relatively small and the capacity is such that it cannot be relied upon to manage significant deviations between demand and supply) mean it must be closely managed by AEMO to ensure that gas flows in the manner required and system integrity is maintained. Further detail of the policy objective and relevant provisions for the DWGM are provided in the box below and in appendix B.4.

BOX 5: POLICY OBJECTIVE, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objective

The objectives of the DWGM include:[1]

- providing participants with a transparent and efficient market-based mechanism to trade imbalances, purchase gas on a short-term basis and efficiently allocate gas during system constraints and emergencies
- supporting full retail contestability by reducing the barriers to entry by new retailers through open access to the DTS and the market mechanisms

37 There is also an additional, fall-back mechanism available to AEMO to balance supply and withdrawals at a hub in the form of 'contingency gas'. Contingency gas is described in appendix C.

- encouraging diversity of supply and upstream competition through DWGM pricing transparency and open access to the DTS.

Relevant provisions

NGL: Chapter 2 (Part 6).

NGR: Parts 15A, 15B and 19.

Jurisdictional application

Currently in operation in Victoria.

Note: 1) AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 118.

DWGM trading locations and participants

The DTS transports gas from Longford in the east (historically, the major Victorian supply point) to, and from, Culcairn in the north (connecting to the Moomba Sydney Pipeline in NSW) and Iona in the west (connecting to South Australia by the SEAGas Pipeline, Otway gas production and underground gas storage facilities) (see Figure C.1 in appendix C).

There are over 120 system withdrawal points in the DTS that allow gas to flow from the DTS into the Victorian distribution systems, to large gas customers, into storage facilities, or to other transmission pipelines. These are supplied by system injection points that allow gas to flow from production fields and plants, storage facilities, and other transmission pipelines into the DTS.

In the DWGM, gas is traded between market participants. In general, Part 19 of the NGR, which governs the DWGM, does not differentiate between different types of market participants. The requirements on registration of participants are instead governed by Part 15A of the NGR, which covers both the registration of the operators of relevant physical facilities and of market participants.

The following are registered participants with respect to physical facilities:

- the declared transmission system service provider (the service provider for the DTS)
- distributors, who are the service providers for each declared distribution system (DDS) connected to the DTS
- any interconnected transmission pipeline service providers whose pipelines are connected to the DTS
- producers, who inject natural gas into the DTS
- storage providers, whose storage facilities are connected to the DTS
- transmission customers, which are end users that withdraw gas directly from the DTS.

The following are market participants:

- producers, who sell gas — and may also buy gas — in the DWGM
- storage providers, who buy or sell gas in the DWGM

- transmission customers, who buy gas in the DWGM
- retailers that sell gas that has been transported through the DTS
- traders, which include any other person that buys or sells gas in the DWGM.

The DWGM can be described as a virtual trading hub, in that the point at which title is transferred is a notional point covering the whole DTS rather than being at a specific physical point. Formally, custody of gas passes from market participants to AEMO at system injection points — the connection points where gas flows into the DTS — and back to market participants at system withdrawal points, where gas flows out of the DTS.

Like the STTM, in the DWGM, AEMO manages the market and is responsible for determining market schedules and undertaking settlement. However, unlike the STTM, AEMO is also responsible for the operation of the physical transmission pipeline system (in this case, the DTS), although it is not the owner.

Pipeline capacity arrangements

Transportation of gas through the DTS occurs under an open access arrangement known as market carriage. Under this arrangement, the DTS service provider (APA VTS Australia (Operations) Pty Ltd) must make the transmission system available to AEMO as the operator, and pipeline capacity is allocated through the DWGM. Market participants utilising the DTS cannot contract for firm capacity on the pipeline and are instead implicitly allocated capacity through the DWGM when their injection bids or withdrawal bids (or forecasts) are scheduled.

However, market participants may hold or be allocated Authorised Maximum Daily Quantity (AMDQ) or AMDQ credit certificates (AMDQ cc) (collectively known as AMDQ), which provide some limited physical and financial benefits. These benefits and the processes for obtaining AMDQ are described in appendix D.4.

From 1 January 2023, the current AMDQ regime will be replaced with a system of entry capacity certificates that provide injection tie-breaking benefits and exit capacity certificates that provide withdrawal tie-breaking benefits.[38]

Trading on the DWGM

It is compulsory for market participants within the DTS to trade all gas through the DWGM, including for participants who already own the gas that they intend to withdraw. Before the beginning of each gas day, market participants are required to provide AEMO with their injection and withdrawal bids and a range of information on demand.

Based on their bids and forecasts, AEMO produces operating schedules specifying each participant's hourly gas injections and withdrawals at each system injection point and withdrawal point. The beginning-of-day schedule covers the full gas day from 6.00 am, with further scheduling times at 10.00 am, 2.00 pm, 6.00 pm and 10.00 pm, where updated schedules covering the remainder of the gas day are issued.

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38 AEMC, *DWGM improvement to AMDQ regime*, rule determination, 12 March 2020.

AEMO also produces complementary pricing schedules that determine the ex ante market price that applies, and which is updated at the beginning of each scheduling period. There are three main types of settlement payments and charges:

- imbalance payments, used to settle trades in accordance with the market schedule
- deviation payments, which apply to variations against the market schedule
- ancillary payments, which are used to manage network congestion, and the uplift payments that fund them.

Imbalance payments, which can be positive or negative, are payments for the net difference between scheduled injections and withdrawals of gas by a market participant. The imbalance payment for each market participant is calculated based on the imbalance quantities from the 6.00 am beginning-of-day schedule, plus subsequent payments based on changes in imbalance quantities at each reschedule priced at the updated ex ante price applying to that reschedule.

Deviation payments are used to settle differences between market participants' scheduled and actual behaviour. In contrast to imbalance payments therefore, deviation payments are calculated on an ex post basis. Deviations are valued at the next scheduled price because they will have physical and financial impacts on the outcomes of the next schedule. For example, a deviation in the 10.00 am-2.00 pm interval is settled at the 2.00 pm reschedule price.

Ancillary payments are required when the system is congested and there is a need to schedule gas out of the normal merit order. The payments fund compensation to market participants who inject gas that was bid above the market price. More rarely, ancillary payments are paid when a market participant is scheduled to withdraw gas that is more expensive than its bid price. The costs associated with making ancillary payments are recovered from market participants through uplift payments, as described in appendix D.

5.2 How the STTM and DWGM could be extended to natural gas equivalents

In considering the issues relating to integrating natural gas equivalents, there appear to be two broad approaches that could be taken to facilitate their trading in distribution systems which are associated with facilitated markets. These are:

- facilitate the trading of the natural gas equivalents through the market in question (the relevant STTM hub or the DWGM), or
- continue to trade only natural gas through the relevant facilitated market, and implement separate market arrangements associated with natural gas equivalents (such as in relation to blending) downstream of the facilitated market.

5.2.1 Trading natural gas equivalents through facilitated markets

The market designs of the STTM and DWGM are predominately based around the trading of gas that is delivered to the hub by transmission pipelines (in the case of the STTM) or of gas that is transiting a specified transmission system (in the case of the DWGM).

As previously noted, an assumption being made in this review is that only natural gas will be transported through transmission pipelines for the foreseeable future. Natural gas equivalents will only affect distribution systems, for instance through the injection of low-level hydrogen blends into a distribution system in place of natural gas.

A key difference between the STTM and the DWGM is that the STTM provides for injections directly into distribution systems, and the DWGM does not. An 'STTM facility' includes a storage facility or production facility connected to a distribution system. An example is the Newcastle gas storage facility which is connected to Jemena Gas Network's distribution system in NSW.

In contrast, the DWGM only provides for the scheduling of injections at system injection points on the DTS. However, the Victorian Minister for Energy, Environment and Climate Change has submitted a rule change request that seeks to introduce distribution connected facilities to the Victorian gas market. The Commission is consulting on this rule change concurrently with this review.[39]

In the STTM — and the DWGM, if the proposed rule is made — natural gas equivalents could therefore be traded through the facilitated market in question. A participant would submit an ex ante offer (STTM) or an injection bid (DWGM) relating to a blending facility to AEMO and, if this was less than or equal to the clearing ex ante market price, it would be scheduled to inject.

Given that a hydrogen blending facility would withdraw natural gas prior to blending, and then inject the resulting blend back into the distribution system, participants would also need to make corresponding withdrawal bids for hydrogen blending facilities.

The Commission understands that, initially, most natural gas equivalents are unlikely to be cost competitive with natural gas. Participants at blending facilities would therefore require financial support in order for their offers or injection bids to be scheduled (that is, to be less than or equal to the clearing price). The form of any such financial support is outside the scope of this review.

The presence of an additional financial support mechanism would likely mean that the facilitated market would not be the primary means through which blending would be funded and, consequently, investment and operational decisions may be driven primarily by extrinsic factors. This may limit the benefits of including blending facilities in facilitated markets and, at much higher levels of uptake than are currently contemplated, may have the potential to distort price signals in those markets.

Conversely, it may be possible to integrate natural gas equivalents into facilitated markets at relatively low cost. In the case of the STTM, which already provides for distribution connected facilities, achieving this integration may be straightforward and require relatively few changes. In the case of the DWGM, the Victorian Minister for Energy, Environment and Climate Change considers that:[40]

39 AEMC, *DWGM distribution connected facilities*, consultation paper, 21 October 2021.

40 Hon Lily D'Ambrosio MP, *Rule change proposal to enable gas facilities connected to a declared distribution network to participate within the Victorian declared wholesale gas market*, 8 September 2021, p. 10.

ensuring a streamlined, consistent and transparent process for the connection and integration of these facilities into the market will minimise the costs of these facilities participating in the market.

5.2.2 Trading natural gas equivalents outside of facilitated markets

An alternative to trading natural gas equivalents through the STTM and DWGM would be to continue to trade only natural gas through these markets, and to instead implement separate arrangements governing the introduction of natural gas equivalents into distribution systems.

Initial blending trials appear likely to involve only relatively small volumes, which will be used by distributors to offset unaccounted for gas (UAFG), and this might be facilitated through only relatively minor — albeit detailed — changes to regulatory and market frameworks. These potential changes are discussed further in the next section.

However, where the volume of constituent gases as a proportion of gas stream injected into the distribution system goes beyond the relatively low levels associated with UAFG,[41] a new mechanism would be required through which retailers and users procure, or are provided with, the blend. Some possible approaches could be:

- distributors procuring or producing the blend, with the costs of this being recovered from retailers and users through network tariffs, or
- retailers and users procuring the blend from competitive providers, paying the competitive providers for the blend directly.

Such arrangements will, in any event, be required in distribution systems not associated with a facilitated market. Given the current uncertainty as to which procurement approaches may initially be adopted, and how the renewable gas industry will develop over time, there may be merit in not making significant changes to the facilitated market frameworks at this point in time.

However, as discussed below, even if the trading of natural gas equivalents remained outside the facilitated markets for some time, some changes would still need to be made to the market frameworks and system (for example, registration and settlement) to appropriately account for the introduction of the natural gas equivalents into the associated distribution systems. Further, as time progresses, and the provision of blends increases in volume and decreases in cost, the operation of two parallel market processes may create material inefficiencies. Price discovery may be compromised, resulting in the inefficient allocation of natural gas and gas blends to consumers and inefficient investment in gas production, transportation and blending facilities.

41 For example, the percentage of UAFG in gas networks in NSW was on average 2.6% between 2014 and 2019: NSW Department of Planning, Industry & Environment, *New South Wales 2018-19 Gas Networks Performance Report*, https://www.energy.nsw.gov.au/sites/default/files/2020-07/2018-19%20Gas%20Networks%20Performance%20Report%2030%20Jun%202020.pdf.

QUESTION 10: TRADING NATURAL GAS EQUIVALENTS IN THE FACILITATED MARKETS

1. Do you think natural gas equivalents should be traded through the facilitated markets, or outside of the facilitated markets?
2. What do you consider are the implications of these two options, in terms of required regulatory changes, costs of implementation and potential market inefficiencies?

5.3 Issues for consultation

The Commission has identified a number of potential issues in the regulatory framework for facilitated markets in relation to the integration of natural gas equivalents. These are:

- registration categories
- offsetting UAFG
- other settlement and allocation issues
- metering and heating values
- gas specification
- the management of blending constraints.

This section discusses each of these issues, including by reference to the possible overarching approaches introduced in the previous section.

5.3.1 Registration categories

If natural gas equivalents are to be integrated into the facilitated markets, appropriate registration categories would be required in the NGR to accommodate facilities and participants in the creation of these products, including through the injection of blends into the distribution system.

In the STTM, the NGR already provide for persons that are party to a contract with a producer or storage provider for the delivery of natural gas from a production or storage facility connected to the distribution system (or are a producer or storage provider supplying natural gas on their own behalf) to be registered as STTM shippers.[42]

Once changes to the definition of 'natural gas' have been made, this provision may automatically capture blending facilities producing natural gas equivalents. However, it may be preferable to amend the NGR to refer specifically to blending facilities, given that their characteristics are not identical to typical production facilities in that they also require the withdrawal of gas in order to produce the blend. It appears from rule 135ABA of the NGR, as noted above, that the rules could already accommodate multiple shippers using a single blending facility.

42 Rule 135ABA(1)(a) of the NGR.

The rules also already provide for AEMO to exempt persons from registration.[43] This may be a relevant option for shippers injecting blends from the type of very small blending facilities that are likely to form the basis of initial trials. However, this is not a process that has been commonly used to date and there is a lack of precedent as to its operation. For example, it is not certain whether it is possible to exempt a shipper only with regard to specific facilities. The Commission understands that AEMO is considering this matter in consultation with stakeholders.

As previously noted, the Victorian Minister for Energy, Environment and Climate Change has submitted a rule change request to facilitate distribution connected facilities within the Victorian gas market. If made, this rule would be likely to introduce new facility and market participant categories for the DWGM. The rule change request also contemplates whether smaller blending facilities, for example those unable to bid on a GJ basis because they produce less than 1 GJ/hour, should be included within the market but have reduced requirements (such as daily bidding).[44]

If an overarching approach was followed not to integrate distribution connected blending facilities into facilitated markets but instead to establish separate downstream markets, consideration would need to be given to the appropriate arrangements for the registration in retail gas markets of blending facilities and participants associated with those facilities. This would be likely to impact on Part 15A of the NGR, as well as the Retail Market Procedures (RMP) and, potentially, the regulations.

There may also be other drivers for the registration of facilities even if they do not participate in facilitated markets. For example, to require registered participants to disclose information to AEMO for the purposes of it preparing the VGPR.[45] It should be noted that registration for these purposes would likely need to also include facilities involved in the supply of constituent gases (see section 4.2).

QUESTION 11: FACILITATED MARKET REGISTRATION CATEGORIES

1. If natural gas equivalents are to be integrated into the facilitated markets, are new registration categories required to accommodate facilities and participants involved in the creation of these products, including through the injection of blends into the distribution system?
2. If flows associated with distribution-connected blending facilities are not scheduled in facilitated markets, are new registration categories required for blending facilities and associated participants or can they be exempted from registration?

43 Rule 135AG(1) of the NGR.

44 Hon Lily D'Ambrosio MP, *Rule change proposal to enable gas facilities connected to a declared distribution network to participate within the Victorian declared wholesale gas market*, 8 September 2021, p. 9.

45 Rule 324 of the NGR.

5.3.2 Unaccounted for gas

Initial trials of natural gas equivalents are likely to involve only very small volumes, below the levels of UAFG. Where UAFG is provided by distributors, the most straightforward approach to accommodating the introduction of such trials will likely be to amend the arrangements for UAFG.

The arrangements for UAFG vary between the DWGM and STTM, and between each STTM hub, and are described in appendix D and appendix C. In summary these arrangements are:

- in the Adelaide and Sydney STTM hubs, distributors are responsible for supplying UAFG
- in the Brisbane STTM hub, the local retailer is responsible for supplying UAFG, with the costs of this recovered from distributors
- in the DWGM, market participants' withdrawals are adjusted using a fixed UAFG benchmark factor to account for the impact of UAFG. An annual reconciliation against actual UAFG administered by AEMO results in payments to each distributor by retailers if the actual UAFG is better than the benchmark and payments by the distributor to retailers if it is worse.

Consequently, using gas blends to provide UAFG is likely to be most straightforward in Adelaide and Sydney. However, it should be noted that Sydney uses the matched allocation mechanism under which gas purchased by the distributor to offset UAFG can be excluded from the operation of the STTM.[46]

This raises the question of the operation of the matched allocation mechanism in a situation where the amount of gas procured by the distributor from shippers on connected transmission pipelines would no longer match the quantity of UAFG (because some UAFG was now being met by distribution-connected blending facilities). Another potential issue is that the definition of the matched allocation agreement in the rules suggests that such an agreement can only be in place between distributors, STTM pipeline operators and STTM shippers. This definition may need to be expanded to accommodate distribution-connected blending facilities.

In contrast, more detailed changes would likely be required in the DWGM.[47] Currently, if a distributor began injecting a blend into the distribution network, this would be in addition to UAFG due to the adjustment that is made to market participants' withdrawals to compensate for UAFG. As a result, the injected blended gas would represent a competing, unscheduled source of supply.

The Commission intends to consider this issue further, in conjunction with AEMO (in relation to the DWGM Procedures and the Victorian Retail Market Procedures (RMP)) and the Essential Services Commission (in relation to the UAFG benchmarking process).

46 Rule 500A of the NGR.

47 Rule 235(8) of the NGR

QUESTION 12: UNACCOUNTED FOR GAS IN THE FACILITATED MARKETS

1. Do you think initial trials involving the injection of natural gas equivalents into the distribution system should be accommodated by amending jurisdictional arrangements for UAFG?
2. If so, how will this impact the operation of the matched allocation mechanism (as used by the distributor in the Sydney STTM hub)?
3. What changes would be required to UAFG arrangements in the DWGM?

5.3.3 Other settlement and allocation issues

As injections of blends increase beyond the level of UAFG, the potential for the distortion of settlement in the STTM, DWGM and RMP increases because the additional quantities of blended gas will displace natural gas that should otherwise have been injected at the hub. As a result, arrangements will be required to allocate injections of blends to market participants and for those injections to be allocated to users in the relevant network section and balanced against withdrawals.

If distribution connected blending facilities were not integrated into the facilitated markets (that is, made subject to market schedules in the STTM or operating and pricing schedules in the DWGM), settlement in the facilitated markets would need to exclude the distribution injections, together with a corresponding amount of end use consumption (so that settlement continued to balance).

The way this excluded consumption could be treated might depend on the arrangements for the trading of, and targets or obligations for, gas blends. For instance, the withdrawal allocations of one participant might be adjusted if it had purchased the injected blend. Alternatively, allocations of all participants might be equally scaled down as part of an obligation under which they were required to purchase the injected blend in preference to natural gas.

Equally, settlement issues also need to be addressed if distribution connected blending facilities were to be integrated into the facilitated markets. This may be relatively straightforward in the STTM where it appears that such a facility could be treated in a very similar manner to existing distribution-connected production and storage facilities.

In relation to the DWGM, the Victorian Minister's rule change request canvasses a range of issues associated with settlement. In particular, it notes that allocations are currently only contemplated for injections and withdrawals into and from the DTS, and not at a Dedicated Distribution System (DDS) level.[48] If injection facilities connect to a DDS and are scheduled within the DWGM, then the gas injected will need to be allocated to one or more market participants.

48 Hon Lily D'Ambrosio MP, *Rule change proposal to enable gas facilities connected to a declared distribution network to participate within the Victorian declared wholesale gas market*, 8 September 2021, p. 6.

The preferred option outlined in the rule change request is for such distribution injections to be treated equivalently to transmission injections. Under this approach, demand would be defined to include all withdrawals from the transmission and distribution systems, and would equal the sum of transmission and distribution injections.

However, the rule change request also outlines two alternative approaches. The first is where distribution injections would either be directly netted off the withdrawals of a market participant (the market participant that had purchased the blend); the second where distribution injections would be treated in their own right in a way equivalent to negative demand.[49]

The rule change request highlights that consideration would also need to be given to demand forecasts provided to AEMO by market participants at a system withdrawal point level.[50] Where they are used by AEMO for operational purposes, it will be important to be clear on what basis demand forecasts are specified, that is, whether they represent gross demand or are net of distribution injections.

In both the STTM and DWGM, there is also a question of the treatment of facilities exempted from registration or falling below a materiality threshold.[51] While such facilities might not be subject to market schedules (in the STTM) or operating and pricing schedules (in the DWGM), it would still be important to recognise them in settlement in order to ensure that settlement balances.[52] A parallel can be drawn to small generators in the national electricity market. These generators can be exempted from scheduling but must still be captured in settlement (for instance, through a retailer or a small generator aggregator).

QUESTION 13: SETTLEMENT ISSUES IN THE FACILITATED MARKETS

1. If distribution connected blending facilities are not integrated into the facilitated markets, what settlement issues may arise?
2. If distribution injections and corresponding end use consumption need to be excluded from settlement, how should excluded consumption be treated? What factors might affect this?
3. If distribution connected blending facilities are integrated into the facilitated markets, are settlement issues in the STTM likely to be relatively straightforward to resolve? Why?
4. How should facilities exempted from registration, or that fall below a materiality threshold, be treated under settlement arrangements in the facilitated markets?

49 Hon Lily D'Ambrosio MP, *Rule change proposal to enable gas facilities connected to a declared distribution network to participate within the Victorian declared wholesale gas market*, 8 September 2021, Appendix 1.

50 Rule 208 of the NGR.

51 The rule change request notes that, if a facility produces 1 GJ/hour or less, then the hourly quantity of gas may not be able to be bid into the DWGM. In the STTM, offers and bids must be made in whole gigajoules (GJ).

52 This might take the form of a negative uncontrollable withdrawal in the DWGM, for example.

5.3.4 Metering and heating values

If natural gas equivalent blends of different compositions are injected into different parts of a distribution system, there will be a need to ensure the energy content of these blends can be accurately measured at these different locations (see appendix E for further detail on metering arrangements and heating values). This will be particularly important for blends including hydrogen.

The Commission understands that existing gas meters in distribution networks may be able to accurately record the volume of a low-level hydrogen blend within acceptable deviations. However, the lower energy content of hydrogen means that to meter the same amount of energy, a greater volume of the blend must be recorded as compared to natural gas.

To turn a metered volume into a measure of consumed energy (in MJ), the volume of gas used must be multiplied by a pressure factor and a heating value. Consequently, local heating values may need to be determined for specific parts of each distribution network and calculated more often than under current arrangements.

In general, it is the RMP that specify how distributors are to calculate consumed energy, including how heating values are to be used in settlement. As a result, these issues are relevant to AEMO's review of its procedures, although there are likely to be interactions with jurisdictional instruments which also contain requirements relating to heating values.

The DWGM rules in Part 19 of the NGR also contain extensive requirements in relation to gas metering and quality monitoring in DDSs in Victoria.

Regarding the heating value specifically, in Victoria one heating value is determined for a gas day by AEMO for non-daily metered customers and used by all distributors to calculate consumed energy.[53] Consequently, there may be a need to move to multiple values calculated in different parts of each DDS to accommodate the different uses of natural gas equivalent gases.

Despite the extensive provisions in Part 19 of the NGR, it is not clear that the NGR would place any restriction on this. Rule 303(10) of the NGR only requires that:

> the source of data used for determining the energy content of gas flowing through a metering point at a metering installation (including heating value, gas composition and relative density) must be determined by AEMO, after consultation with the responsible person.

The responsible person is the party responsible for providing a metering installation.

Similarly, the NGR already appears to give AEMO sufficient power to require that meters be capable of determining the energy content of gas (which would assist it in specifying locationally-varying heating values), even if AEMO does not commonly make use of this power currently. For instance, rule 303(3) of the NGR provides that:

53 Essential Services Commission, *Gas Distribution System Code*, version 14.0, Schedule 1.

> a metering installation at a distribution delivery point must be capable of measuring the volume of gas flowing through the metering point unless AEMO reasonably requires that metering installation also to be capable of determining the energy content of gas flowing through the metering point.

Nevertheless, there may be a need for amendments to the NGR to facilitate the determination of more granular heating values and any other matters relating to the metering provisions contained in Part 19 of the NGR for the DWGM.

QUESTION 14: METERING AND HEATING VALUES IN THE FACILITATED MARKETS

1. Does the NGR restrict distributors' ability to calculate heating values in different parts of the distribution system to accommodate the different uses of natural gas equivalent gases in the facilitated markets?
2. Are amendments required to the NGR to facilitate the determination of more granular heating values and any other matters relating to the metering provisions for the DWGM?

5.3.5 Gas specification

In both the STTM and DWGM, the gas specification is based around AS 4564 – 2005. In relation to the STTM, Part 20 of the NGR defines the 'gas quality specification' as:

> (a) the gas quality specification contained in Australian Standard AS 4564 – 2005, Specification for general purpose natural gas (as amended or replaced from time to time); and
>
> (b) any additional gas quality specifications contained in the applicable access arrangement for an STTM distribution system at that hub.

Rule 418(3) of the NGR further provides that:

> each STTM Shipper must ensure that natural gas supplied by it to a hub complies with the gas quality specification for that hub, unless otherwise agreed in writing by the relevant STTM distributor or specifically authorised under a law of the relevant adoptive jurisdiction.

These provisions may allow for AS 4564 – 2005 to be augmented or replaced, either through an access arrangement or through jurisdictional legislation, in order to accommodate blending in certain parts of STTM distribution systems. However, it may be useful to clarify this in the NGR. Consideration should also be given to the impacts on connected transmission pipelines, if any, noting that the STTM allows for at least notional flows from distribution systems to transmission pipelines.

In relation to the DWGM, Part 19 of the NGR defines the 'gas quality specifications' as:

> (a) the standard gas quality specifications; or
>
> (b) a gas quality standard approved by AEMO in respect of that system injection point pursuant to rule 287(1).

The 'standard gas quality specifications' are defined as:

> (a) the quality specifications contained in AS 4564 – 2005 (as amended or replaced from time to time); or
>
> (b) if those gas quality specifications have been added to or otherwise modified by or under applicable legislation (principal or subordinate) of the Commonwealth or a State — those gas quality specifications as added to or otherwise modified.

In general, the provisions of Part 19 of the NGR governing the gas specification relate to injections into the DTS at a system injection point. Rule 287(1) of the NGR allows AEMO to approve a written agreement providing for the injection of gas at a system injection point that does not comply with the standard gas quality specifications. In addition, rule 289 of the NGR requires that each registered participant must use its reasonable endeavours to ensure that any gas it injects at a system injection point complies with the gas quality specifications for that system injection point.

The exception is rule 287(5) of the NGR which provides that:

> AEMO may determine for a particular transmission delivery point a gas quality standard that differs from the standard gas quality specifications if all Registered participants who withdraw gas at that transmission delivery point agree to the determination.

The NGR do not, therefore, currently directly govern the gas specification on a DDS. However, in practice, this will be influenced by the NGR in respect of the gas specification on the DTS and by AEMO's ability to approve different specifications at DTS injection and withdrawal points.

This raises the question if AEMO should be given the ability to directly determine the gas specification on distribution systems (which would apply to injections made by distribution-connected facilities) or whether a similar power should be given to another party, such as the relevant service provider. Although the NGR does not directly govern the gas specification applying to a DDS, it may be useful to amend the NGR in this regard.

Further, the Commission notes that Part 19, unlike the rest of the NGR, refers to 'gas' which is defined as including natural gas and processable gas. This approach is likely to be a legacy of Part 19's beginnings as the Market and System Operations Rules and was intended to bring production facilities within the scope of the reporting framework for the VGPR. Consequently, when revisiting the definition of natural gas in the NGL and NGR, and introducing concepts such as natural gas equivalents and constituent gases, it will be important to ensure that Part 19 of the NGR uses these terms in such a way that these obligations still function correctly.

QUESTION 15: GAS SPECIFICATION IN THE FACILITATED MARKETS

1. In relation to the STTM, do you think Part 20 of the rules should be amended to clarify that AS 4564 – 2005 can be augmented or replaced to accommodate blending in certain parts of STTM distribution systems? Are any other changes required, including to accommodate impacts on connected transmission pipelines?
2. In relation to the DWGM, do you think Part 19 of the rules should be amended to give AEMO (or another party) the ability to directly determine the gas specification on distribution systems?

5.3.6 Management of blending constraints

The current regulatory frameworks make no provision for assigning responsibility for the creation of a natural gas equivalent blend and ensuring that this remains consistent with the revised gas specification governing the parameters of the blend.

That responsibility could be placed on the party operating the blending facility and/or the shippers or participants who are commercially responsible for the natural gas blend produced. Responsibility for monitoring and enforcement of compliance with the revised gas specification is a role that could be assigned to the relevant distributor.

However, for the DWGM and the associated distribution systems, an alternative arrangement could be to assign the operational role to AEMO. This is relevant for the DWGM as AEMO currently has operational control over the DTS and is responsible for managing constraints on it. Consequently, AEMO might be well-placed to manage blending constraints in Victoria. A blending constraint would arise when a blending facility attempts to inject more of blend into a distribution system than can be accommodated under the revised gas specification.

To undertake this function, AEMO would require systems to monitor gas quality and to curtail injections from each blending facility, as well as a legal basis for doing so. AEMO currently has no operational role in distribution networks and so to allocate it any such function would likely require changes to a range of legal and regulatory instruments, including the NGR.

QUESTION 16: BLENDING CONSTRAINTS IN THE FACILITATED MARKETS

1. Who should be responsible for the creation of natural gas equivalent blends and ensuring that these remain consistent with a revised gas specification?
2. In the DWGM, should AEMO be given operational control over the distribution system to manage blending constraints? If so, what changes to the rules would be required?

QUESTION 17: OTHER IDENTIFIED ISSUES IN THE FACILITATED GAS MARKETS

1. Do the identified issues in the NGR and changes required cover all necessary changes to facilitate the trade of natural gas equivalents in the DWGM and STTM?
2. Are there any other issues the Commission should be aware of?
3. Are all of these changes required now for natural gas equivalents? Could some of these changes be made at a later date, or when other gas products are taken into consideration?
4. Are there any transitional issues?

6 REGULATED RETAIL MARKETS

The regulated gas retail markets facilitate gas retail competition by enabling retailers to sell natural gas to residential and business customers in New South Wales, the Australian Capital Territory, Queensland, South Australia and Victoria supplied by distribution systems. Anyone that functions as a distributor, retailer or self-contracting user must register in the applicable retail gas market.

This chapter sets out:

- an overview of the regulatory framework as it currently relates to regulated retail markets
- issues for consultation, which include:
  - initial issues — including registration categories, settlement and metering — that may need to be dealt with as part of this review
  - other potential issues — including those relating to cost and cost recovery — that could be assessed in the future.

6.1 Overview of regulated retail markets

Under the national gas regulatory framework, AEMO administers the retail markets in New South Wales, the Australian Capital Territory, Queensland, South Australia and Victoria.

The functioning of the retail markets is managed by AEMO through retail market procedures.[54] The retail market procedures in all jurisdictions regulate:

- the process of transfer for customers between retailers
- retailer of last resort processes
- processes for metering installations, meter reads and communication of metering information.[55]

In addition, the retail market procedures in jurisdictions other than Victoria cover:

- arrangements under which the gas injected and withdrawn from non STTM network sections is balanced and allocated to retailers
- for STTM distribution systems, STTM system allocation processes
- arrangements in relation to unaccounted for gas.

The inclusion of natural gas equivalents in the gas market frameworks will therefore primarily be managed by AEMO through these market procedures.

However, the NGL and NGR govern registration of retail market participants and the making of retail market procedures by AEMO and the Commission has considered whether changes may be required to these provisions to accommodate natural gas equivalents in the retail market frameworks.[56]

54 https://aemo.com.au/en/energy-systems/gas/gas-retail-markets/procedures-policies-and-guides

55 Jurisdictions regulate technical aspects of metering under local regulations.

56 Appendix B.5 provides an overview of the relevant provisions contained in the NGL and NGR and their policy intent.

BOX 6: POLICY OBJECTIVE, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objective

The objectives of the Regulated Retail Markets include facilitating retail competition by enabling retailers to sell natural gas to residential and business customers.

This is achieved by setting out provisions for registering as a retail market participant, procedures for the transfer of customers between retailers, as well as processes in relation to the retailer of last resort scheme, metering, and in states other than Victoria, arrangements for gas allocation, settlement, balancing and processes to deal with unaccounted for gas.

Relevant provisions

NGL: Chapter 2 (Part 7).

NGR: Parts 15A and 15B.

Jurisdictional application

Currently in operation in New South Wales, the Australian Capital Territory, Queensland, South Australia and Victoria supplied by distribution systems.

Note: In Western Australia, AEMO also administers the Retail Market Scheme under the Energy Coordination Act 1994 (WA) for the gas retail market in Western Australia.

6.2 Issues for consultation

The Commission has identified a number of potential issues in the regulatory framework for regulated retail markets in relation to the integration of natural gas equivalents. These have been separated into two categories for discussion below:

- initial issues that may need to be dealt with as part of this review
- other potential issues that could be assessed in the future.

6.2.1 Initial identified issues in the regulated retail markets regulatory framework

The Commission has identified that the registration provisions of the NGR as it relates to retail markets may need to be amended to accommodate natural gas equivalents in the retail markets. In addition, the Commission has identified three key areas of the retail market arrangements under the RMP that may need to change to accommodate natural gas equivalents. These issues will be explored by AEMO in its review of retail market procedures.

Registration categories for the regulated retail markets

Registration categories may need to be amended to capture new types of retail market participants.[57] The NGL and NGR together identify who must register with AEMO for the RMP. Consideration would need to be given to the need for new registered participant categories in these markets, to accommodate constituent gas producers or facility operators who supply

57 Under s. 91LB of the NGL participants under the regulated retail market currently include service providers, users, non-scheme pipelines users, producers, storage providers, traders and a class prescribed under the regulations.

the constituent gases to create a natural gas equivalent. This may depend on how injections of constituent gases to create the natural gas equivalent are accounted for in settlement and who is responsible for providing injection information to AEMO. If constituent gas producers or facility operators are required to participate in retail markets, then changes would be required to:

- the regulations made under the NGL to prescribe additional classes of retail market participants
- the retail market participant provisions of the NGR, to specify constituent gas producers or facility operators as new registrable capacities for each relevant retail market.

Settlement

The settlement and balancing arrangements will need to be amended to accommodate the injection of constituent gases at a distribution level.

The injection of constituent gases into distribution systems has the potential to distort settlement in the RMP. The market rules and procedures need to be reviewed to:

- ensure the constituent gas injections are taken into account when determining the allocation and settlement of natural gas between users in the relevant network
- provide a mechanism for allocating constituent gas injections to market participants and for those injections to be allocated to users in the relevant network section and balanced against withdrawals.

Metering

The metering arrangements will need to be amended to ensure consumers are charged correctly. At a minimum this is likely to require:

- that existing gas chromatographs be tested and, if required, recalibrated, modified or replaced, to ensure they can measure the heating value of natural gas equivalents throughout the distribution systems
- changes to the metering requirements in relevant jurisdictional instruments to ensure that gas monitoring systems on distribution systems can accurately measure the energy content of natural gas equivalents at different times and locations
- local heating values to be determined for specific parts of the system and calculated more often than under current arrangements.

Clarification of who is responsible for the natural gas equivalent

The introduction of natural gas equivalents into distribution systems also raises whether distributors or retailers are responsible for creating the natural gas equivalent and if this is to be accounted for in the regulatory framework, or in gas transportation contracts.

Matters identified by AEMO

This review will also address any issues for the NGR and NERR that AEMO identifies in the course of its review of its procedures and other subordinate instruments that are required to ensure the regulated retail markets operate as intended.

QUESTION 18: INITIAL IDENTIFIED ISSUES IN THE REGULATED RETAIL MARKETS

1. Are changes to the retail market registration provisions required to accommodate natural gas equivalents?

2. Are there any other changes required to the retail market provisions in the NGR to accommodate natural gas equivalents?

6.2.2 Other potential issues in the retail market

Several other aspects of gas retail markets may need to change to accommodate natural gas equivalents. However, the Commission's preliminary view is that these issues are not a high priority for this review and could instead be assessed in the future. These issues are set out below.

Treatment of the cost of the constituent gases

In the initial phase of development of projects creating natural gas equivalents, the extent to which the cost of the constituent gases is different to the wholesale component of natural gas supply is not likely to be material. In the early phases of market development, most projects are likely only to be injecting constituent gases into distribution systems to the level required to offset UAFG, in the order of 2.5 to 5 per cent for non daily metered customers.

As constituent gases increase proportionally as a share of the overall gas stream in the future, the issue of the cost of producing the constituent gases and how this is passed through to customers will become more important to consider within market frameworks and the retail market design.

Cost recovery and information on the cost of gas

The NERL and NERR set minimum requirements for energy contracts, including both standard and market retail contracts.[58] These include billing, payment obligations, pricing and customer complaints and dispute resolution. This framework does not require the bill to specify the final price of gas delivered nor does it require a bill to specify what each component of the price should be. For example, what benchmark the wholesale component of gas costs should make reference to.

A number of retailers competing in each part of the distribution system provides the competitive pressure to maintain pricing at cost reflective levels. However, if a natural gas equivalent is only introduced to a single gas distribution system implications for competition may arise.

The introduction of natural gas equivalents that have a higher blend of constituent gases with natural gas will see an increasing need to address the process by which the cost of natural gas equivalents are recovered from consumers, and the implications for the market of having

58 https://www.aemc.gov.au/regulation/energy-rules/national-energy-retail-rules/regulation

limited suppliers of constituent gases in any one distribution system. A number of issues may need to be considered:

- Consumer choice

  If a consumer's connection is to a distribution system that is supplying a natural gas equivalent and renewable gas targets are not yet mandated, does the consumer have a choice to opt out of purchasing the natural gas equivalent. If some consumers opt out, what does this mean for consumers who do not opt out of a natural gas equivalent.

- Competition

  How is competition between retailers maintained within a distribution system with natural gas equivalents or a higher blend of constituent gases.

- Mandated renewable or green gas targets at jurisdiction level

  The structure of jurisdictional targets is likely to have a bearing on retail market design, for example:

  - what obligations are placed on distributors and retailers
  - how will competition emerge in meeting these targets
  - whether the geographical application of the target is to a distribution system, across a whole jurisdiction, or broader
  - the size and timing of the target.

- Valuing the renewable component

  How is a value or cost established for constituent gas where physical gas streams cannot co-mingle or substitute for one another and where cost structures may be quite different between projects.

These issues have been highlighted to draw stakeholder attention to the potential need for work on market design in the future and to seek feedback on whether there are any issues associated with the different value, price or cost that might be put on the constituent gases forming part of natural gas equivalents, that should be considered in the course of this review.

The Commission notes that where targets are being considered, the design and application of these targets should consider the impact on competition, the choices open to consumers and the likely impact on the end user cost paid by consumers. Depending on how targets are designed and applied, changes may be needed to retail market frameworks.

QUESTION 19: OTHER POTENTIAL ISSUES IN THE REGULATED RETAIL MARKETS

1. Are there any issues the AEMC should consider in relation to the recovery of the cost of the renewable component of the natural gas equivalent from retail customers, for a natural gas equivalent?

2. Are there any issues the AEMC should consider in relation to retail competition and consumer choice as a consequence of the introduction of natural gas equivalents?
3. How are these issues impacted by jurisdictional policies in relation to mandated renewable gas targets or mandated green value in a gas stream? Are any changes to the NGR and NERR needed, either now or in the near future, to address any concerns about competition, consumer choice and cost pass through of renewables in the retail market.

7 CONSUMER PROTECTIONS

The NERL and NERR establish a national framework for the provision of a range of energy-specific consumer protections to customers.[59] The consumer protections under the NERL and NERR that relate to the sale and supply of natural gas are complemented by Part 12A of the NGR which relates to gas connections for retail customers and Part 21 of the NGR which relates to retail support obligations between distributors and retailers (together the national gas consumer protection framework).

This chapter sets out:

- an overview of the national gas consumer protections framework
- issues for consultation, which include:
  - the difference in the physical properties of natural gas equivalents compared to natural gas
  - the difference in the price of natural gas equivalents compared to the price of natural gas
  - the increased risk that customers could be supplied with gas that is unsuitable for use in their appliances if they are supplied with natural gas equivalents instead of natural gas.

7.1 Overview of consumer protections in the national gas regulatory framework

The national gas consumer protection framework is focused on the protection of residential and small business energy customers and is intended to work in conjunction with general consumer protections provided under the Australian Consumer Law. Fair trading legislation in states and territories and a range of voluntary regulation arrangements also provide some additional protections to consumers.

The energy-specific consumer protections recognise:

- the importance of energy to the health, safety and well-being of communities
- the need to protect vulnerable customers or those experiencing financial hardship
- the need to manage the impacts of power imbalances between consumers and suppliers (e.g., information asymmetry) which may enable suppliers to exploit customers.[60]

A high-level overview of the framework is provided in Box 7 below.

59 The NERL and NERR apply to the sale and supply of natural gas and electricity. This chapter focuses on the consumer protections as they apply to the sale and supply of natural gas.

60 Decker, C., *Consumer protection frameworks for new energy products and services and the traditional sale of energy in Australia*: *Final Report for the Australian Energy Market Commission,* 19 March 2020, p. 1.

BOX 7: POLICY OBJECTIVE, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objective

The NERL and NERR establish a specific consumer protection framework for the sale and supply of energy (electricity and natural gas) to small customers, a framework for retailer authorisations by the AER and a retailer of last resort scheme.

Part 12A of the NGR provides a framework for gas connections for all retail customers.

Part 21 of the NGR relates to retail support obligations including payment of distribution service charges by retailers and provision of credit support by retailers to distributors.

Provisions in the regulatory framework

NERL: All chapters.

NERR: All parts.

NGR: Part 12A (Gas connections for retail customers), Part 21 (Retail support obligations between distributors and retailers)

Jurisdictional application

The NERL and NERR have been adopted in the Australian Capital Territory, New South Wales, South Australia and Queensland[1] and Parts 12A and 21 of the NGR applies in those jurisdictions.[2]

Note that in Victoria, Western Australia and Tasmania local legislation applies.[3]

Pipelines to which it applies

The NERL, NERR and Parts 12A and 21 of the NGR apply to distribution networks in the jurisdictions that apply the NERL.

Customers to which it applies

Most consumer protections under the NERL and NERR apply only to residential and small business energy customers. Parts 12A of the NGR applies to retail customers.[4] Part 21 of the NGR applies to shared customers of distributors and retailers.[5]

Note: 1) The application of the national framework is modified by jurisdictions under their Acts applying the NERL. The AEMC provides a guide to the application of the NECF on its website: https://www.aemc.gov.au/regulation/energy-rules/national-energy-retail-rules/regulation. A consideration of these jurisdictional modifications is not within the scope of this review.

2) Under Chapter 10, Part 13 of the NGL.

3) The Northern Territory's gas reticulation and retail sale sectors are very small and there is no specific regulation of the retail sale and supply of natural gas in the Northern Territory. The *Dangerous Goods Regulations 1985* made under the *Dangerous Goods Act 1998* (NT) regulate gas works, gas installations (including meters) and appliances and gas fitters. The NERL also applies as a law of the Commonwealth in the offshore area of each state.

4) A retail customer is a person to whom natural gas is sold for premises by a retailer (s. 3 of the NGL).

5) Defined in s. 2 of the NERL as, in relation to a distributor and a retailer, a person who is a customer of the retailer and whose premises are connected to the distributor's distribution system.

The key categories of protections provided under the national consumer protection framework are:

- protections against unfair contract terms through minimum contractual terms for the sale and supply of energy
- provision of pre-contractual information by retailers and marketers
- disclosure and information requirements to equip customers to make more informed decisions about their choice of retailer and energy plan (including through the AER's Energy Made Easy website)
- rights to connection[61]
- disconnection and reconnections
- protections for customers in financial difficulty
- protections for customers who rely on life support equipment
- retailer of last resort provisions to ensure that, in the event of a retailer failure, customers can continue to be supplied with energy.

In addition, the NERL provides for energy retailers to be authorised by the AER and creates a framework for the AER to undertake retail market performance reporting.

The key elements of the NERL, NERR and Parts 12A and 21 of the NGR and the policy intent of those elements are described in more detail in appendix B.6.

7.2 Issues for consultation

'Energy' is currently defined under the NERL to mean electricity and natural gas, with natural gas having the same meaning as in the NGL. As noted in appendix A, Energy Ministers are currently considering extending the national gas regulatory framework to natural gas equivalents and constituent gases. This extension would result in natural gas equivalents falling within the definition of natural gas under the NGL, and therefore the definition of energy under the NERL. The effect of this would be that:

- the existing consumer protections under the NERL and NERR would apply to the sale and supply of natural gas equivalents to customers
- the contract between a retailer and small customers would apply to the sale of a natural gas equivalent as if it was natural gas
- the contract between a distributor and a customer would apply to the supply of a natural gas equivalent as if it was natural gas
- retailers with existing retailer authorisations from the AER to sell natural gas would be authorised to sell natural gas equivalents and retailers wishing to sell the natural gas equivalent to customers would require a retailer authorisation (or an exemption from the AER)
- the retailer of last resort scheme would apply to natural gas equivalents

61 Including by defining the rights and obligations of distributors and connection applicants in the connection process under Part 12A of the NGR, e.g. requirements for regulator-approved model terms for basic and standard connections, specified criteria for connection charges, a defined process for connection applications and a dispute resolution mechanism process.

- the gas connections framework for retail customers would apply to the connection of retail customers to distribution networks supplying natural gas equivalents
- the retail support obligations between distributors and retailers will apply in respect of customers of retailers connected to distribution networks supplying a natural gas equivalent.

This section explores whether customers being sold and supplied with a natural gas equivalent require additional protections to the protections provided to customers supplied with (unblended) natural gas.

In considering the application of the national energy consumer protection framework to the sale and supply of natural gas equivalents to customers, the Commission has considered whether potential issues in the framework may arise from:

- the difference in the physical properties of natural gas equivalents compared to natural gas
- the difference in the price of natural gas equivalents compared to the price of natural gas
- the increased risk that customers could be supplied with gas that is unsuitable for use in their appliances if they are supplied with natural gas equivalents instead of natural gas.

7.2.1 Physical properties of natural gas equivalents compared to natural gas

The physical properties of natural gas equivalents and natural gas may differ in several respects.[62] From a consumer perspective, the difference in energy density (the calorific or heating value) is perhaps the most important[63] and the energy density of natural gas equivalents may be higher or lower than natural gas.[64] This means that greater or lesser volumes of the natural gas equivalent may need to be supplied to a customer's premises to deliver the same heating value as natural gas.[65] Following the transition to a natural gas equivalent at their premises,[66] a customer will continue to be billed based on the energy content of the gas supplied to their premises although their bill may indicate an increase or decrease in the metered consumption (volume) of gas that is related to the supply of the natural gas equivalent rather than a change in the consumption pattern of the customer.[67]

62 See appendix E.2 of appendix E metering and technical requirements for an explanation of the technical challenges in introducing natural gas equivalents into existing gas infrastructure, including impacts on heating values.

63 As noted in previously, this review assumes that natural gas equivalents will not be supplied to customers unless it is safe for use in existing appliances and processes.

64 For example, the heating value of hydrogen is lower than that of natural gas. GPA Engineering estimated that higher heating value of a 10% hydrogen blend would be around 6.8% lower than natural gas (If differences in lean and rich natural gases are considered, GPA Engineering estimates that the difference in heating value would range between 6% and 8%): GPA Engineering, *Hydrogen in the Gas Distribution Networks – A kickstart project as an input into the development of a National Hydrogen Strategy for Australia*, 2019, p. 42. However, other constituent gases may have a higher heating value than natural gas.

65 Heating value is a key component in the calculation of consumed energy. Metered gas volumes are turned into a measure of consumed energy (in megajoules) by multiplying the volume of gas used by a pressure factor and a heating value. It is assumed for the purposes of this chapter that the consumed energy calculated for customers supplied with a natural gas equivalent will be accurate as (1) existing meters at a customer's premise will be able to accurately measure the volume of gas supplied to a customer and (2) any adjustments to gas chromatographs on distribution systems required to enable the accurate measurement of the heating value of natural gas equivalents will be made.

66 Because the supply of the natural gas equivalent by the relevant distribution system or part of the distribution system has been approved.

67 Note: billing is calculated on MJ consumed and not on volume of gas

Given the potential for the supply of natural gas equivalents to result in changes to the volume of gas supplied to a customer's premises that are unrelated to changes in the consumption pattern of the relevant customer, there are a number of potential changes to the national consumer protection framework:

- a new requirement for retailers to notify existing customers prior to the transition from the supply of natural gas to a natural gas equivalent (or on the first bill after the transition) that:
  - the customer is now being supplied with the natural gas equivalent
  - the changes the customer may see in relation to the quantity of gas metered at their premises following the transition (and the reason for that change).[68]
- a change to the model terms and conditions for standard retail contracts and the minimum requirements for market retail contracts to make clear if the supply of gas under that contract is a supply of natural gas or a natural gas equivalent.
- a new requirement for retailers who receive requests for historical billing data from a customer to state in the billing information provided if there was a transition from natural gas to a natural gas equivalent during the billing history period for which information is requested, and the date at which the transition occurred.
- if the natural gas equivalent to be supplied has a different heating value from natural gas, a requirement for retailers to issue a bill based on an actual meter read for customers with accumulation (non-interval meters) before supply is transitioned to a natural gas equivalent.

7.2.2 The price of natural gas equivalents compared to the price of natural gas

A retailer may wish to increase the prices it charges to customers connected to a distribution system that has transitioned to supply a natural gas equivalent because the constituent gas has a higher cost gas than natural gas.

The NERL and NERR impose obligations on retailers regarding variations to standing offer prices and tariffs payable under market retail contracts:

- a retailer may only vary standing offer prices once in a six-month period and must publish variations to its standing offer prices in a newspaper and on its website at least 10 business days before the new prices apply and inform each affected customer of the variation when the retailer sends the next bill to the customer[69]
- a retailer must give notice to the customer of any variation to the tariffs and charges that affects the customer under a market retail contract at least five business days before the variation applies.[70]

These provisions raise the issue of whether retailers that are changing prices because of the transition to the supply of a natural gas equivalent should be required to disclose this as a

68 Alternatively, a new requirement could be imposed on the relevant distributor to publish a fact sheet that provides information to customers in a distribution system transitioning to a natural gas equivalent on the changes customers may see in the volume of gas supplied to their premises.

69 Section 23 of the NERL: Model terms for standing offer prices.

70 Rule 46 of the NERR.

reason for a variation to its standing offer prices and/or market retail prices at the time the relevant price changes are notified.

7.2.3 Responsibility for quality of natural gas equivalents and compensation for defective gas supply

One of the issues that arises in accommodating natural gas equivalents in the national gas consumer protection framework is the responsibility for the quality of the natural gas equivalent and the potential impact of gas quality on customer appliances. This issue arises because:

- the quality of the gas stream may be more variable than it is currently because natural gas equivalents may be made up of a blend of natural gas and other gases or gases other than natural gas. In the case of blends, only blends of specified proportions of a constituent gas (such as hydrogen) and natural gas may be natural gas equivalents.[71]
- the quality of the gas stream may be more directly under the control of distributors or retailers in a particular distribution system compared to current arrangements because, for example, distributors may manage facilities for creating blends of natural gas and constituent gases to produce a natural gas equivalent.

Further consideration is needed regarding whether the existing allocation of risk for gas quality and protections for consumers under the national gas regulatory framework are appropriate when the framework is extended to natural gas equivalents.

BOX 8: OVERVIEW OF THE CURRENT CONSUMER PROTECTIONS FRAMEWORK

Under section 316(1) of the NERL, retailers and distributors are given immunity for any partial or total failure to supply energy unless in bad faith or through negligence. This failure to supply energy includes supply of 'defective energy'. The term 'defective energy' is likely to encompass the supply of energy that is not suitable for consumption.

This immunity is reflected in the deemed standard connection contract between distributors and customers under the NERR. Under the deemed standard connection contract, a distributor, to the extent permitted by law, gives no condition, warranty or undertaking, and makes no representation about the condition or suitability of energy, including its quality, fitness for purpose or safety, other than as set out in the contract.[1] The immunity under section 316(1) of the NERL is also referenced in the deemed standard connection contract in the NERR.[2]

Under the NERL, distributors and retailers can also vary or exclude the operation of section 316(1) in agreements with a person other than a small customer.[3] Through their application acts, South Australia and NSW have permitted distributors to limit their liability to small customers for negligence as provided in their local regulations. For example, in NSW, the deemed standard connection agreement limits liability for failures to supply energy that is not

71 Higher level blends may be other gas products because they are not suitable for use in customer appliances.

already excluded under the contract or the NERL to the lesser of the cost of repair or replacement of any property damaged as a result of the failure, or $5,000.

The small compensation claims regime under the NERL has not been adopted by any jurisdiction. If it were adopted by a jurisdiction, it should be possible for the national Regulations or local legislation to specify an 'off spec' supply of the natural gas equivalent to be a claimable incident. The regime does not involve having to establish fault, negligence or bad faith on the part of a distributor in order to receive compensation from the distributor under the regime.

Note: 1) Clause 8(b), Schedule 2 of the NERR.
2) Clause 8(c), Schedule 2 of the NERR.
3) Section 316(2) of the NERL.

There are likely to be different regulatory options to protect customers from loss caused by 'off spec' natural gas equivalents if this is considered necessary. A combination of NERL, NERR, national regulations and jurisdictional changes may be required. For example:

- changes to the scope of immunity in the NERL and/or clarification that defective supply in the context of the natural gas equivalent includes supplying a gas that exceeds the relevant blend limit for the natural gas equivalent
- changes to jurisdictional limits on distributor's liability for negligence for defective supply of energy
- changes to the NERR deemed standard connection contract to reflect changes to the NERL immunity
- jurisdictional adoption of the small compensation claims regime and specifying the supply of 'off spec' natural gas equivalents to be a claimable incident or changes to jurisdictional guaranteed service level schemes to enable customers to access compensation for damage caused by 'off spec' blends. If specified as a service level in a jurisdiction's guaranteed service level scheme, the requirement to make a payment to the customer for failure to meet the service level can be enforced under the deemed standard connection contract.[72]

QUESTION 20: CONSUMER PROTECTION FRAMEWORK

1. Do you consider that changes are required to the consumer protection framework to reflect the physical properties of natural gas equivalents compared to natural gas? Specifically:
    a. Should retailers be required to notify existing customers prior to the transition from the supply of natural gas to a natural gas equivalent that the customer is now being

72 Clause 5.4, Schedule 2 of the NERR.

supplied with the natural gas equivalent and the changes the customer may see in relation to the quantity of gas metered at their premises following the transition?

  b. Should the model terms and conditions for standard retail contracts and the minimum requirements for market retail contracts be amended to make clear if the supply of gas under that contract is a supply of natural gas or a natural gas equivalent?
  c. Should retailers who receive requests for historical billing data from a customer be required to state in the billing information provided if there was a transition from natural gas to a natural gas equivalent during the billing history period for which information is requested, and the date at which the transition occurred?
  d. If the natural gas equivalent to be supplied has a different heating value from natural gas, should there be a requirement for retailers to issue a bill based on an actual meter read for customers with accumulation (non-interval) meters before supply is transitioned to a natural gas equivalent?
2. Are there any other gaps in the consumer protection framework that arise because of the difference in the physical properties of natural gas and natural gas equivalents?
3. Do you consider that customers should be informed if price variations occur because of the transition to natural gas equivalents?
4. How should the risks of 'off spec' natural gas equivalents be allocated under the NERL and NERR? Is the existing allocation of risk for the quality of natural gas appropriate if distributors have responsibility for creating the natural gas equivalent (for example, through the operation of blending facilities)? What is the appropriate mechanism for managing loss suffered by customers as a result of 'off spec' natural gas equivalents?

8 REGULATORY SANDBOX FRAMEWORK

A regulatory sandbox is a framework within which market participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.

This chapter sets out:

- an overview of the regulatory sandbox framework
- issues for consultation, which include:
  - issues arising from extending the regulatory sandbox framework to natural gas equivalents and constituent gases
  - issues arising from extending the regulatory sandbox framework to other gas products.

8.1 Overview of the regulatory sandbox framework

In October 2018, the AEMC was requested to provide advice to the COAG Energy Council on how to best facilitate coordination of proof-of-concept trials and the need for formal regulatory sandbox arrangements to support innovative projects offering benefits to customers while managing any risks.[73]

On 22 November 2019, the COAG Energy Council agreed to the recommendations to introduce a regulatory sandbox toolkit that would enable energy market participants to trial innovative concepts in the market at a smaller scale, on a time-limited basis and with appropriate safeguards in place.[74] Following public consultation on the proposed amendments to the national energy laws and rules to give effect to the regulatory sandbox arrangements, a bill to amend the National Electricity Law, NGL and NERL was introduced into the South Australian House of Assembly on 25 August 2021.[75] The bill, if passed by the South Australian Parliament, will empower the South Australian Minister for Energy to make National Electricity Rules, NGR and NERR in relation to a regulatory sandbox framework.

A high-level overview of the national gas regulatory sandbox framework as it applied to natural gas is provided in Box 9 below.

BOX 9: POLICY OBJECTIVE, PROVISIONS AND JURISDICTIONAL APPLICATION

Policy objective

The objective of the regulatory sandbox framework is to enable energy market participants to

73 Following the recommendations provided in the Independent Review into the Future Security of the National Electricity Market (Finkel Review), the AEMC was requested by the Senior Committee of Officials to provide interim advice by February 2019 as part of the Electricity network economic regulatory framework review.

74 The COAG Energy Council agreed to the recommendations based on AEMC, *Regulatory sandbox arrangements to support proof-of-concept trials*, final report, 26 September 2019. See https://www.aemc.gov.au/market-reviews-advice/regulatory-sandboxes.

75 Statutes Amendment (National Energy Laws) (Regulatory Sandboxing) Bill 2021.

trial innovative concepts in the market at a smaller scale, on a time-limited basis and with appropriate safeguards in place.

Proposed provisions in national gas regulatory framework

NGL: Chapter 1 — Parts 1, 3; Chapter 2 — Parts 1-2; and Chapter 9 — Parts 1-3.

NGR: Part 15E.

NERL: Parts 1, 5A, 8 and 10. NERR: Part 13

Jurisdictional application

The NGL and NGR have been adopted in all jurisdictions including the Commonwealth, and Western Australia on a modified basis.

The NERL and NERR have been adopted in the Australian Capital Territory, New South Wales, South Australia and Queensland.[1]

Note that in Victoria, Western Australia and Tasmania local legislation applies.

The Northern Territory's gas reticulation and retail sale sectors are very small and there is no specific regulation of the retail sale and supply of natural gas in the Northern Territory. The *Dangerous Goods Regulations 1985* made under the *Dangerous Goods Act 1998* (NT) regulate gas works, gas installations (including meters) and appliances and gas fitters. The NERL also applies as a law of the Commonwealth in the offshore area of each state.

Note: 1) The application of the national framework is modified by jurisdictions under their Acts applying the NERL. The AEMC provides a guide to the application of the NECF on its website: https://www.aemc.gov.au/regulation/energy-rules/national-energy-retail-rules/regulation. A consideration of these jurisdictional modifications is not within the scope of this review.

Once passed through the South Australian Parliament, the NGL and NERL will include the key aspects of the regulatory sandbox framework as it applies to natural gas, including:

- Introducing the concept of a trial project. The definition of trial project is central to the regulatory sandbox framework as it defines the scope of the functions conferred on the AER and the AEMC to facilitate proof of concept trials. A trial project will be defined under the NGL and NERL as a project that:
  - the AER or AEMC (as the case may be) is satisfied is genuinely innovative, considering the innovative trial principles specified in the NGL and NERL
  - tests an approach in relation to natural gas services (under the NGL) or customer connection services or customer retail services (under the NERL)
- Providing the AER with power to make trial waivers that can provide time-limited regulatory relief to trial projects. The AER will be able to grant trial waivers if a trial project requires an exemption from a specific rule or from the participant registration requirements.
- Providing the AEMC with power to make rules specific to trial projects (trial rules) under an amended rule change process. The rule change process can be used if an eligible trial project requires new rules or alteration of existing rules for a limited time.

- Extending the AER's functions and powers to monitor the conduct and outcomes of trial projects and investigate breaches of the laws, regulations and rules and the trial waiver and trial rule.[76]

The supporting provisions in the NGR and NERR provide for:

- the contents of trial projects guidelines to be made by the AER
- requirements for how explicit informed consent may be given by retail customers participating in trial projects
- the granting of trial waivers by the AER to enable trial projects to be carried out, including the form and content of applications for trial waivers, consultation on trial waivers and the matters the AER must have regard to in deciding on trial waivers (eligibility requirements)
- the information that is required to be provided to the AEMC in an application for the making of a trial rule
- early termination and opt-out and termination provisions which require the trial projects guidelines to provide for processes by which and grounds upon which:
  - retail customers participating in a trial project may apply to the AER to opt out of a trial project
  - the AER may terminate a trial waiver or recommend the AEMC repeal a trial rule
  - a person to whom a trial waiver is granted must allow a retail customer to opt out of a trial project.

The key elements of the regulatory sandbox framework as it will apply to natural gas and the policy intent of those elements are described in more detail in appendix B.7.

8.2 Issues for consultation

8.2.1 Issues arising from extending the regulatory sandbox framework to natural gas equivalents and constituent gases

If the regulatory sandbox arrangements under the NGL and NERL are extended to natural gas equivalents and constituent gases, persons or bodies that propose to undertake trial projects would be able to seek trial waivers or trial rules to test approaches in relation to the sale and supply of a natural gas equivalent to customers (a change of product trial) or to the facilities and activities relating to constituent gases that make up a natural gas equivalent. A change of product trial may give rise to a potential gap in the provisions relating to customer opt-outs under regulatory sandbox rules.[77]

As described above, under the proposed regulatory sandbox rules, the trial project guidelines made by the AER must provide for processes by which, and grounds upon which, a person to whom a trial waiver is granted must allow a retail customer to opt out of a trial project. However, where a change of product trial is to test the supply of a natural gas equivalent

76 Section 15(1)(ba) of the NEL, Section 204(1)(ba) of the NERL, Section 27(1)(ba) of the NGL.

77 Based on the consultation version of the proposed amendments to the NGR and NERR at: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Regulatory%20Sandboxing%20-%20Draft%20Rules.pdf.

service, for example, it does not appear practicable for an individual retail customer to have a choice in product as there will only be the test product that will be supplied during the trial. If this is the case, the NGR and NERR may need to be amended to reflect that a retail customer cannot opt out of a change of product trial. For example:

- retail customers could be provided with specific information on change of product trials as part of the process for seeking their explicit informed consent to the trial
- the AER's powers to extend trials could be made subject to receiving consent from all customers participating in the trial, and/or
- the consultation requirements for trial waiver applications for change of product trials could be amended, for example to require the AER to consult publicly on any such trials.

8.2.2 Issues arising from extending the regulatory sandbox framework to other gas products

If the regulatory sandbox arrangements under the NGL and NERL were extended to other gas products, market participants would be able to seek trial waivers or request trial rules to test approaches in relation to the sale and supply of the other gas product to customers. The trial sale and supply of an 'other gas product' would be a change of product trial that would give rise to the same issues under the regulatory sandbox rules as described above in the context of the natural gas equivalent products.

In addition, if the NGL and NERL allow for the trial sale and supply of an 'other gas product', then the regulatory sandbox rules could be amended to impose more stringent requirements in relation to the assessment of the safety, security and reliability impact of a trial project before trial waivers or trial rules are made. For example, in a change of product trial involving an 'other gas product', the requirements under the NGR and NERR that the AER consider the safety, security and reliability impacts of a trial waiver before making its decision on a trial waiver[78] could be supplemented with a requirement that approval from the relevant jurisdictional technical regulator is a pre-condition to the grant of a trial waiver for a change of product trial. The proponent of a change of product trial could also be required to provide the approval of the relevant jurisdictional technical regulator as part of its application to the AEMC for a trial rule.

QUESTION 21: REGULATORY SANDBOX ARRANGEMENTS

1. Is it practicable for a retail customer to opt out of a change of product trial? If not:
    a. should the definition of explicit informed consent be required to provide information that the customer is unable to opt out of the trial for the period of the trial?
    b. should the AER have power to extend a change of fuel trial if retail customers cannot practicably opt out of the trial?

78 Rule 135MC of the NGR; rule 178 of the NERR.

2. Are any changes to the consultation requirements regarding proposed trial waivers for change of product trials needed? For example, on the AER public consultation requirements for change of product trials.
3. Should amendments be made to specify certain pre-conditions to the granting of a trial waiver for a change of product trial involving the sale and supply of an 'other gas product'? If so:
   a. should the applicant be required to provide this approval as part of its application for a trial waiver?
   b. should the rule change proponent for a trial rule be required to provide this approval as part of its request for the rule?
4. Are there any other gaps that would arise in the proposed regulatory sandbox framework if it is extended to natural gas equivalents, other gas products and constituent gases?

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity
AMDQ cc	Authorised Maximum Daily Quantity Credit Certificates
ARENA	Australian Renewable Energy Agency
authorised MDQ	authorised maximum daily quantity
BB	Bulletin Board
BoD	Beginning of day
Commission	See AEMC
CTP	Capacity trading platform
DAA	Day ahead auction
DDS	Declared Distribution System
DTS	Declared Transmission System
DTS SP	Declared Transmission System service provider
DWGM	Declared wholesale gas market
ERA	Economic Regulation Authority
ESC	Essential Services Commission
GDSC	Gas Distribution System Code
GRCF	Gas Retail Consultative Forum
GSH	Gas supply hub
GSOO	Gas Statement of Opportunities
MCE	Ministerial Council on Energy
MJ	Megajoule
MJ/h	Megajoule-hour
MOS	Market operator services
MSVs	Market schedule variations
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National gas objective
NGR	National Gas Rules

RMP	Retail Market Procedures
STTM	Short term trading market
TJ	Terajoule
UAFG	Unaccounted for gas
VGPR	Victorian Gas Planning Report

A OVERVIEW OF THE REGULATORY FRAMEWORKS REVIEW

This appendix provides additional detail on:

- the approach established by the Energy Ministers to review the regulatory frameworks
- the broader review framework — including what is in and out of scope of the AEMC review
- governance of the reviews.

A.1 Approach to reviewing the regulatory frameworks

In undertaking this review, the AEMC has had regard to the officials' proposed approach to extending the "national gas regulatory framework" to natural gas equivalents and constituent gases and other gas products. The proposed approach can be summarised as follows:[79]

1. Provisions in the NGL and NERL that currently apply to natural gas and its related facilities and activities will be extended to apply to natural gas equivalents and their related facilities and activities.[80] The policy intention is that all elements of the national gas regulatory framework will apply to natural gas equivalents and their related facilities and activities in the same way it currently applies to natural gas.
2. The NGL[81] will be extended to apply to constituent gases (that is, the principal gases used in the creation of a blend other than natural gas)[82] and related facilities and activities. The policy intention is that pipelines involved in the haulage of constituent gases would be subject to economic regulation under the NGL and NGR and that other elements of the national gas regulatory framework will only be applied if the NGR and other instruments are amended.[83]
3. The AEMC, AEMO and AER's functions and powers will be extended:
    a. in the NGL and NERL to natural gas equivalents and related facilities and activities
    b. in the NGL to constituent gases and related facilities and activities.

    These amendments will enable the AEMC to make rules in relation to natural gas equivalents, their constituent gases and related facilities and activities.

The official's consultation paper notes these amendments are expected to be made in a way that, where relevant, flows through to the rules, regulations, procedures and other

79 Jurisdictional officials, Extending the national gas regulatory framework to hydrogen blends and renewable gases, information sheet, 23 September 2021 at https://energyministers.gov.au/publications/extending-national-gas-regulatory-framework-hydrogen-blends-and-renewable-gases.

80 The expression "related facilities and activities" is used to refer to facilities and activities from exploration and production through to retail supply

81 The NERL does not need to be extended to constituent gases because it focuses on the gas that is consumed, which in this case is the natural gas equivalents.

82 For example, if the natural gas equivalent is a hydrogen-natural gas blend, then the constituent gas is hydrogen.

83 For example, to extend the application of the Bulletin Board, the NGR would need to be amended to set out the additional content to be included in the GSOO relating to constituent gases.

subordinate instruments. In the case of natural gas equivalents, this is likely to involve treating these products as natural gas for the purposes of the laws, rules and procedures.

A.2 Overarching review framework and its workstreams

The AEMC's review is one workstream within the broader review framework. Each workstream's purpose is to support the Energy Ministers' goal of integrating low-level hydrogen and renewable gas blends into the national regulatory frameworks.

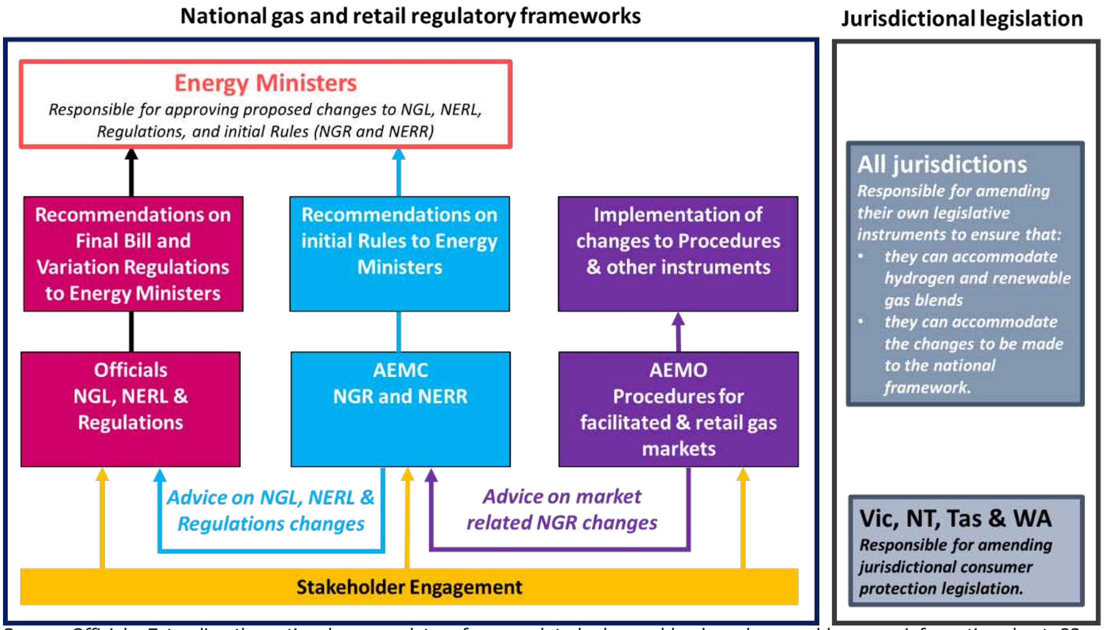
Under the approach set out by Energy Ministers the workstreams will consist of:

- Commonwealth, state and territory officials are responsible for identifying the required amendments to the NGL, NERL and regulations (the National Gas Regulations and National Energy Retail Regulations).
- The AEMC is responsible for identifying the amendments to the NGR and NERR required to accommodate natural gas equivalents.
- AEMO is responsible for identifying the amendments to its procedures and other AEMO-made instruments required to ensure settlement and metering in the facilitated and regulated retail gas markets can accommodate natural gas equivalents.

The figures below illustrate how these workstreams form part of the total review process.

In addition to amending the gas and energy retail instruments noted above, amendments will need to be made to jurisdictional legislation and regulations to accommodate natural gas equivalents and other gas products. The changes required at a jurisdictional level are not part of the AEMC's review. Rather, each jurisdiction will be responsible for amending their local legislation and regulations as necessary.

Figure A.1: Overarching review framework



Source: Officials, Extending the national gas regulatory framework to hydrogen blends and renewable gases, information sheet, 23 September 2021 at https://energyministers.gov.au/publications/extending-national-gas-regulatory-framework-hydrogen-blends-and-renewable-gases

A.2.1 Scope of the AEMC review

The figure and table below set out the scope of the AEMC's review of the NGR and NERR. It also identifies those areas that are being reviewed by jurisdictional officials and AEMO.[84] In this figure the scope of the current workstreams is indicated by blue:[85]

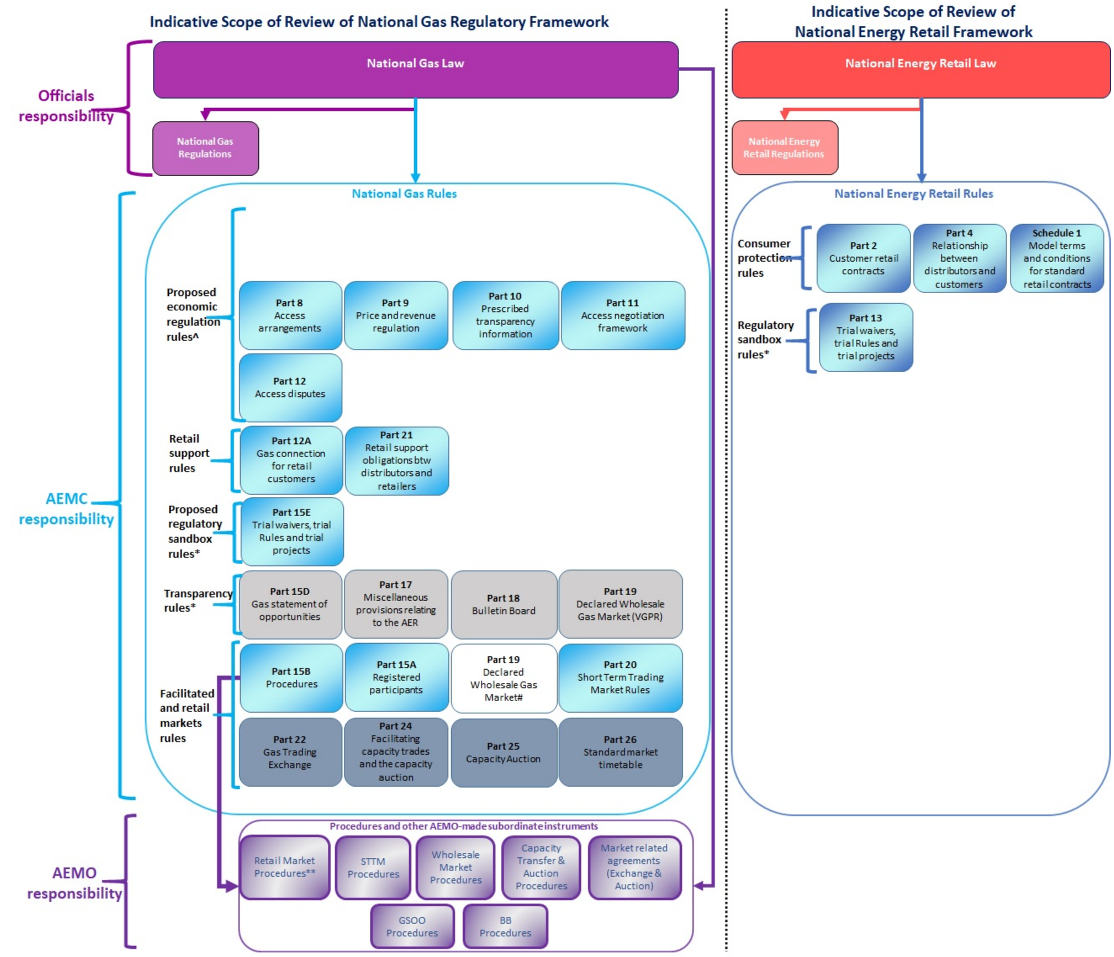
- Dark grey has been used to identify those parts of the NGR that do not appear to be a high priority to amend as part of the initial rules package from this review process because they apply at a transmission level rather than a distribution level. Potential amendments to these parts of the NGR can be considered as part of a future process.
- Light grey has been used to identify those parts of the NGR where there is a question whether they should be amended as part of the initial rules package, or deferred until a future process. This is because it is unclear whether the supply of natural gas equivalents into distribution pipelines in the early stages of the industry's development will be sufficient to require these parts of the NGR to be activated.
- White has been used to identify that part of the NGR that is the subject of the DWGM distribution connected facilities rule change process. However, some aspects of Part 19 of the NGR that may require amendment may fall outside the scope of the rule change

84 Table A.1 and Table A.2 provide further detail on what sections of the NGR and NERR are in and out of scope

85 See also Chapter 1.

process. In those instances, the specific issues will be considered under the AEMC's review.

Figure A.2: Indicative scope of the review workstreams



^ Changes to the NGL and NGR to reflect the outcome of the Pipeline Decision RIS are currently being consulted upon.
* Changes to the NGL and NERL to incorporate the regulatory sandbox provisions are currently before SA Parliament.
' Changes to the NGL to incorporate the amendments to the market transparency mechanisms are currently before SA Parliament.
The AEMC is conducting a separate DWGM rule change. While this rule change is expected to address the gaps that could arise in the wholesale market, it will not address other gaps, such as the Victorian Gas Planning Report.
** Separate Retail Market Procedures are in place in NSW/ACT, Victoria, Queensland and South Australia.

Source: Officials, Extending the national gas regulatory framework to hydrogen blends and renewable gases, information sheet, 23 September 2021 at https://energyministers.gov.au/publications/extending-national-gas-regulatory-framework-hydrogen-blends-and-renewable-gases

Table A.1: Indicative scope of the AEMC review

CHAPTER OF THIS PAPER	PART OF THE NGR OR NERR
Economic regulation of pipelines[1]	NGR, Part 5 (Ring-fencing) NGR, Part 6 (Pipeline interconnection principles)

CHAPTER OF THIS PAPER	PART OF THE NGR OR NERR
	NGR, Part 8 (Access arrangements) NGR, Part 9 (Price and revenue determinations) NGR, Part 10 (Pipeline information disclosure requirements) NGR, Part 11 (Access negotiation framework) NGR, Part 12 (Access disputes)
Market transparency mechanisms[2]	NGR, Part 15D (Gas statement of opportunities) NGR, Part 17 (Miscellaneous provisions relating to the AER) NGR, Part 18 (Bulletin board) NGR, Part 18A (Compression and storage terms and prices) NGR, Part 19 (Declared wholesale gas markets (VGPR))
Facilitated gas markets	NGR, Part 15A (Registered participants) NGR, Part 15B (Procedures) NGR, Part 19 (Declared wholesale gas market rules)[3] NGR, Part 20 (Short term trading markets rules) NGR, Part 26 (Standard market timetable)
Regulated retail markets	NGR, Part 15A (Registered participants) NGR, Part 15B (Procedures)
Consumer protections	NGR, Part 12A (Gas connection for retail customers) NGR, Part 21 (Retail support obligations between distributors and retailers) NERR, Part 2 (Customer retail contracts) NERR, Part 4 (Relationship between distributors and customers) NERR, Schedule 1 (Model terms and conditions for standard retail contracts) NERR, Schedule 2 (Model terms and conditions for deemed standard connection contracts)
Regulatory sandboxes[4]	NGR, Part 15E (Trial rules, trial waivers, and trial projects) NERR, Part 13 (Trial waivers, trial rules and trial projects)

Note: 1) These references reflect changes to the economic regulation framework agreed by Energy Ministers.
2) These references reflect changes to the market transparency mechanisms currently before SA Parliament.
3) While the AEMC is conducting a separate DWGM rule change process, some issues (such as the Victorian Gas Planning Report) will be in scope of the review.

4) These references reflect amending rules expected to be made by the SA Minister following the changes to the NGL and NERL before the SA Parliament to introduce the regulatory sandbox framework.
Separate Retail Market Procedures are in place in NSW/ACT, Victoria, Queensland and SA.

A.2.2 Out of scope of the AEMC review

The Commission has formed the preliminary view that the following parts of the NGR and NERR are either not within the scope of this review under the terms of reference, are not expected to be impacted by the proposed changes or are unlikely to be a priority for this review.

Table A.2: **Indicative out of scope of the AEMC review**

AREA	PART OF THE NGR AND NERR	REASON
Preliminary, AER information and decision making	NGR, Parts 1-3	No impact expected
Regulatory determinations and elections	NGR, Part 4 (new proposed part)	No impact expected
Prohibition against increasing charges to subsidise particular developments	NGR, Part 7 (new proposed part)	No impact expected
Classification and reclassification of pipelines	NGR, Part 13 (new proposed part)	No impact expected
Non-access dispute resolution, confidential information, service provider performance reports	NGR, Parts 15C, 16, 17	No impact expected
Gas supply hub provisions	NGR, Part 22	Outside terms of reference as this review focuses on supply into distribution systems
Capacity trading and day ahead auction provisions	NGR, Parts 24, 25	Outside terms of reference as this review focuses on supply into distribution systems
Transparency mechanisms	NGR, Parts 15D, 17, 18, 18A, 19 (VGPR)	For constituent gases at low level the priority is unclear
Preliminary, customer hardship	NERR, Parts 1, 3	No impact expected
Relationship between distributors and retailers	NERR, Part 5	No impact expected
De-energisation (or disconnection) of premises	NERR, Part 6	No impact expected

AREA	PART OF THE NGR AND NERR	REASON
Life support obligations, prepayment meters	NERR, Parts 7, 8	No impact expected
Electricity generation in the distribution system	NERR, Part 8A	Applies to electricity generator connections only
Exempt selling regime, retail market performance reports	NERR, Parts 9, 10	No impact expected
Electricity customer benchmarks	NERR Part 11	Applies to electricity residential customers only
National energy retail consultation	NERR, Part 12	No impact expected
Savings and transitionals	NERR, Part 13	No impact on existing transitional arrangements. New transitional arrangements may be identified as a result of this review

A.3 Overarching review governance

Each workstream that forms part of the broader review of the regulatory frameworks has a significant crossover with other workstreams, and all inform each other. As such, the overarching process has been designed so that each workstream can share information to enable a consistent position across each aspect.

Examples of this information sharing, and cross-body collaboration, that has been built into the process include:

- The market bodies will all be providing input to jurisdictional officials who have been charged with the legislative change required to the NGL and NERL.
- The AEMC review will provide suggested legislation changes to the officials' review, and take on board the considerations from AEMO's review regarding potential rule changes.
- AEMO will be providing input to both the AEMC and officials on any identified issues from its review of the AEMO made procedures and other subordinate instruments with regard to the rules and the laws respectively.

The AEMC review team will also be working closely with the DWGM Distribution connected facilities rule change team.

The DWGM Distribution connected facilities rule change request was submitted by the Victorian Minister for Energy, Environment and Climate Change. It seeks to amend Part 19 of the NGR to allow gas production and storage facilities connected to the declared distribution system to participate in the DWGM. If made, the rule will have implications for enabling hydrogen and renewable gas to be injected into gas distribution systems in Victoria. This complements the work of the broader national review. For this reason, the AEMC is progressing the rule change request concurrently with the review.

B REGULATORY FRAMEWORK SUPPORTING INFORMATION

This appendix is intended to provide additional information on the regulatory framework, relevant provisions and policy intent for each of the key aspects of the regulatory frameworks being considered as part of the AEMC's review.

The information is set out according to the elements of the regulatory frameworks presented in the chapters of this consultation paper:

- economic regulation of pipelines
- market transparency mechanisms
- facilitated gas markets — DWGM
- facilitated gas markets — STTM
- regulated retail markets
- consumer protections
- regulatory sandbox.

B.1 Economic regulation of pipelines

The NGL and NGR provide for the economic regulation of pipelines under a negotiate-arbitrate model. The objective of this element of the national framework is to facilitate access to natural gas pipelines and to constrain the exercise of market power by transmission and distribution pipeline service providers.

Table B.1: **Proposed economic regulatory framework**

TOPIC	PROVISIONS	POLICY INTENT OF PROVISIONS
Regulatory framework for pipelines	NGL Chapter 3 NGR Parts 4 and 13	Negotiate-arbitrate with approved reference tariffs The objective of these provisions is to set out: • the way in which pipelines can become scheme or non-scheme pipelines and the requirement for scheme

TOPIC	PROVISIONS	POLICY INTENT OF PROVISIONS
		pipelines to submit an access arrangement • the processes for obtaining scheme pipeline and greenfield incentive determinations • the process for classifying and reclassifying pipelines
General requirements for provision of pipeline services	NGL Chapter 4 NGR Parts 5-9	The objective of these provisions is to constrain exercises of market power by service providers through: • structural and operational separation requirements • a prohibition on preventing or hindering access • a prohibition on bundling of services • a requirement to comply with pipeline interconnection principles • a requirement not to cross subsidise particular developments.
Requirement to publish prescribed transparency information	NGL Chapter 4 NGR Part 10	The objective of these provisions is to enable shippers to make informed decisions about whether to seek access to a pipeline and, if so, to effectively negotiate with service providers.
Duty to negotiate in good faith & comply with negotiation framework	NGL Chapter 4 NGR Part 11	The objective of these provisions is to facilitate timely and effective negotiations between service providers and shippers.

TOPIC	PROVISIONS	POLICY INTENT OF PROVISIONS
Access dispute provisions	NGL Chapter 5 NGR Part 12	Yes - Regulatory oriented dispute mechanism The objective of these provisions is to set out the rights that service providers and shippers have to trigger an access dispute and the scope of the matters to be considered by the dispute resolution body.

Note: Based on the consultation versions of the draft bill and amending rules published by Senior Officials on 2 September 2021 at https://energyministers.gov.au/publications/energy-senior-officials-release-gas-pipeline-draft-legal-package-consultation

B.2 Market transparency mechanisms

Table B.2: **Operation of market transparency mechanisms (with proposed changes)**

TOPIC	PROVISIONS	POLICY INTENT
Bulletin Board	NGL Chapter 7 NGR Part 18	The objective of these provisions is to set out the obligations that facilities and market participants have to provide AEMO for the purposes of the Bulletin Board. These provisions are currently being amended to provide for: • information to be collected from any person with possession or control of information relating to the natural gas industry • the specification of a range of additional information to be reported on the Bulletin Board, including information on LNG export and import facilities, natural gas reserves and resources, large user demand, and transactions (for example, short-term gas sales, gas swaps and secondary trades of storage capacity).
GSOO	NGL Chapter 2 NGR Part 15D	The objective of these provisions is to set out the information to be published in the GSOO and the matters to be considered in preparing the GSOO. These provisions are currently being amended to provide for:

TOPIC	PROVISIONS	POLICY INTENT
		• information to be collected from any person with possession or control of information relating to the natural gas industry • the extension of the GSOO to the Northern Territory • a range of additional information to be included in the GSOO • AEMO to issue mandatory surveys to collect information and to publish GSOO Procedures.
VGPR	NGL Chapter 2 NGR Part 19	The objective of these provisions is to set out the information that AEMO can collect and publish in the VGPR, to facilitate planning in the DTS and to assist market participants and other persons make economically efficient investment decisions in natural gas markets.
Compression and storage terms and prices	NGL Chapter 2 NGR Part 18A	The NGL and NGR are being amended to require compression and storage service providers to publish standing terms, prices and a range of other access related information. The objective of these provisions is to facilitate negotiations between the operators of these facilities and prospective users.
AER Price reporting function	NGL Chapter 2 NGR Part 17	The NGL and NGR are currently being amended to provide for the AER to publish a range of gas price information once the ACCC's Gas Inquiry ceases (expected 2025). The objective of these provisions is to improve price transparency in the market.

Note: Information on proposed changes based on Senior officials, *Measures to improve transparency in the gas market, proposed legal package to give effect to decision regulation impact statement*, consultation paper, 19 November 2020.

Table B.3: **Transparency reporting obligations for natural gas facilities (with proposed changes)**

FACILITY OR ACTIVITY	BULLETIN BOARD (NAMEPLATE RATING >=10TJ/DAY)	GSOO	VGPR (FOR VICTORIAN FACILITIES ONLY)	COMPRESSION STORAGE TERMS AND PRICES	AER PRICE REPORTING
Production facilities	• Nameplate rating and detailed facility information • Short term capacity outlook (7 day outlook) and material intra-day changes • Medium term capacity outlook (12 months) • Nominations and forecast use of production facilities (7 days) • Actual daily production data • Facility development projects	• Annual and peak day capacity of and constraints affecting facilities • Gas production forecasts • Committed and proposed new or expanded production facilities	• Annual and monthly forecasts • Available and prospective gas supply and the source of supply • Gas supply projects.	n.a	n.a
Transmission pipelines	• Nameplate rating and detailed facility information • Short term capacity outlook (7 day outlook) and material intra-day changes •	• Annual and peak day transmission capacity and constraints (including interconnection constraints)	• Annual and monthly forecasts • Pipeline capacity • Transmission and distribution projects (including extensions and expansions)	n.a	n.a

FACILITY OR ACTIVITY	BULLETIN BOARD (NAME-PLATE RATING >=10TJ/DAY)	GSOO	VGPR (FOR VICTORIAN FACILITIES ONLY)	COMPRESSION STORAGE TERMS AND PRICES	AER PRICE RE-PORTING
	• Linepack Capacity Adequacy indicator flag • Medium term capacity outlook (12 months) • Nominations and forecast use of storage facilities (7 days) • Actual daily flow data • Uncontracted pipeline capacity and list of shippers with primary firm capacity • Facility development projects	• Committed and proposed new transmission pipelines and pipeline augmentations	• Availability of equipment, details of any constraints and proposed maintenance		
Stand alone compression facilities	• Nameplate rating and detailed facility information • Short term capacity outlook (7 day outlook) and material intra-day changes • Linepack Capacity Adequacy indicator flag •	n.a	n.a	• Standing prices and terms for each facility service • The methodology and inputs used to calculate the standing price • Information on the actual prices paid	n.a

FACILITY OR ACTIVITY	BULLETIN BOARD (NAME-PLATE RATING >=10TJ/DAY)	GSOO	VGPR (FOR VICTORIAN FACILITIES ONLY)	COMPRESSION STORAGE TERMS AND PRICES	AER PRICE RE-PORTING
	• Medium term capacity outlook (12 months) • Nominations and forecast use of facilities (7 days) • Actual daily production data • Uncontracted storage capacity and list of shippers with primary firm capacity • Facility development projects			by users and the non-price terms and conditions	
Storage facilities	• Nameplate rating and detailed facility information • Short term capacity outlook (7 day outlook) and material intra-day changes • Medium term capacity outlook (12 months) • Nominations and forecast use of storage facilities (7 days)	• Peak day capacity of and constraints on storage facilities • Committed and proposed new or expanded storage facilities	• Annual and monthly forecasts • Storage capacity • Storage operating parameters (for example, injection and withdrawal rates) • Storage projects • Availability of equipment, details of any constraints and proposed	• Standing prices and terms for each facility service • The methodology and inputs used to calculate the standing price • Information on the actual prices paid by users and the non-price terms	n.a

FACILITY OR ACTIVITY	BULLETIN BOARD (NAMEPLATE RATING >=10TJ/DAY)	GSOO	VGPR (FOR VICTORIAN FACILITIES ONLY)	COMPRESSION STORAGE TERMS AND PRICES	AER PRICE REPORTING
	• Actual daily storage data (that is, volume injected and withdrawn and actual volume of gas in storage) • Uncontracted storage capacity and list of shippers with primary firm capacity • Facility development projects.		maintenance	and conditions	
Large users or market customers	• Nameplate rating of facility • Daily consumption data	• Projected demand (annual and peak day forecasts)	• Annual and monthly forecasts • Peak daily demand for 1 in 2 peak day conditions • Anticipated material constraints on capacity of the declared distribution system and the location of such constraints if they can have a material effect on operation of the DTS	n.a	n.a
Parties to contract	• Sellers in short term gas supply agreements and	n.a	n.a	n.a	Parties specified in AER pricing order

FACILITY OR ACTIVITY	BULLETIN BOARD (NAME-PLATE RATING >=10TJ/DAY)	GSOO	VGPR (FOR VICTORIAN FACILITIES ONLY)	COMPRESSION STORAGE TERMS AND PRICES	AER PRICE RE-PORTING
	gas swaps with contract quantity of at least 1 TJ must report price and non-price terms and conditions • Sellers in secondary trades of storage and transportation capacity must report price and non-price terms and conditions				must report information on gas prices agreed to under gas supply agreements and gas swaps

B.3 Facilitated gas markets — STTM

Table B.4: **Key elements of the NGL and NGR for the STTM**

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
Fundamentals of the STTM	NGL Chapter 2 Part 6 Division 2A	The objective of the provisions under the NGL is to: • outline AEMO's functions within the STTM • define market participation • outline the requirement for registration to participate in the STTM • require that gas supplied to an STTM hub must comply with the gas quality specifications specified in the NGR for that STTM hub • describe the nature of the STTM Procedures that can be made by AEMO.

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
STTM participation	NGR Part 15A	The objective of Part 15A of the NGR in relation to the STTM is to outline the two ways that a person can participate in a registrable capacity in the STTM ('STTM shipper' and 'STTM user'), and the requirement for registration if a person participates in either of these capacities.
STTM procedures	NGR Part 15 B	The objective of Part 15B of the NGR is to outline the matters about which STTM Procedures may be made by AEMO, and the process for making Procedures.
STTM rules	NGR Part 20	The objective of Part 20 of the NGR is to regulate various aspects of the STTM including: • the STTM Hubs and STTM distribution systems • registration of trading participants • information that must be provided by STTM facilities and STTM distributors • registration of services and trading rights • market operations, including scheduling and pricing, and allocations (including ownership, risk and responsibility for gas which includes responsibility for gas quality delivered by the shipper to the hub) • market settlement and prudential requirements.

B.4 Facilitated gas markets — DWGM

Table B.5: Key elements of the NGL and NGR for the DWGM

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
Fundamentals of the DWGM	NGL Chapter 2 Part 6 Division 2	The objective of the provisions under the NGL is to outline: • AEMO's declared system functions, including the operation and administration of the DWGM • AEMO's relationship with transmission service providers and facility operators • define market participation in the DWGM

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
		• the requirement for registration to participate in the DWGM • the nature of the Wholesale Market Procedures that can be made by AEMO.
DWGM participation	NGR Part 15A	The objective of Part 15A of the NGR in relation to the DWGM is to outline the ways that a person can participate in a registrable capacity in the DWGM: • declared transmission system service provider • distributor • producer • storage provider • interconnected transmission pipeline service provider • transmission customer • distribution customer • retailer • trader. Producers, storage providers, transmission customers, distribution customers, retailers and traders can be market participants.
DWGM procedures	NGR Part 15B	The objective of Part 15B of the NGR is to outline the matters about which Wholesale Market Procedures may be made, and the process for making Procedures.
DWGM rules	NGR Part 19	The objective of Part 19 of the NGR is to regulate various aspects of the DWGM including: • market operation, including scheduling, allocation and reconciliation and settlements • technical matters, including connection to the DTS, DTS service provider obligations, gas quality standards and monitoring, metering, and procedures for dealing with UAFG • market information and system planning • intervention and market suspension

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
		• dispute resolution • enforcement and monitoring.

B.5 Regulated retail markets

Table B.6: Key elements of the NGL and NGR for regulated retail markets

TOPIC	PROVISIONS	POLICY INTENT OF THE PROVISIONS
Regulated Retail Markets	NGL Chapter2 Part 7 *National Gas (South Australia) Regulations* [1] NGR Part 15A Registered Participants NGR Part 15B Procedures	The objective of these provisions under the NGL is to regulate retail gas markets in relation to: • Defining retail gas markets and regulated retail gas markets • Retail market • The power to make retail market procedures, the nature of the procedures and compliance with procedures The objective of these provisions under the NGR is to regulate retail gas markets in relation to: • Retail market participation • Requirements for registration • Retail market procedures Other subordinate procedures — Retail Market Procedures — made by AEMO under the NGL.

Note: 1) In respect of regulated retail gas markets the SA Regulations prescribe additional classes of retail gas market participants for the SA market as swing service providers and shippers.

B.6 Consumer protections

Table B.7: **Key elements of the National Energy Customer Framework under the NERL**

<table>
<tr><th rowspan="2">TOPIC</th><th colspan="2">PROVISIONS</th><th rowspan="2">POLICY INTENT OF THE PROVISIONS</th></tr>
<tr><th>NERL (PROCEDURES UNDER NERL)</th><th>NERR</th></tr>
<tr><td>Relationship between retailers and small customers</td><td>Part 2, Divisions 1-10 Relationship between retailers and small customers

Part 4 Small customer complaints and dispute resolution</td><td>Part 2 Customer retail contracts

Part 3 Customer hardship

Part 6 De-energisation (or disconnection) of premises — small customers

Part 7 Life support equipment

Part 8 Prepayment meter systems

Schedule 1: Model terms and conditions for standard retail contracts</td><td>The objective of these provisions is to set out the obligations that retailers have in terms of:

• making offers to sell energy to small customers;
• complying with mandatory minimum terms and conditions for small customer standard and market retail contracts, including:
  ◦ requirements for billing, including the basis of customer bills, bill contents and frequency and bill disputes
  ◦ small customer access to historical billing information
  ◦ requirements for payment plans for hardship customers or other residential customers facing payment difficulties
  ◦ presentation of prepayment meter customers where applicable
•</td></tr>
</table>

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NERL (PROCEDURES UNDER NERL)	NERR	
			• obtaining explicit informed consent from customers; • marketing energy to small retail customers, including presentation of standing offer prices • having a regulator approved customer hardship policy in place • supplying customers that have life support equipment • disconnections, with the rules limiting the circumstances in which disconnection can occur and the additional protections in place for customers experiencing hardship or financial difficulty and a prohibition on disconnecting premises where life support equipment is required • having procedures to handle small customer complaints and disputes. They also set out the rights small customers have in terms of accessing a dispute resolution mechanism.
Relationship between	Part 3 Relationship between distributors and customers	Part 4 Relationship between distributors and customers	The objective of these provisions is to set out the obligations that distributors must

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NERL (PROCEDURES UNDER NERL)	NERR	
distributors, customers and retailers	Part 4 Small customer complaints and dispute resolution Part 7 Small compensation claims regime	Schedule 2: Model terms and conditions for deemed standard connection contracts	facilitate the supply of energy to retail customers, in terms of: • customer connections (existing, deemed standard and negotiated connection contracts) • meeting service standards, fault reporting and providing information on consumption or charges • notifying customers about planned and unplanned interruptions • having procedures to handle small customer complaints and disputes. They also set out the rights that small customers have in terms of seeking compensation for customer connection services and to access a dispute resolution mechanism.
		Part 5 Relationship between distributors and retailers-retail support obligations	The objective of these provisions is to set out the obligations that distributors and retailers have in relation to shared customers in terms of: • assisting and cooperating with each other in the performance of their respective obligations

<table>
<tr><th rowspan="2">TOPIC</th><th colspan="2">PROVISIONS</th><th rowspan="2">POLICY INTENT OF THE PROVISIONS</th></tr>
<tr><th>NERL (PROCEDURES UNDER NERL)</th><th>NERR</th></tr>
<tr><td></td><td></td><td></td><td>sharing information, dealing with enquiries and customer complaints
disconnections and reconnections.</td></tr>
<tr><td>Informed decision making</td><td>Part 2, Division 11 AER Retail Pricing Information Guidelines and price comparator</td><td>Part 11 AER Retail Pricing Information Guidelines and price comparator</td><td>The objective of these provisions is to enable small customers to make more informed decisions about their choice of retailer and energy plan, by:
requiring retailers to present their standing offers and market offers in a standardised manner (that is, so they can be readily compared)
providing small customers with access to a website (Energy Made Easy) that they can use to compare retailers' standing and market offers.</td></tr>
<tr><td>Authorisation of retailers</td><td>Part 5 Authorisation of retailers and exempt seller regime

(AER Retailer authorisation guidelines, AER Exempt selling guidelines)</td><td>n.a.</td><td>The objective of these provisions is to ensure that persons selling energy to customers for premises are suitably qualified by:
requiring persons selling energy to a person for premises to hold a retailer authorisation from the AER or hold an exemption from that requirement from the AER</td></tr>
</table>

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NERL (PROCEDURES UNDER NERL)	NERR	
			• setting entry criteria for persons wishing to hold a retailer authorisation • enabling the AER to set conditions on retailer authorisations relating to the satisfaction of entry criteria • empowering the AER to revoke a retailer authorisation on specified grounds, including a material failure to meet the requirements of a retailer under the NERL, NERR or other subordinate instruments.
Retailer of last resort	Part 6 Retailer of last resort scheme (Retailer of last resort Procedures)	n.a.	The objective of these provisions is to ensure that customers continue to be supplied in the event their retailer fails, is suspended by AEMO or has its retailer authorisation revoked by the AER, by automatically transferring the customers to another retailer (the retailer of last resort).
AER performance regime	Part 12 Compliance and performance, Division 2 AER performance regime (AER Performance reporting procedures and guidelines)	Part 3 Customer hardship	The objective of these provisions is to enable the AER to gather information in relation to the performance of the retail energy market and energy businesses and report annually on matters including: • energy affordability

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NERL (PROCEDURES UNDER NERL)	NERR	
			• the performance of retailers in relation to customers facing hardship • the performance of distributors in relation to distributor service standards and small compensation schemes • trends in disconnection of customers for non-payment of energy bills • compliance of energy businesses with obligations in the NERL and NERR. The AER uses the performance regime to track key customer outcomes and guide it in setting priority areas for compliance and enforcement.

Table B.8: **Key elements of the National Energy Customer Framework under the NGL**

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NGL (PROCEDURES UNDER NGL)	NGR	
Gas connection for retail customers	Chapter 10 – General (Part 13)	Part 12A Gas connection for retail customers	The objective of these provisions is to support the NECF in those jurisdictions that have adopted the NERL by: • facilitating the connection of retail customers to gas distribution

TOPIC	PROVISIONS		POLICY INTENT OF THE PROVISIONS
	NGL (PROCEDURES UNDER NGL)	NGR	
			networks through regulator approved model terms for basic and standard connections • a negotiation framework for non-standard connections • a dispute resolution mechanism customers can have recourse to.

B.7 Regulatory sandbox

Table B.9: **Policy intent of key elements of the regulatory sandbox framework**

TOPIC	PROVISIONS				POLICY INTENT OF THE PROVISIONS
	NGL	NGR	NERL	NERR	
Innovative trial principles	Section 24A	n.a.	Section 13A	n.a.	The objective of these provisions is to outline the principles that must be taken into account in determining whether a trial project is genuinely innovative in connection with granting a trial waiver or making a trial rule such as whether: • it is focused on developing new or materially improved natural gas services • it maintains adequate consumer protections. It may impact on competition in a competitive sector of a market for natural gas.
Trial waivers, trial		Part 15E		Part 13	The objective of these provisions is to make provision for:

<table>
<tr><th rowspan="2">TOPIC</th><th colspan="4">PROVISIONS</th><th rowspan="2">POLICY INTENT OF THE PROVISIONS</th></tr>
<tr><th>NGL</th><th>NGR</th><th>NERL</th><th>NERR</th></tr>
<tr><td rowspan="2">rules and trial projects</td><td></td><td>Section 135L - Purpose</td><td></td><td>Section 174 - Purpose</td><td>the granting of trial waivers by the AER to enable trial projects to be carried out
the information required to be provided to the AEMC in a request for making a trial Rule
monitoring by the AER of trial projects.
The provisions also set out the obligation to receive explicit informed consent by a retail customer to participating in a trial project in terms of:
clear and full disclosure of all matters to be provided by the person carrying out or involved in carrying out the trial project
the manner and form by which the retail customer gives consent
the requirement to create and retain a record of each consent for at least the duration of the trial waiver or trial rule
the circumstances in which consent is deemed to not be obtained by the retail customer.</td></tr>
<tr><td></td><td>Section 135M – Application for a trial waver</td><td></td><td>Section 175 – Application of trial waiver</td><td>The objective of these provisions is to set out the process for making an application for a trial waver by requiring:
applicants to apply to the AER in the form prescribed in the Trial Projects Guidelines
the application to contain information on the details of the particular provisions of the rules in respect of which the person seeks a trial waiver and identification of the trial project confidential information.
The AER may by notice in writing request the applicant provide further information by a specified date.</td></tr>
</table>

TOPIC	PROVISIONS				POLICY INTENT OF THE PROVISIONS
	NGL	NGR	NERL	NERR	
	Section 30ZD	Section 135MA – Initial consideration of a proposed trial waiver	Section 121J	Section 176 - Initial consideration of a proposed trial waiver	The objective of these provisions is to set out the AER's powers to terminate its consideration of the application if: • the AER considers the application of a trial waiver does not comply with the information requirements, or considers the proposed trial project can be carried out satisfactorily without a trial waiver, or considers the application is misconceived or lacking in substance • the applicant does not respond to a request for further information. If the AER considers it should terminate, they must: • notify the applicant in writing and provide reasons for why it has formed that view • invite the applicant to make submissions or to provide further information, and take that into account before deciding to terminate.

	Section 30Y	Section 135MB – consultation regarding a proposed trial waiver	Section 121E	Section 177 – consultation regarding a proposed trial waiver	The objective of these provisions is to set out the obligations on the AER to carry out consultation in terms of:
					• Public consultation unless satisfied the trial waiver and trial project is unlikely to:
					    • have an impact on other Registered Participants or regulated entities
					    • have a direct impact on retail customers other than those who provide consent to participate
					• Consult with AEMO in relation to any potential impact on AEMO's operation and administration of the power system, markets for natural gas or declared distribution and transmission systems, or AEMO's

<table>
<tr><th rowspan="2">TOPIC</th><th colspan="4">PROVISIONS</th><th rowspan="2">POLICY INTENT OF THE PROVISIONS</th></tr>
<tr><th>NGL</th><th>NGR</th><th>NERL</th><th>NERR</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>capacity to perform its declared system functions.</td></tr>
<tr><td></td><td></td><td>Section 135MC – Eligibility requirements</td><td></td><td>Section 178 – Eligibility requirements</td><td>The objective of these provisions is to set out the considerations the AER must have regard to in deciding to grant a trial waiver and includes:
• whether the trial project is likely to contribute to the development of regulatory and industry experience
• whether it may have an adverse effect on the safety, reliability or security of supply of energy
• whether the trial project has the potential to lead to better services and outcomes for consumers
• the extent to which, and nature of, the trial project confidential information impairs the AER's ability to provide appropriate public transparency on the conduct and outcome of the trial project.</td></tr>
<tr><td></td><td>Section 30ZB and 30ZC</td><td>Section 135MD – Extension or variation of trial waiver</td><td>Section 121H and 121I</td><td>Section 197 - Extension or variation of trial waiver</td><td>The objective of these provisions is to detail the powers the AER has to extend a trial waiver for a further specified period and to impose further conditions or modify the existing conditions of the trial waiver with the agreement of the applicant.</td></tr>
<tr><td></td><td></td><td>Section 135ME – Evidence of a trial waiver</td><td></td><td>Section 180 - Evidence of a trial waiver</td><td>The objective of these provisions is to introduce a certification scheme that will apply to the person granted the trial waiver and set out the extent and duration of the trial waiver and any conditions.
The AER must establish, maintain and publish on its website a register of all certificates issued.</td></tr>
<tr><td></td><td>Section</td><td>Section 135N</td><td>Section</td><td>Section 181 -</td><td>The objective of these provisions is to set out the information that must</td></tr>
</table>

TOPIC	PROVISIONS				POLICY INTENT OF THE PROVISIONS
	NGL	NGR	NERL	NERR	
	301	– Request for a trial Rule	249	Request for a trial Rule	be contained in a request to make a trial rule and includes the following: • detailed outline of the proposed project and explanation of how it will or is likely to lead to the achievement of the NGO and NERO • explanation of expected benefits and costs of the trial project to consumers and other market participants • explanation of why the trial rule is needed in order to conduct the trial project • the applicant's approach to consumer engagement, dispute management and evidence of operational and financial ability to carry out the trial project.
		Section 135O – Application Section 135OA – Early termination and opting out of trial projects		Section 182 – Application Section 184 - Early termination and opting out of trial projects	The objective of these provisions is to introduce processes in the Trial Projects Guidelines by which: • a retail customer participating in a trial project may apply to the AER to opt out • the AER may terminate a trial waiver or recommend to the AEMC that the AEMC revoke a trial Rule before its scheduled expiry. The AER may do so either on its own motion or upon applicant by the trial applicant, retail customer, registered participant or AEMO. A person who is granted a trial waiver must allow a retail customer to opt out of a trial project.
		n.a.	Section 121I	Section 183 – Compliance monitoring	The objective of these provisions is to set out the obligations of a person who is granted a trial waiver or applies to make a trial rule to comply with the conditions attached to the waiver or rule.

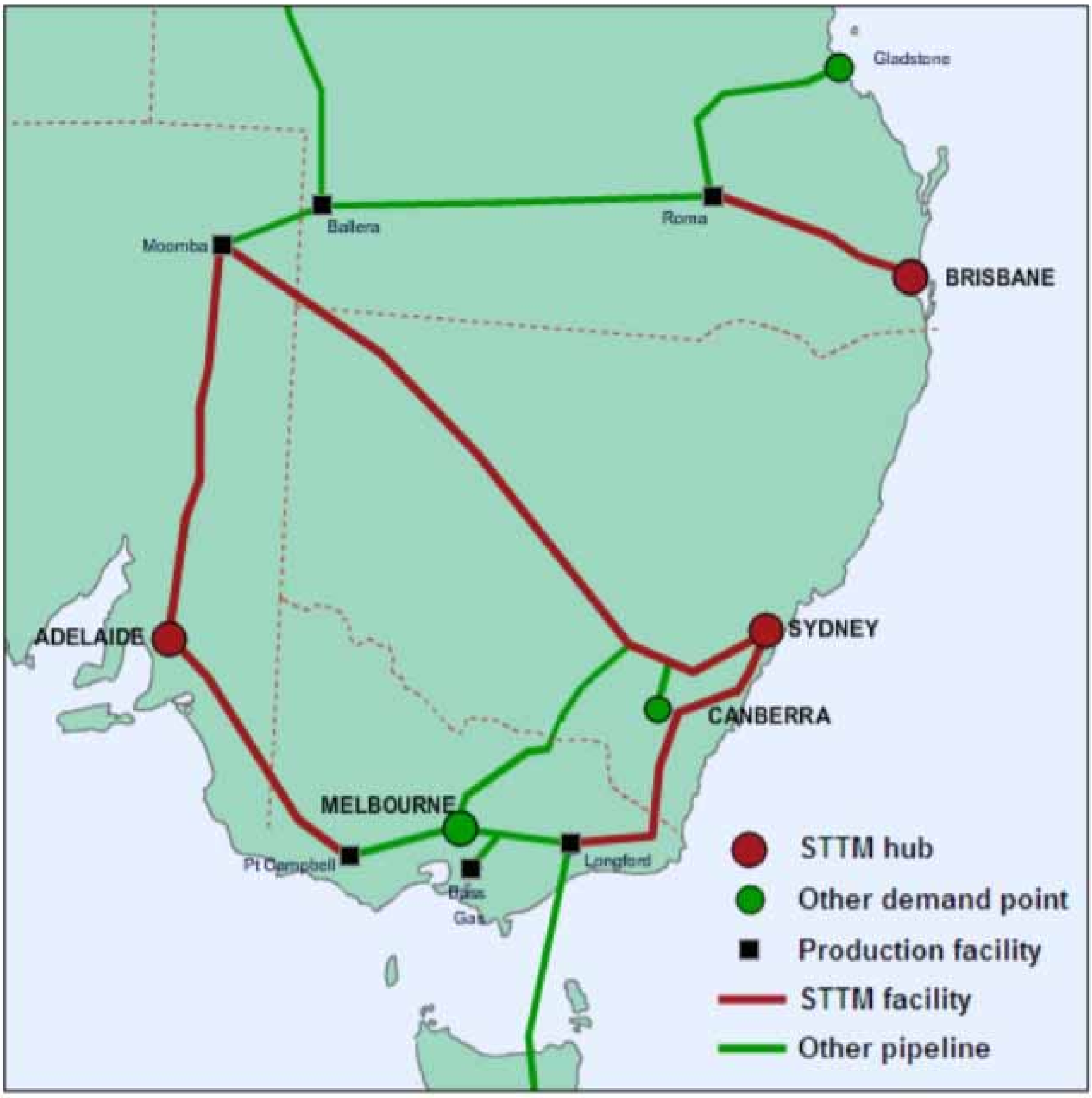
TOPIC	PROVISIONS				POLICY INTENT OF THE PROVISIONS
	NGL	NGR	NERL	NERR	
					The AER must monitor compliance with any conditions on which a trial waiver is granted and the provisions of a trial rule.

C SHORT TERM TRADING MARKET

C.1 Overview of the STTM

The short term trading market (STTM) is a market for the trading of natural gas at the wholesale level at defined hubs between pipelines and distribution systems. The STTM currently operates three hubs (Adelaide, Brisbane and Sydney) but has been designed to accommodate additional hubs in the future. Each hub is scheduled and settled separately, but all hubs operate under the same rules. At any hub, there can be multiple facilities that deliver gas to the hub (such as transmission pipelines, storage facilities, and production facilities) and multiple distribution systems that deliver the gas from the hub to consumers.

Figure C.1: STTM hubs are located at Adelaide, Brisbane and Sydney



Source: AEMO.

In the STTM, "shippers" deliver gas to be sold in the market,[86] and "users" buy gas for delivery to consumers (or for self-consumption). As the majority of gas bought and sold on the east coast is through long term bilateral contracts outside of the STTM, many participants are both shippers and users.[87] This is because all gas delivered to the hub is required to be transacted through the STTM, which can result in an entity selling gas into the STTM and purchasing it back each day.

The price transparency provided by the STTM means that the price of gas set daily by the market reflects the supply and demand situation, which in turn is intended to provide a more reliable price indicator for future investment in production, transmission, and distribution infrastructure.

Due to the physical characteristics of natural gas and the time it takes to flow through transmission pipelines, nominations by gas users are made to producers and pipeline operators a day ahead. Accordingly, the STTM design consists of two broad elements:

- the ex ante or commodity market — where supply and demand is matched for the following day and an ex ante price determined by the market operator; and
- on-the-day balancing mechanism — to account for differences during the gas day between the supply and demand schedules determined in the ex ante market and to ensure system security is maintained.

C.1.1 STTM overlay on the contract carriage pipeline framework

The underlying contractual arrangements between transmission pipeline operators and shippers, and between distribution systems and users, must be registered in the STTM with AEMO. Preservation of these arrangements was a key design feature of the market and, while it operates the market, AEMO has no role in how transmission pipelines, storage facilities, production facilities or distribution systems are operated and scheduled.

Every bid to buy gas and every offer to sell gas through the STTM must be associated with a trading right. AEMO requires shippers and users to hold trading rights with sufficient pipeline capacity for the quantities of gas they are scheduled to flow.

When pipelines are scheduled, the terms of haulage contracts usually give shippers with firm gas haulage rights priority over shippers with lesser priority haulage rights, such as contracts with a non-firm or as-available capacity. However, the STTM scheduling process does not take account of these priorities when scheduling offers other than to resolve tied offer prices.

If a pipeline's capacity is constrained, an as-available shipper may displace a firm capacity shipper in the STTM by offering gas at a lower price. This prevents the firm capacity shipper from using the pipeline capacity that it has funded.

In this situation, the as-available shipper pays a capacity charge based on the actual quantity of gas flowed. The firm capacity shipper who is displaced on that pipeline receives a capacity

86 STTM shippers may also buy gas and withdraw gas from the hub.

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

payment based on the amount of gas it offered into the market below the market price but which was not able to be scheduled.

C.1.2 STTM participants

All participants must register with AEMO.[88] The roles defined on the STTM are:

- STTM facility operator
- STTM shipper
- STTM distributor
- STTM user
- Allocation agent.

A party who wishes to submit offers and bids at a hub must be registered by AEMO at that hub as an STTM shipper or an STTM user or both. Their registration must be supported by trading rights that allow them to haul gas on a pipeline or withdraw gas from a distribution system.

STTM facility operator

STTM facilities can include transmission pipelines, and production facilities and storage facilities that inject gas directly into an STTM distribution system. STTM facilities are operated by STTM facility operators.

Specifically, an STTM pipeline operator (a type of STTM facility operator) operates a gas transmission pipeline that delivers gas from remote production and storage facilities to the hub. STTM pipeline operators schedule the delivery of gas into the pipeline based on STTM shippers' haulage priority and ensure that flows are kept within operational limits. They also measure the gas flowed into and out of the pipeline and allocate quantities between STTM shippers.

STTM facilities can include transmission pipelines, and production facilities and storage facilities that inject gas directly into an STTM distribution system. STTM facilities are operated by STTM facility operators.

Specifically, an STTM pipeline operator (a type of STTM facility operator) operates a gas transmission pipeline that delivers gas from remote production and storage facilities to the hub. STTM pipeline operators schedule the delivery of gas into the pipeline based on STTM shippers' haulage priority and ensure that flows are kept within operational limits. They also measure the gas flowed into and out of the pipeline and allocate quantities between STTM shippers.

STTM shipper

An STTM shipper is required to have a registered, contractual right to deliver gas from an STTM facility. Shippers delivering gas upstream of the hub are only required to register as an STTM shipper if they also ship gas through the hub. Only STTM shippers are able to offer gas

88 AEMO, *Overview of the Short Term Trading Market for Natural Gas*, December 2011, p. 7.

for sale on the STTM (see "trading participant"). STTM shippers can also bid to withdraw gas from the hub (to replenish gas stored in the pipeline, for example).

STTM distributor

An STTM distributor manages and operates a gas system that delivers gas from the hub to consumers. STTM distributors collect meter data at regular intervals, which they supply to AEMO for calculating the daily allocations made to STTM users. In Adelaide and Sydney, the STTM hubs each include only one distribution system, whereas there are two distribution systems in Brisbane.

STTM user

An STTM user has a registered, contractual right to withdraw gas from an STTM distribution system or an STTM facility. Typically, STTM users are retailers or large consumers who hold distribution contracts with STTM distributors. STTM users are able to bid for gas on the STTM as trading participants. Only STTM users are able to place price-taker bids—that is, to purchase gas at any price. Large consumers who register as STTM users are referred to as self-contracting users.

A transmission connected STTM user is a particular type of STTM user who has a registered, contractual right to withdraw gas from an STTM facility (instead of a distribution system). Typically, transmission connected STTM users are large consumers, such as power stations, who withdraw gas from a transmission pipeline. Other than their contractual arrangements, there is no difference between what a transmission connected STTM user and any other STTM user can do in the market.

Allocation agent

Pipeline operators, shippers, users, and AEMO (as retail market operator) must either act as or appoint allocation agents to determine the daily allocations submitted to AEMO.

C.2 Ex ante (commodity) market

The ex ante or commodity market is where shippers offer to supply gas and users bid to purchase gas that will flow the following day. Offers and bids can be submitted to AEMO up until 11.30am AEST.[89]

Transactions in the ex ante market can be thought of as falling into two categories. The first and most common relates to the same entity selling and purchasing gas through the hub. As all gas that flows through the distribution network within the hub must (under current arrangements) be transacted in the STTM, participants with underlying long term contracts that do not need to trade at the hub on an ex ante basis must still participate. This generally results in a retailer offering gas into the STTM and bidding to withdraw the same amount.

89 Rule 410(2)(c) of the NGR. The rule specifies that submissions made be made no later than 5.5 hours after the start of the gas day before that gas day. Part 26 of the NGR, introduced in 1 October 2019, defines a standard gas day across the east coast which begins at 6 am AEST.

In this instance, as a participant is on both sides of the transaction, there is no price risk in the ex ante market. For instance, if the retailer’s underlying gas contract price is $3/GJ but the STTM clears at $7/GJ, the retailer will effectively be selling and buying the gas to itself at $7/GJ in the STTM, and will have no additional price exposure. However, price risks do emerge through the on-the-day balancing mechanism if a retailer deviates from its ex ante schedules on the gas day.

The second category of transaction is where two different entities buy and sell gas in the ex ante market. A retailer who has expected demand at the hub of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ in the ex ante market and bid to withdraw 100 TJ. In this example, the retailer will be exposed to ex ante price risk on 20 TJ, which is the volume of gas not supplied through the long term contract.

STTM bids and offers can include up to 10 price-quantity steps. Offers to supply are given in increasing price order with increasing cumulative quantities. Bids to buy are given in decreasing price order with increasing cumulative quantities.

Prices in the STTM must be within a range of $0/GJ to $400/GJ,[90] although users can submit price taker bids that represent a quantity of gas the user will accept at any price. If the cumulative price over seven consecutive days reaches $440/GJ,[91] AEMO applies the administered price cap of $40/GJ for the whole of the gas day it is determined.[92] This mechanism is designed to protect participants from uncontrollable risks due to sustained high prices.

AEMO produces the market schedules and prices using an algorithm on the day before the gas day. The ex ante price is determined by stacking offers from lowest to highest price against bids to purchase gas from highest to lowest price.

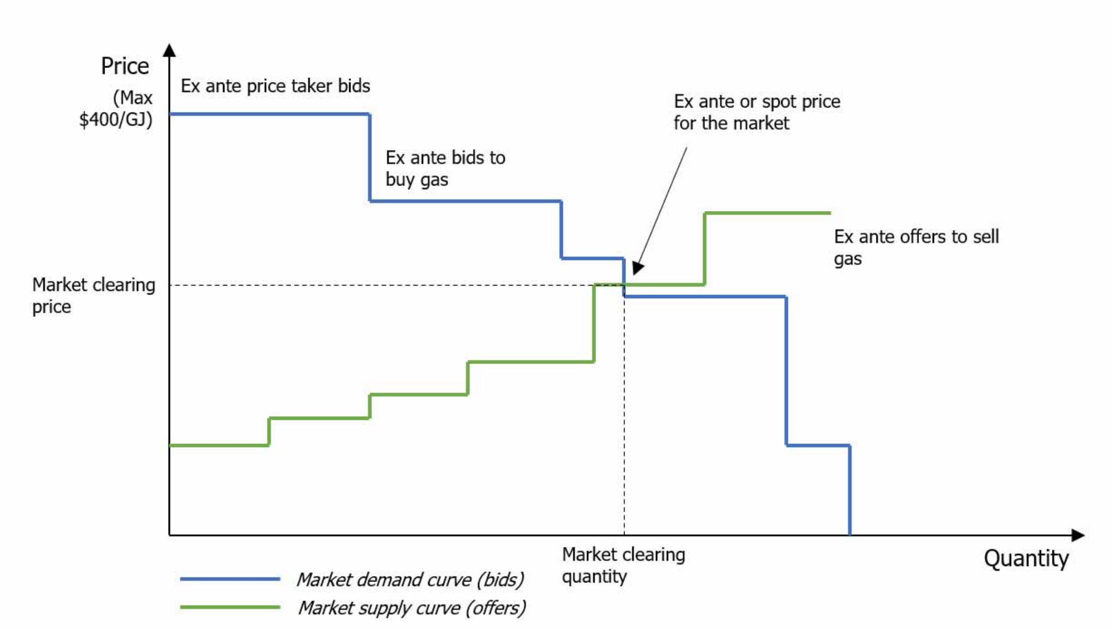
The point where demand intersects supply represents the marginal cost at which demand from all distribution systems is met by supply from shippers on STTM transmission pipelines and other hub facilities (see figure below). All of the gas that flows in accordance with the ex ante market schedule on the gas day is settled at the ex ante price.

90 Rule 364 of the NGR.

91 Rule 364 of the NGR. The cumulative price threshold is defined as being 110% of the market price cap.

92 Rule 428(6)(a) of the NGR.

Figure C.2: The ex ante market price is set where demand meets supply



Source: Figure based on AEMO, *An Overview of the Short Term Trading Market (STTM)*, p. 15 as reproduced in AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 242.

In situations where bids (including price-taker withdrawals) or offers have the same price and the total quantity bid or offered cannot be scheduled, then tie-breaking rules are applied to determine the schedule.

During this scheduling process, one or more pipelines might reach their hub capacity—the pipeline is then said to be capacity constrained. If demand at the hub has not been met when a pipeline becomes constrained, the scheduling process continues as before, but offers are only considered from unconstrained facilities. Demand can be satisfied from any STTM transmission pipeline or other facility subject to its physical capacity on the gas day.

After the ex ante market schedules are published, shippers make nominations to pipeline operators in accordance with their relevant contracts. This process is not part of the STTM and there is no requirement for pipeline nominations to match the quantities scheduled in the market. Similarly, the STTM has no involvement in any distribution network processes for managing the scheduling of withdrawals from a hub. If nominations differ from the STTM ex ante schedules, this is dealt with through the on-the-day balancing mechanism, which is discussed below.

C.3 On-the-day balancing mechanism

The on-the-day balancing mechanism is the second design element of the STTM, and is required due to the physical properties of natural gas. Unlike electricity, gas does not flow to its destination almost instantaneously. This requires users to provide producers and pipeline operators with forecasts of their demand the day before gas is required. On-the-day balancing is required to resolve the variations in ex ante schedules and actual flows on the gas day.

Unlike the Victorian DWGM, there is no opportunity for STTM participants to adjust their positions during the gas day. In order to manage imbalances that occur at the hub between the ex ante market schedule and actual physical flows, AEMO operates the following mechanisms throughout the gas day:

- Market Operator Service (MOS)
- Market Schedule Variations (MSVs)
- Contingency gas.

C.3.1 Market Operator Service

MOS balances the difference between the scheduled pipeline flows and what is actually delivered or consumed at the hub, and is the primary on-the-day balancing mechanism. It is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges.

MOS is procured each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. Shippers provide MOS increase offers for increased flows to the hub and MOS decrease offers for decreased flows to the hub, which are comprised of price-quantity steps.

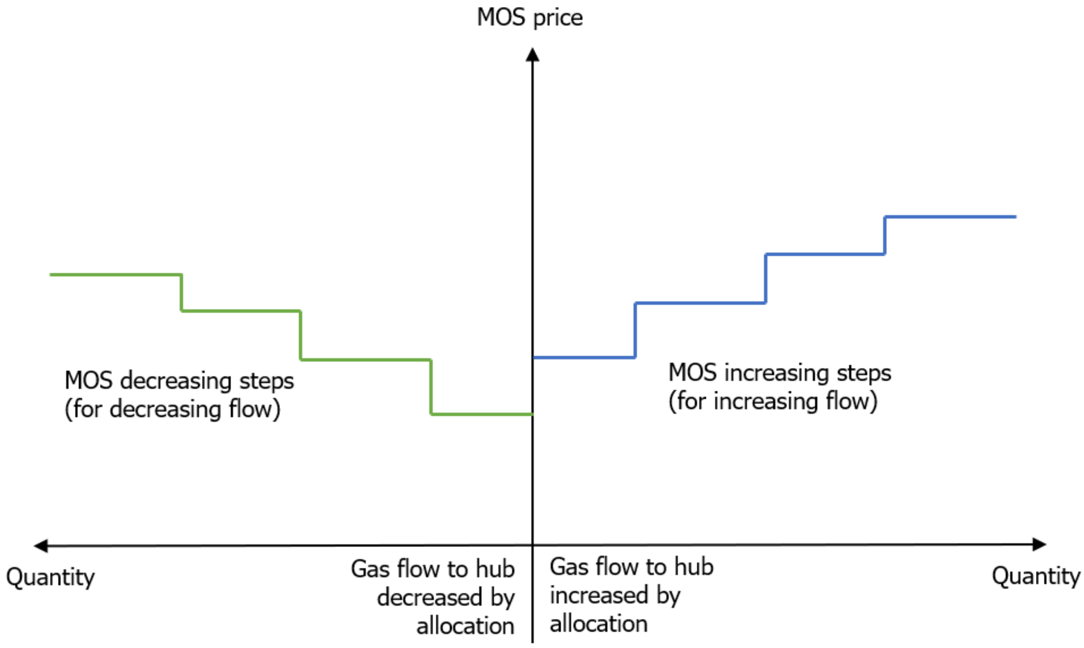
On a gas day where deviations from the ex ante schedules occur, MOS is allocated to shippers by pipeline operators in accordance with MOS stacks provided for each pipeline by AEMO. If demand at an STTM hub is higher than expected, and as a result pipeline pressures decrease below operational levels, the pipeline operator flows additional gas from linepack in accordance with the increase MOS stack. Similarly, if hub demand is less than expected, the pipeline operator decreases the flow of gas to the hub by storing gas in the pipeline in accordance with the decrease MOS stack.

After the gas day, the pipeline operators notify AEMO of all MOS allocations for settlement purposes. This information also feeds into setting the ex post imbalance price.

The figure below shows a MOS decrease stack on the left, where price increases as more gas is required to be stored in linepack, and a MOS increase curve on the right, where price increases for the more gas that is required to be supplied into the hub from linepack. A MOS cost cap of $50/GJ is the maximum amount that AEMO will pay for MOS.[93] This is designed to protect the market from having to fund high costs for MOS where there is a lack of competition in the provision of MOS.

93 Rule 364 of the NGR.

Figure C.3: MOS increase and decrease price stacks



Source: Based on AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 245. Original diagram supplied by AEMO.

The price offered by a shipper to provide MOS reflects the cost of the pipeline park-and-loan service, and associated haulage charged by the pipeline operator, but not the cost of replacing the gas supplied. When the market is short and MOS gas is required, the shipper is paid according to its MOS step price on a pay-as-bid basis. There is no cost to the market in accepting a MOS offer until MOS gas is actually allocated on a gas day.

AEMO pays the MOS provider for the additional gas, or charges it for taking gas from the hub, at the ex ante market price two days after the gas day. This D+2 ex ante price is used to price the cost of replacing MOS inventory as it allows the MOS provider to bid to purchase gas to resupply its MOS inventory at the same price that AEMO has paid it for supplying the MOS gas.

C.3.2 Market schedule variations

During the gas day, users' gas requirements become clearer and shippers are generally able to submit renominations to pipeline operators to adjust the flow of gas to the hubs. AEMO is able to account for intraday nominations, and shippers avoid deviation payments and charges, if shippers submit a market schedule variation (MSV) to AEMO to account for the changes.

MSVs are bilateral agreements negotiated between participants outside of the STTM that allow the quantity of gas by which a shipper varies from the market schedule to be matched by a receiving shipper or user. The receiving participant must confirm acceptance of an MSV before the variation can be applied in the STTM settlement process.

If the MSV results in a change in demand at the hub, the variation will attract a variation charge, which is designed to encourage more accurate day-ahead forecasting. Variation charges are calculated on a sliding scale on a quantity and percentage basis such that the larger the variation, the larger the charge. MSVs that do not change the net flow at the hub are not penalised.

The framework around variation payments and charges is designed to provide an incentive for shippers and users to forecast their expected volumes accurately, while acknowledging that some changes are inevitable under the day-ahead market design. Variation charges are lower than deviation penalties to encourage shippers to re-nominate expected changes in gas required to the pipeline operator.

C.3.3 Contingency gas

Contingency gas is a mechanism for balancing supply and withdrawals at a hub when the ex ante market and on-the-day pipeline flow variations are unable to match supply and demand within or over a gas day. Contingency gas provides pipeline operators and distributors with a means of avoiding, or at least minimising, the need to involuntarily curtail shippers supplying the hub or users at the hub.

AEMO procures contingency gas, but its use is determined in consultation with transmission pipeline and distribution network operators. Shippers able to increase supply to a hub and users and shippers able to reduce consumption will offer contingency gas to meet under-supply situations. Shippers able to decrease supply and users and shippers able to increase consumption at a hub will bid contingency gas to meet over-supply situations.

Trading participants can submit bids and offers for contingency gas at any time up to 6:00pm the day before gas day.[94] Contingency gas bids and offers are priced between the minimum and maximum market price caps. AEMO determines a price for contingency gas after the gas day, when all contingency gas called is known.

A high contingency gas price is paid to providers whose contingency gas increases supply and/or reduces withdrawals. This price is set at the contingency gas offer price of the most expensive contingency gas provider who is called.

A low contingency gas price is paid by contingency gas providers whose contingency gas decreases supply or increases consumption. This price is set at the contingency gas bid price of the least expensive contingency gas provider called.

C.4 After the gas day

After the gas day the following aspects of the market are required to be determined for settlement to take place:

94 Rule 438(1) of the NGR.

- actual gas flows
- ex post imbalance price
- deviation payments and charges
- market settlement shortfall and surplus.

C.4.1 Determining actual gas flows

After the gas day, transmission pipeline operators for each STTM facility measure actual pipeline flows and allocate these quantities to each shipper on that pipeline. Where the pipeline allocations at a hub deviate from the ex ante schedule, the pipeline operator allocates these deviations to MOS providers in accordance with the MOS stacks provided by AEMO.

Distribution meter data is collected over a range of time frames and requires that non-interval meter customers are profiled. The quality of meter data available improves over time, so the meter data provided for the first settlement run is generally inferior to that of subsequent settlement runs produced over a period of months. These are functions that AEMO carries out in its capacity as retail market operator and are not part of the STTM.

Settlement occurs monthly, but is recalculated after nine months due to the time it takes for meter data to be finalised. The STTM provides for further revisions for a period of 18 months if there is material impact on participants due to mistakes in the process or if faulty meters are discovered.

C.4.2 Ex post imbalance price

The ex post imbalance price is calculated after the gas day to determine a price that reflects the changes that actual flows to the hub would have had on the ex ante market. It is determined using the same data as the ex ante market schedules, but includes a dummy bid or offer that simulates the effect of the deviations, such as through MOS, if they had been scheduled in the ex ante market.

If more gas was scheduled than consumed on the gas day, the market supply curve is moved right by the quantity by which the market is long. If more gas was consumed than scheduled, the market demand curve is moved right by the quantity by which the market is short.

The ex post imbalance price is published after the gas day and can be used in settlement to calculate deviation payments and charges.

C.4.3 Deviation payments and charges

Deviations are the difference between the quantity of gas that the STTM is expecting to flow—as modified by MSVs, MOS and contingency gas—and the actual quantity of gas that flowed. As discussed above, actual quantities of gas that flow to and from the hub will not exactly match the ex ante market schedule for any given gas day.

Where a shipper has supplied more gas than was required in the market schedule, or a user consumed less gas than was expected in the market schedule (or is "long"), it will receive a deviation payment from AEMO. The deviation payment is calculated by multiplying the deviation quantity by the minimum of the ex ante price, ex post price, the decrease MOS price (if any) and the low contingency gas price (if any).

Where a shipper or a user is "short" at the hub, it must pay a deviation charge to AEMO. Deviation payments and charges are used to offset the cost of MOS gas. The deviation charge is calculated by multiplying the deviation quantity by the maximum of the ex ante price, ex post price, the increase MOS price (if any) and the high contingency gas price (if any).

Deviation payments and charges reflect the impact the deviation had on the STTM and will vary for each participant. However, because deviations and MOS are calculated on a different basis, there is usually a shortfall or surplus, which is dealt with through the settlement process described below.

C.4.4 Market settlement shortfall and surplus

Settlement occurs monthly and is net of all ex ante sales and purchases, deviation charges, variation charges, capacity charges, settlement revisions and any payments for MOS and contingency gas. The settlement payments to trading participants do not usually match the settlement charges paid by trading participants, with the various components above all contributing to the market being in surplus or shortfall.

For each month, the market must end up in balance with respect to trading income and outgoings. If there is a shortfall, any deviating parties are charged their share of the shortfall, pro-rated based on the absolute value of their deviations over the course of the month.

If there is a surplus, then the excess funds are returned to the deviating parties based upon their share of monthly deviations up to a cap of 0.14 $/GJ, with the residual amount being returned pro-rata based on withdrawals over the course of the month.

C.5 Unaccounted for gas

Unaccounted for gas (UAFG) refers to gas supplied into the gas network that is unaccounted for in deliveries from the network. It is calculated as the difference between the measured quantity of gas entering the network system (receipts) and metered gas deliveries (withdrawals). The underlying causes for UAFG arise from gas measurement and calculation errors and physical losses.

The arrangements for UAFG vary between each STTM hub. Across the STTM hubs, UAFG is regulated at a jurisdictional level by the Retail Market Procedures (RMPs).

In Adelaide, the distributor is responsible for the purchase and physical supply of UAFG each day. It purchases UAFG through a competitive tender process, with gas supplied by the successful tenderer after withdrawal from the STTM hub.[95]

95 Jemena Gas Networks (NSW) Ltd, *Matched allocation process*, Rule change proposal, 15 September 2014, p. 9.

In Brisbane, the host retailer[96] is responsible for supplying UAFG into the STTM hub. A separate commercial arrangement is in place for the retailer to recover its costs of supplying UAFG from the relevant distributors.[97]

In Sydney, like Adelaide, the distributor is responsible for the purchase and supply of UAFG. However, in Sydney, the distributor (Jemena Gas Networks (NSW) Ltd (Jemena)) makes use of the matched allocation mechanism provided for in the NGR, under which the gas purchased by Jemena is excluded from settlement through the STTM.[98]

Under a matched allocation agreement, one or more STTM shippers agree to provide a matched allocation quantity of gas to Jemena prior to it entering the Sydney STTM hub. The matched allocation quantity of gas delivered to the hub for each gas day by the STTM shipper(s) is required to match the matched allocation of gas withdrawn from the Sydney STTM hub that same gas day by Jemena.

Under the NSW RMP, UAFG quantities are not allocated to retailers through the gas retail market allocation process. Instead, Jemena is required to nominate a daily UAFG quantity to AEMO, and notify AEMO that this quantity of gas has been delivered to the market for that day. Jemena's nominated UAFG quantities are excluded from the retail market allocations and, as a result of the matched allocation process, from STTM settlements.

96 The host retailer in the RMP is the local area retailer under the NERL.

97 Jemena Gas Networks (NSW) Ltd, *Matched allocation process*, rule change proposal, 15 September 2014, p. 10.

98 Rules 500A-500B of the NGR; AEMC, *Matched allocation process in the STTM*, rule determination, 28 May 2015.

D DECLARED WHOLESALE GAS MARKET

D.1 Overview of the DWGM

The Victorian Declared Wholesale Gas Market (DWGM) is the longest-standing facilitated wholesale gas market in Australia, and is a virtual hub operating across the Declared Transmission System (DTS) in Victoria (see figure below).[99]

Figure D.1: The Declared Transmission System in Victoria

Source: AEMO.

The DWGM is a ‘gross pool’ market, which means that it is compulsory for market participants wanting to inject gas to, or withdraw gas from, the DTS to trade through the DWGM. Market participants are parties that trade directly in the DWGM and are made up of:

- retailers — who purchase gas from gas producers, offer it into the DWGM and then on-sell it to consumers
- market customers — large commercial and industrial customers who elect to trade directly in the DWGM

99 AEMC, *Consultation Paper: Victorian Declared Wholesale Gas Market Background Paper*, March 2019 at https://www.aemc.gov.au/sites/default/files/2019-03/Victorian%20DWGM%20background%20paper_0.pdf

- traders — who bid gas from, and sell gas to, gas producers and other market participants.

Gas producers and storage providers may also be market participants if they choose to directly bid gas into the DWGM.

Non-market participants include the declared transmission system service provider (DTS SP) (APA VTS Australia (Operations) Pty Limited (APA)), interconnected transmission pipeline service providers (which have pipelines connected to the DTS), distributors and end consumers (who purchase gas from a retailer).

D.1.1 Pipeline arrangements and the role of AEMO

In the DWGM, the DTS SP, APA, owns and maintains the DTS and makes the transmission pipeline available to AEMO under a contract known as the Service Envelope Agreement. AEMO manages receipt, transportation and delivery of gas.

The Service Envelope Agreement determines, among other things, the transportation capacity of the DTS and the obligations of APA and AEMO in relation to the delivery of the agreed capacity. With respect to transportation capacity, AEMO and APA are required to maintain an agreed common system model that is used, among other things, to determine system capacities.

Unlike contract carriage pipelines, shippers utilising the DTS cannot reserve firm capacity. They may, however, have an authorised maximum demand quantity (AMDQ) allocation or an AMDQ credit certificate (AMDQ cc). AMDQ was first allocated at market start and was (and has remained) commensurate with the capacity of the Longford-Melbourne pipeline at that time when it was the sole source of gas supply for the DWGM.

The increase in pipeline capacity resulting from an extension or expansion project is agreed between APA (as the pipeline owner) and AEMO (the system and market operator). Once agreement is reached and the new capacity becomes operational, new AMDQ cc are created.

AEMO also has a key role in operating and administering the gas market in the DWGM. As a gross pool, the market arrangements require market participants to bid their injections and withdrawals into the market, and forecast their uncontrollable withdrawals in order to access the DTS. It is AEMO's role to manage this bidding and matching process to determine the market clearing price and a schedule of gas flows for each market participant during the gas day (that is, the gas expected to be injected or withdrawn by each market participant at the various points on the system).

AEMO also manages the settlement process, which is conducted ex-post, including calculating charges associated with imbalance (caused by differences in a participant's daily gas injections and withdrawals), deviations (caused by differences between a participant's scheduled and actual behaviour), and ancillary and uplift payments (primarily generated by actions taken to manage constraints at particular locations on the system).

D.2 Market design features

D.2.1 Scheduling

It is compulsory for market participants within the DTS to trade all gas through the DWGM, including for participants who already own the gas that they intend to withdraw. Market participants offer gas to inject to, and bid to withdraw gas from, the market. These offers and bids are inputs to AEMO's market clearing engine which schedules injections and withdrawals of gas by minimising the total cost of supplying gas demand.

In order to be scheduled each gas day,[100] market participants are required to submit to AEMO:

- hourly demand forecasts for non-price sensitive load ('uncontrollable withdrawals')[101]
- daily bids for price sensitive load ('controllable withdrawals') and daily offers for both price and non-price sensitive injections[102]
- separate offers and bids must be made for each of the injections and withdrawals for each injection and withdrawal point
- each bid can include up to ten price/quantity pairs (bid steps)
- bid constraints which reflect both the ability of the participant to respond to AEMO's changes to scheduling instructions, and the physical or contractual limitations on the participant at the specific injection and withdrawal point. These bid constraints need to be accredited by AEMO before they are applied to injection and withdrawal points in the DTS.

Based on the above information, AEMO will:

- declare a market price (using the 'pricing schedule') — the price of the marginal unit of gas that would have been scheduled absent any transmission constraints on the DTS
- subject to the pipeline system security limits, schedule each market participant's injections and withdrawals with the objective of minimising the cost of supplying demand (using the 'operating schedule').[103]

The scheduling process occurs regularly at five pre-defined times within the gas day.[104] For the first schedule of the day, at 6 am, gas is scheduled and a market price is determined for the entirety of the upcoming gas day.

Each subsequent scheduling process then revises scheduling instructions and the market price for the *balance* of the gas day. AEMO will reschedule for the current gas day by revising or updating the schedules at intervals of four hours, with a larger eight-hour interval applying overnight (that is, 10 am, 2 pm, 6 pm, and 10 pm).

100 A gas day is 24 hours, commencing at 6 am Eastern Standard Time.

101 These forecasts are then automatically 'bid' into the DWGM at the market price cap.

102 See AEMO, Victorian DWGM WebExchanger User Guide v7.1, Chapter 5 for information on how participants submit offers and bids.

103 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013.

104 Ad hoc schedules may also occur but only if there are impending or imminent threats to system security requiring urgent action.

The reschedules determine prices and quantities for all the remaining hours in the gas day following the time of that schedule. A reschedule can include updated demand forecasts, updated bids and offers, as well as any changes to parameters under the control of AEMO.[105]

AEMO provides a schedule a number of times each gas day to provide hourly injection schedules for each market participant, and schedules for any controllable withdrawals, using market participants' submitted bids and demand forecast as primary inputs.[106]

AEMO uses this information to produce and publish pricing and operating schedules at each scheduling time:

- Pricing schedules:
  - determine the ex-ante market prices based on the bids and demand forecasts (i.e. using a 'bid stack') for all locations on the network (discussed in more detail below)
- Operating schedules:
  - determine individual market participants' scheduled hourly injections and withdrawals at each injection/withdrawal point
  - take into account physical constraints, linepack distribution, system limits on pressure and gas flows and demand and supply applicable to each node[107]
  - are optimised using a market clearing algorithm which minimises the cost of supplying the forecast gas demand within the pipeline system security limits
  - determine quantities and direct the operation of the gas system and injections into the system over the gas day.

On any given gas day, AEMO prepares and issues at least nine pricing and operating schedules (see the figure below):

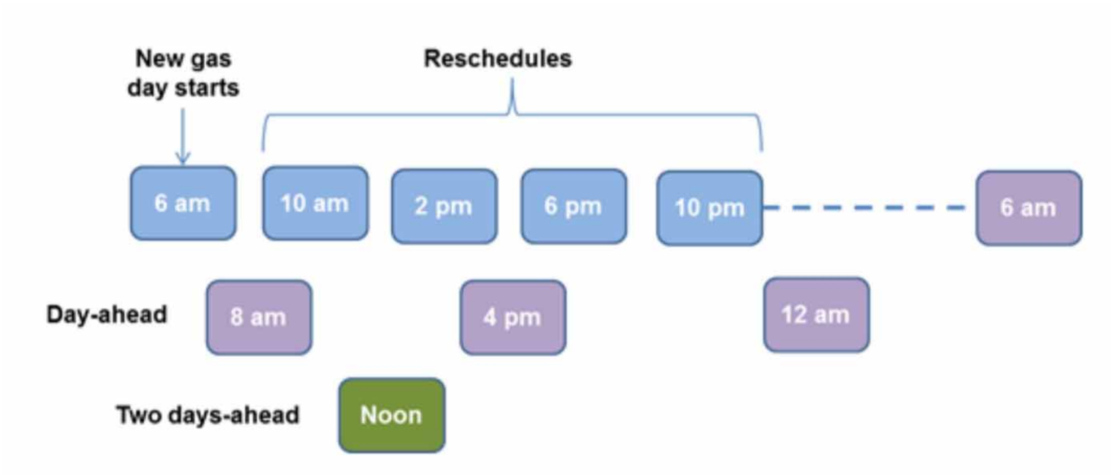
- five standard schedules for the current gas day at four-hour intervals at 6 am, 10 am, 2 pm, 6 pm and 10 pm
- three gas schedules for the next gas day at 8 am, 4 pm and 12 am
- one schedule for two days ahead at 12 pm
- ad hoc schedules(s) between standard schedules on the current gas day, but only if there are impending or imminent threats to system security requiring urgent action. These ad hoc schedules do not alter the market prices but rather the operating schedule quantities only.

105 Market participants may update their bids and demand forecasts up to one hour prior to the time a reschedule takes effect.

106 Market participants who supply uncontrollable withdrawals must submit hourly site- and non-site specific demand forecasts to AEMO. It should be noted that market participants enter market bids for each schedule while demand forecasts are entered for each hour of the gas day.

107 Linepack refers to the amount of gas that is stored in a pipeline. AEMO allows linepack to vary throughout the day but maintains an end-of-day target.

Figure D.2: The daily preparation of schedules by AEMO



Source: AEMC, *East coast wholesale gas market and pipeline frameworks review*, stage 1 final report, 23 July 2015, p. 263.

The 6 am schedule, known as the beginning-of-day (BoD) schedule, covers the 24-hour period from 6 am to 6 am the following day. Information used and issued in the BoD schedule is updated in subsequent schedules which provide for any changes in the remaining hours in the gas day. The period between scheduling times is called the 'scheduling interval', and the period from any point in a day to the end of the gas day is referred to as the 'scheduling horizon'. The scheduled quantities are for the whole gas day but only the part of the gas day that remains (the scheduling horizon) can be changed in subsequent schedules. Each of the current day schedules overrides the existing schedule for the remainder of the gas day. For example, the 2 pm schedule will replace the 10 am schedule for the interval 2 pm to 6 am the following day.

After the scheduling process, each market participant receives the key output of the operating schedule — an individual market information bulletin board report detailing what quantity of gas and where they are committed to inject or withdraw for each hour of the gas day.

D.2.2 Bidding procedure

There are three concepts of supply and demand in the DWGM which are important for understanding the operation of the market:

1. Controllable withdrawals (demand):
   a. Market participants can make offers to withdraw gas from the market with a defined gas quantity and price.
   b. This type of withdrawal can respond to the wholesale price and follow schedules and so is terms 'controllable withdrawal'.
2. Uncontrollable withdrawals (demand):

   a. Most of the gas demand in the DWGM is retail load that varies with temperature, seasons, day of week, weather conditions and various other external factors, for instance:
      i. withdrawals include gas demand from households (for heating, cooking and hot water) which are typically winter peaking, small business and large business/industry
      ii. gas fired generation, which typically peaks in summer to meet high electricity demand.
   b. Since these withdrawals do not easily respond to the wholesale price and are not capable of following a schedule, they are termed 'uncontrollable withdrawals'.
3. Injections (supply):
   a. Market participants need to have contracts with producers, storage providers, or an interconnecting transmission pipeline to be able to inject.
   b. Similar to controllable withdrawals, market participants can make offers to inject gas to the market with a defined gas quantity and price.
   c. Injections are termed 'controllable' because they can respond to the wholesale price and follow schedules.

Market participants who intend to inject gas to the DTS must submit offers to the DWGM. Similarly, market participants who intend to withdraw gas from the DTS must submit bids to the DWGM.

Market participants can specify up to ten bid steps of prices and daily quantities in each offer or bid for each injection and controllable withdrawal point:

- For offers, bid steps are provided in increasing order of price with increasing cumulative quantities.
- For bids, bid steps are provided in decreasing price order with increasing cumulative quantities.

Bid prices can vary between $0/GJ and the market price cap which is currently set at $800/GJ.

Market participants may revise price and quantity offers and bids at least nine times for each gas day. However, the revised total offer and bid quantities must not be less that that already scheduled in any previous scheduling interval on that gas day. All offer and bid quantities, including rebids, are for the 24-hour gas day.

D.2.3 Determining the market price

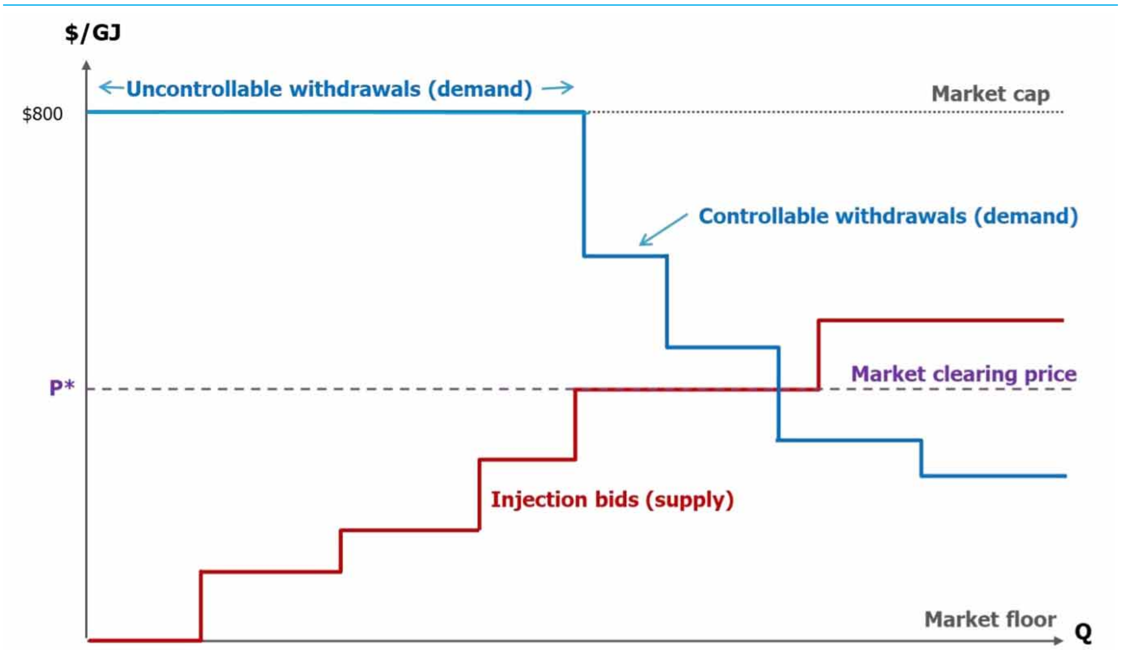
The market price is determined in the pricing schedule as follows:

- Gas withdrawals (controlled and uncontrolled withdrawals) are met by the cheapest gas offers in the system, i.e. through a 'bid stack' process.
- The optimisation process takes into account any transmission constraints within the DTS affecting withdrawals.

- The market price is determined by the marginal price of the cumulative offer quantities that are required to meet the aggregate of all market participants' demand forecasts and controllable withdrawal bids, i.e. the price of the most expensive unit of gas needed to satisfy demand.

The price is set at the level at which supply and demand are equal. This is demonstrated in the figure below. Demand is represented in blue, with uncontrollable withdrawals bid at the market price cap and controllable withdrawals making up the remaining curve in descending order of price. The supply curve, shown in red, represents the offer stack in order of price. The market clearing price, P*, is the price at which supply intersects demand.

Figure D.3: Price determination in the DWGM



Source: AEMC.

D.2.4 Curtailment rights

The Victorian arrangements for curtailment of gas usage or consumption to manage emergencies and/or preserve system security have been developed by AEMO in consultation with the Victorian Government. Where curtailment is required due to a transmission constraint, the first customers to be curtailed are tariff D customers[108] that hold no market benefit instruments or that have used in excess of their assigned market benefit instruments.[109] These instruments are described below.

108 Tariff D customers are large customers with daily demand meters and are typically industrial sites.

109 These arrangements are published as the Gas Load Curtailment and Gas Rationing and Recovery Guidelines on AEMO's website. The guidelines provide classifications of gas customers, and set out the priority order under which each class of gas customer will be curtailed if curtailment is required to maintain system security. The curtailment of customers who do not hold AMDQ or AMDQ cc reflects requirements under AEMO's Access Arrangement and rule 343 of the NGR, and is implemented by Table 0 of the Curtailment Tables.

D.3 Wholesale payments

In the course of trading gas within the DWGM on a given day, market participants may be exposed to:

- payments or charges related to selling or buying gas from other market participants at the market price
- payments or charges aimed at recovering the cost of any transmission constraints within the DTS.

D.3.1 Payments for gas at the market price

Participants offer gas into the wholesale market through a competitive bidding process. These offers are stacked in order of price and cleared against the aggregate sum of total forecast demand and controllable bids in order to determine the market price for gas within the DTS.

When trading gas within the DWGM, market participants may incur or receive imbalance payments and/or deviation payments for the gas they have bought or sold at the market price.

Imbalance payments

Imbalance payments are payments for the net difference between scheduled injections and withdrawals of gas by a market participant. Imbalance payments are determined on an ex-ante basis and can be positive or negative.

The daily imbalance payment for each market participant is calculated based on:

- the difference between their scheduled daily injections and withdrawals of gas as at 6 am, multiplied by the 6 am market price
- changes to the difference between their scheduled daily injections and withdrawals of gas at each reschedule, multiplied by the reschedule market price.

In summary, if a market participant:

- withdraws and injects the same quantity of gas over the course of the day the imbalance payment will be zero
- withdraws more gas than it injects over the course of the gas day the imbalance payment will be positive (the market participant has purchased gas from the market)
- withdraws less gas than it injects over the course of the gas day the imbalance payment will be negative (the market participant has sold gas to the market).

Deviation payments

Deviation payments are used to settle differences between market participants' scheduled dispatch instruction and actual dispatch outcome. To be clear, this contrasts with imbalance payments, which settle on the difference between scheduled injections and scheduled withdrawals.

In contrast to imbalance payments, deviation payments are calculated on an ex-post basis. That is, they are paid at the next scheduled market price after the scheduling period in which the participant deviated from their scheduled amounts.[110] This is because variations in a market participant's actual behaviour will have physical and financial impacts on the outcomes of the next schedule. The deviation payment is calculated as the difference between the following for each market participant, multiplied by the next scheduled market price:

- actual withdrawals less scheduled withdrawals, and
- actual injections less scheduled injections.

D.3.2 Payments related to transmission constraints

The presence of pipeline capacity constraints means that gas demand cannot always be met by the cheapest sources of supply. Consequently, there are a number of additional payments that market participants receive in situations where pipeline capacity constraints bind and their more expensive gas offer is required to be constrained on.[111] The total value of these payments is then recovered through uplift payments that are charged to the notional causers of the transmission constraint.

Ancillary payments

It is not always possible to schedule the cheapest gas to meet the required demand for a given gas day. If the system is congested, gas that is more expensive than the market price may be scheduled. Ancillary payments are compensatory payments to market participants whose more expensive gas offer is required to be constrained on as a result of the congestion.

The figure below provides an example of a situation where an ancillary payment will be made. In this case, there is a binding constraint on one of the pipelines that is preventing a participant from injecting its offered gas, represented as the dashed segment of the supply curve in red. The market price is set at the unconstrained optimal quantity and price indicated by the purple line, where the demand curve intersects the dashed supply curve at the market quantity Q*.

However, as some gas is constrained off,[112] the supply curve effectively shifts to the left by the constrained amount so that an amount of the next cheapest source of unconstrained gas that can be dispatched must be constrained on to satisfy the full market quantity Q*.

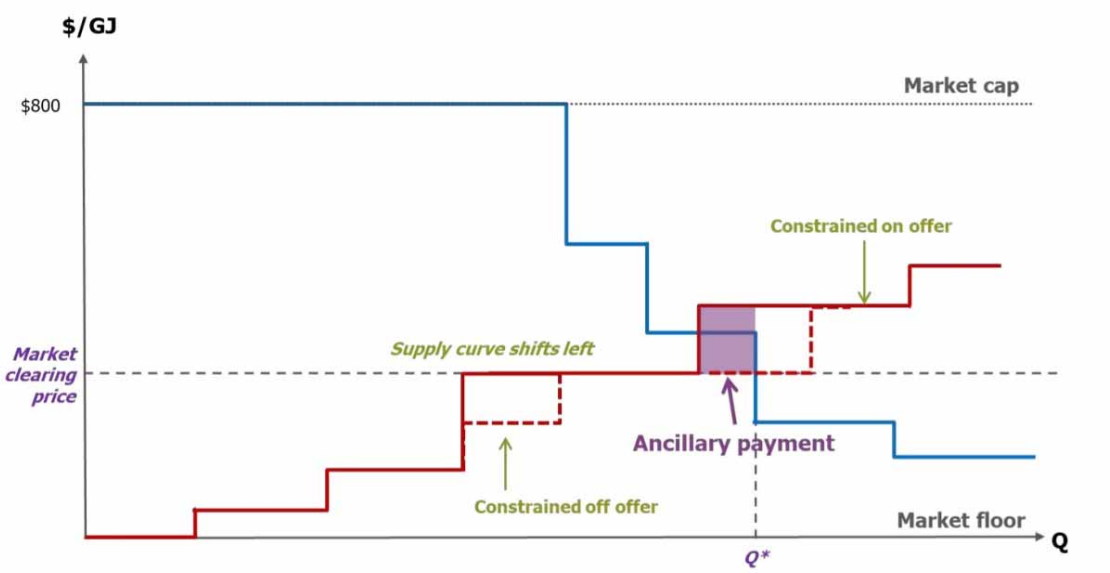
The market participant whose gas has been constrained on is compensated by an ancillary payment (represented by the purple rectangular area in the figure) so that it receives in total (ancillary payment plus market price) its offer price for the constrained on gas. There are no ancillary payments made to market participants that are constrained off.

110 For example, a deviation in the 10 am to 2 pm interval is settled at the 2 pm scheduled market price. Deviations in the last schedule of the gas day are settled at the following 6 am price.

111 Gas is constrained on when an injection is scheduled despite being offered at a price above the market price.

112 Gas is constrained off when it is not scheduled despite being offered at a price below the market price (or bid at a price above the market price if it is a withdrawal).

Figure D.4: Determination of 'constrained on' ancillary payments



Source: AEMC analysis.

Uplift payments

The total cost of ancillary payments are recovered from market participants through uplift payments. There are four categories of uplift payments:

- Congestion uplift — This is charged to market participants that are scheduled to withdraw or inject in excess of their allocated portion of the physical capacity of the system, as defined by their authorised maximum interval quantity or uplift hedge protection, derived from AMDQ. AMDQ therefore provides financial protection against congestion uplift, but this protection is limited because it is not granted if a participant is not injecting gas. As will be explained below, from 1 January 2023, following the removal of the AMDQ regime, congestion uplift payments will no longer be required.[113]
- Surprise uplift — This is charged to market participants that have caused a constraint by 'surprising' the system. This can occur when the participant deviates from their scheduled injections and/or withdrawals or if they change their demand forecast in the following period. Surprise uplift occurs because gas does not flow instantaneously. For example, if demand is unexpectedly high in Melbourne it may be too late to schedule gas from a distant but cheaper injection offer. Instead, a closer but more expensive source may need to be constrained on.
- DTS SP congestion uplift — This is charged to the DTS SP in situations where it is determined that the DTS SP caused congestion by not making the necessary plant or pipeline capacity available as required under the service envelope agreement.

113 See AEMC, *DWGM simpler wholesale price*, Rule determination, 12 March 2020.

- Common uplift — This includes costs that cannot be allocated by the above means and are paid by market participants in proportion to their withdrawals on the relevant day.

D.3.3 Payments related to unaccounted for gas

Under Part 19 of the NGR, AEMO is required to make procedures ('Distribution UAFG Procedures') that require it to calculate UAFG in a DDS and determine the payments to be made as between retailers and distributors.[114] The NGR requires the assignment of UAFG benchmarks for this purpose.[115] These benchmarks are determined by the economic regulator in Victoria, the Essential Services Commission (ESC). The ESC's Gas Distribution System Code (GDSC) sets out UAFG benchmarks, expressed as a percentage of the aggregate quantity of gas injected into the distribution system for each Victorian gas distributor.[116]

The GDSC requires gas distributors to use reasonable endeavours to ensure that UAFG is less than their benchmark. AEMO administers an annual reconciliation between gas distributors and retailers based on whether actual UAFG is over or under the benchmark.[117] Under the Victorian UAFG model, retailers are required to purchase sufficient gas to cover customer consumption and actual UAFG. If actual UAFG is greater than the benchmark, the relevant gas distributor is required to compensate the retailers for the UAFG in excess of the benchmark. Where actual UAFG is lower than the benchmark, the retailers make reconciliation payments to the relevant gas distributor.

D.4 Market benefit instruments

There are two types of instruments that market participants use in the DWGM to gain preferable access to the DTS and to manage exposure to uplift payments. These are authorised maximum daily quantity (authorised MDQ) and authorised maximum daily quantity credit certificates (AMDQ cc). These instruments differ in respect of location on the network and time validity but are similar in respect of the rights provided to holders. Therefore, unless specifically indicated any reference to AMDQ refers collectively to both authorised MDQ and AMDQ cc.

As explained below, the AMDQ regime will be replaced from 1 January 2023 with a system of entry capacity certificates that provide injection tie-breaking benefits and exit capacity certificates that provide withdrawal tie-breaking benefits.[118]

The initial allocation of authorised MDQ occurred at the commencement of the Victorian DWGM and is consistent with the capacity of the Longford to Melbourne pipeline.[119] The total authorised MDQ was set at 990 TJ/day which represented the peak capacity of the Longford to Melbourne pipeline. It was allocated in perpetuity to existing and committed new loads at the time, as follows:

114 Rule 312(10) of the NGR; AEMO, *Wholesale Market Distribution UAFG Procedures (Victoria)*.
115 Rule 235(8) of the NGR.
116 Essential Services Commission, *Gas Distribution System Code*, v14.
117 Essential Services Commission, *Gas Distribution System Code*, v14, cl 2.4.
118 See AEMC, *DWGM improvement to AMDQ regime*, rule determination, 12 March 2020.
119 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market,* July 2013, p. 29.

- for Tariff D[120] large customer sites, typically with demand exceeding 10 TJ per year, authorised MDQ was allocated to each site equal to their existing contract maximum daily quantity with revisions approved by an independent panel
- for the New South Wales interconnect, Wimmera pipeline and Murray Valley towns approximately 18 TJ of authorised MDQ was allocated
- for Tariff V customers, the remaining balance of the 990 TJ/day was allocated as a block — that is, to all residential and small-to-medium sized commercial and industrial customers.

Most large commercial and industrial customers hold authorised MDQ allocated directly to their sites. Authorised MDQ is only valid for the withdrawal of gas made at the delivery point at which it was first allocated. Authorised MDQ is valid in perpetuity. The right may be relinquished, in which case AEMO may re-allocate the authorised MDQ.

APA (as owner of the Victorian DTS) and AEMO (as operator of the DWGM) may agree to extend or expand the capacity of the Victorian DTS through existing pipeline augmentation or new pipelines. This expansion of capacity may result in the creation of additional AMDQ cc. AMDQ cc have been created to provide similar benefits in terms of the limited physical access rights and market rights to those arising from AMDQ issued on the Longford to Melbourne pipeline but differ in respect of location and time validity. AMDQ cc provides rights for a set term (usually the same period as the DTS access arrangement period). AMDQ cc is not allocated directly to a customer or customer site but rather to a market participant (who may be an end customer but is typically a retailer).

D.4.1 Rights and benefits to AMDQ holders

There are two different types of right or benefit that are created by holding AMDQ:

1. Physical access rights: holders of AMDQ receive pipeline access benefits above non-AMDQ holders during periods of pipeline congestion.
2. Financial rights: market participants can use part or all of their AMDQ to partially hedge against congestion uplift payments.

Physical access rights

Holders of AMDQ have the following physical access rights:

1. Curtailment 'protection' rights — customers that do not hold AMDQ, where operationally practicable, will have their gas supply curtailed ahead of customers sites with AMDQ in the event of transmission constraints resulting in supply shortfalls.
2. Injection tie-breaking rights (also known as priority in scheduled injections) — where there are equally priced offers, participants with AMDQ are scheduled first.
3. Withdrawal tie-breaking rights (also known as priority in scheduled withdrawals) — when there are equally priced bids for controllable withdrawals, participants with AMDQ are scheduled first.

120 Tariff D customers are large customers with daily demand meters and are typically industrial sites.

Financial rights

AMDQ is used to protect holders against congestion uplift payments that arise because of capacity limits in the DTS. This protection is called 'uplift hedge'. Uplift hedge is the amount of AMDQ that a participant nominates to use as a hedge against congestion uplift payments. The nominated amount must be supported by scheduled injections from the nominated source of gas supply.

D.4.2 Acquiring AMDQ

AMDQ can be acquired in a number of ways (these are different for authorised MDQ and AMDQ cc), including by a participant:

- entering into an agreement with existing holders of authorised MDQ to transfer an agreed quantity from one site to another or to the reference hub
- entering into an agreement with existing holders of AMDQ cc to transfer an agreed quantity at the reference hub
- applying and negotiating with the DTS service provider for AMDQ cc when it expands the capacity of the DTS or when existing AMDQ cc contracts that others hold expire
- contracting with the DTS service provider to privately expand the DTS capacity
- bidding for and purchasing spare AMDQ cc at auctions conducted by AEMO from time to time.

Historically, limited quantities of AMDQ have been traded between participants.

D.4.3 Replacement of AMDQ regime with capacity certificates regime

In March 2020, the AEMC made a final rule determination amending the NGR to replace the current AMDQ regime in the Victorian DWGM with a new entry and exit capacity certificates regime. The rule commences on 1 January 2023.[121]

Capacity certificates are for entry or exit within a zone and AEMO is required to determine the capacity certificates zones and publish these in a register. The allocation of capacity certificates will primarily occur via a capacity certificates auction, which will be operated by AEMO. AEMO is also required to conduct system capability modelling at least annually to inform AEMO's determination of the types and amounts of capacity certificates available at each auction.

When implemented, the final rule will:

- improve the ability of market participants to obtain capacity certificates to manage scheduling risk through tie-breaking benefits
- create a level playing field for all market participants to obtain capacity certificates through primary auctions, which will allow them to be allocated to those that value them most and will promote efficient use of pipeline capacity

121 See AEMC, *DWGM improvement to AMDQ regime*, rule determination, 12 March 2020.

- encourage more efficient allocation of pipeline capacity by allowing market participants to buy a set of entry and exit capacity certificates that give greater price and volume certainty to their preferred gas transportation pathways
- improve and simplify the current arrangements, which may encourage new entrants and promote competition in upstream and downstream markets and inter-regional trade.

E METERING AND TECHNICAL REQUIREMENTS

A gas meter is a device that records natural gas consumption in households and businesses. This data is relayed to energy retailers for the purpose of billing. A property's gas usage is measured in megajoules (MJ). The appliances that consume natural gas will detail energy consumption in terms of megajoule-hours (MJ/h). Gas meters play an integral role in ensuring customers are billed accurately for their usage and this function must be considered when natural gas equivalents (and, later other gases) are integrated into the gas market.

While metering and technical standards are also covered in the facilitated markets and regulated retail markets chapters of this consultation paper as relevant, this appendix sets out:

- an overview of metering and the regulatory arrangements
- technical challenges in introducing natural gas equivalents into existing gas infrastructure
- the initial identified gaps in the framework.

E.1 An overview of metering and its regulatory arrangements

There are currently different national and jurisdictional arrangements for metering. The Australian Energy Market Agreement (AEMA) separates these functions into:

- National functions — cover obligations to install, maintain and read meters. These functions are related to other national functions including retail market balancing regimes, settlements and customer transfers.
- State and territory functions — cover policies on types of meters required for specific customer classes, accredited service provider arrangements and load profile arrangements.

The key elements and location of the metering framework as it applies to natural gas and the policy intent of those elements are described in more detail in the table below.

Table E.1: Gas metering arrangements in the national regulatory framework

PROVISIONS	POLICY INTENT OF PROVISIONS
NERL Division 10 Section 237(2)(ia)	The NERL includes: • key provisions relating to the use of prepayment meter systems • heads of power for the making of NERR in relation to charging and billing rules, and bill content, including the provision of information to customers about metering and consumption data on bills.
NERR Part 2, Division 4	The NERR regulate aspects of metering as it relates to billing under customer retail contracts and prepayment meter systems. In relation to billing under customer retail contracts,

PROVISIONS	POLICY INTENT OF PROVISIONS

	the NERR includes detailed requirements on the form and content of bills including regulating:
	• The basis for bills, including requirements for:
	    • small customer bills for the consumption of gas to be based on an actual reading of the relevant meter or meter data determined in accordance with the metering rules, estimates of consumption or another method agreed with the customer
	    • the retailer to use its best endeavours to ensure that actual readings of the meter are carried out as frequently as is required to prepare its bills consistently with the metering rules and in any event at least once every 12 months.
	• how estimates can be used as a basis for bills
	• contents of bills (including whether the bill is based on a meter reading or estimation, the value of meter readings at the start and end of the billing period and details of consumption or estimated consumption of energy),
	• customer access to historical billing information
	• bill dispute provisions under which meter reads or metering data can be checked.
	The NERR does not specify how meter reads are to be undertaken or metering data is to be collected and provided but requires that this occurs under the "metering rules". For gas, the metering rules are in the applicable RMP (see section on retail market procedures below).

NGL Section 91A(e) Schedule 1, items 55G to 55I	The NGL includes the high-level governance framework for metering, including: • specifying that a statutory function of AEMO is to facilitate retail customer transfer, metering and retail competition (including balancing, allocation and reconciliation of gas deliveries and withdrawals to and from subnetworks) • providing a head of power for the making of NGR in relation to metering, the registration of metering installations and the regulation of persons providing metering services • providing a head of power for the making of the RMPs by AEMO that may deal with matters specified by the NGR or

PROVISIONS	POLICY INTENT OF PROVISIONS
	any other matter relevant to a regulated gas retail market on which the NGL or NGR contemplate the making of Procedures.
NGR Section 135EA(1)(e) Section 135EA(2)(j)	The NGR provides heads of power for the making of: • Retail Market Procedures in relation to the collection, estimation and use of metering data related to a regulated retail gas market • Wholesale Market Procedures in relation to metering (including metering communication and the metering registers). The NGR also includes: • detailed provisions relating to metering arrangements for the Victorian DWGM (Part 19 of the NGR). These metering arrangements support gas balancing and allocation processes in this market • billing and payment rules regulating the payment of distribution service charges by retailers and the required basis for that charging (i.e. metering data or estimated meter readings).
Retail Market Procedures	AEMO has made RMP under the NGL governing the regulating the operation of regulated retail gas markets in NSW and the ACT, SA, Victoria and Queensland. AEMO also administers the AEMO retail market scheme under the Energy Coordination Act 199 (WA) for the gas retail market in Western Australia. Each of the Retail Market Procedures made under the NGL regulate metering and the allocation of unique identifiers for meters at each delivery point in the retail market (MIRN) and MIRN discovery requests. In all jurisdictions except Victoria, the RMPs also regulate: • arrangements under which the gas injected and withdrawn from network sections that are not short term trading market (STTM) distribution systems is balanced and allocated to retailers • for STTM distribution systems, STTM system allocation processes arrangements in relation to unaccounted for gas.

E.1.1 Current operation of metering

Current gas meters in Australia measure in either metric or imperial units, with modern metric meters replacing older imperial meters. In Australia, most residential homes have a diaphragm gas meter which only measures the volume flow of gas to the property. The type of gas meter connected to a property will depend on the gas pressure available in that specific area and the type of regulator on the gas meter.

Thermal gas meters are another type of gas meter which measure the heating value at the point the gas is used. Thermal meters, however, are not widely used and are not representative of the typical meter present in most Australian homes and businesses. As a result, heating values are typically not measured at residential premises. This is relevant to the introduction of natural gas equivalents and other gases in Australia as the heating value is used to convert gas volume flow to gas energy flow, assisting the billing process.

Rather than measuring heating values at the point of consumption:

- In the DWGM heating values are measured on a market wide basis, determined through a real time transient model, to track gas composition. The model helps determine the heating value of gas supplied to networks, which is then combined with gas flows to measure energy flows.
- In the STTM, heating values are measured differently according to the relevant jurisdictional requirements.

With the introduction of different gases, it is likely that it will be important to measure heating values more often and at more points in the gas distribution system to accurately determine the amount of gas used and to bill customers accordingly. The introduction of hydrogen as a constituent gas in a natural gas equivalent will change the energy per unit of volume in the natural gas equivalent delivered to end users.

E.2 Technical challenges in introducing natural gas equivalents into existing gas infrastructure

Jurisdictional arrangements, including regulations necessary to accommodate natural gas equivalents, are matters for jurisdictional governments and are outside the scope of the AEMC's review. The technical challenges associated with introducing natural gas equivalent blends are set out here for information and to highlight the issues associated with the incorporation of natural gas equivalents and, in the future, other gases.

Suitability in pipelines and for end uses

The suitability of hydrogen blends and renewable gases for different pipeline infrastructure and for different end users depends on the technical capability of the pipeline and the ability of the end user to accept a natural gas equivalent.

Different distribution systems will have different types of pipes and not all of these will be suitable for hydrogen or other renewable gas blends. The durability and integrity of the existing gas distribution system must be considered within the technical requirements of the gas system to manage the delivery of renewable gas blends. For example, hydrogen can significantly reduce the mechanical performance of steel and lead to embrittlement of the pipe with implications for the safe transport of gas blends to end users.[122]

Many end users of natural gas may be able to accept natural gas equivalents for their end uses. For example, in residential heating or cooking appliances. However, some industrial processes may not be able to accept natural gas equivalents as a substitute for natural gas, or may not be able to do so at present. This is most relevant where natural gas is used as a feedstock in an industrial process such as fertiliser manufacture. As a consequence, in defining a natural gas equivalent it has been important to consider the ability of end users in any given distribution system to utilise the gas in their existing processes and appliances.

See chapters on economic regulation of pipelines (chapter 3) and consumer protections (chapter 7) for further discussion and issues for consultation.

Impact on heating values

Introducing hydrogen, and some other renewable gases, changes the amount of energy or heating value[123] delivered for any volume of blended gas delivered through a distribution system. Hydrogen is less dense than natural gas, at 0.0899kg/m^3 compared to 0.8kg/m^3 for natural gas. However, for any unit measure of mass, hydrogen has a much greater calorific value at 120-142 MJ/kg versus 42-55 MJ/kg for natural gas. The net result is that pure hydrogen delivers one third of the energy of natural gas for any given volume. Or 10.78 MJ per m3 of gas volume is delivered by hydrogen, and natural gas delivers 33.6 MJ per m3 of gas, at the higher heating value.

The heating value or calorific value (that is, energy per unit volume and energy per unit mass) of all types of renewable gases are shown in the table below. The impact of introducing hydrogen on the gas volume required to deliver the same energy from a renewable gas blend is shown in the subsequent table.

Table E.2: Natural gases and renewable gases overview

	NATURAL GAS	BIOGAS	BIO-METHANE	HYDROGEN	SYNTHETIC METHANE
Description	Naturally occurring hydrocarbon. Non-renewable	Anaerobic digestion of organic matter in oxygen free environment. Produced from waste. Renewable	Near pure methane from refining biogas using water scrubbing or membrane separation. Renewable	Clean combustible non-toxic gas that can be produced using fossil fuels or renewable energy.	Hydrogen and CO2 combined at high temperatures to produce pure methane and water.

122 As transmission pipelines are steel, this issue is particularly relevant to those pipelines.

123 Or calorific value, the total energy released as heat when a substance undergoes complete combustion with oxygen.

	NATURAL GAS	BIOGAS	BIO-METHANE	HYDROGEN	SYNTHETIC METHANE
		resource	resource		
Gas makeup	93-98% methane 3-5% ethane <1& CO2, 02, N2, H2, propane	55-65% methane 35-45% CO2 <1% O2, N2, H2, H2S, CO	94-99.9% methane 1-4% CO2 <1% O2, N2	100% H2 (Assuming purification)	97-99.9% methane <1% O2, N2, CO2
Heating (Calorific) Value (MJ/kg) (Energy per unit Mass)	42-55	15-30	50-55	120-142	50-55
Energy Density (MJ/L) (Energy per unit volume)	Uncompressed 0.0364 Compressed: 9	Slightly lower than natural gas	Uncompressed 0.0378 Compressed 9-9.5	Uncompressed 0.01-0.02 Compressed 4.5-5.3	Uncompressed 0.0378 Compressed 9-9.5
Density (kg/m3)	0.8	1.2	0.668	0.0899	0.8

Source: AEMC.

Table E.3: **Gas blends table**

METHANE AND HYDROGEN MIX		ENERGY CONTENT (MJ/M3)	ENERGY CONTENT RELATIVE TO PURE METHANE (%)	VOLUME OF GAS THROUGH METER (M3)	INCREASE IN VOLUME TO DELIVER THE SAME ENERGY (%)
METHANE (%)	HYDROGEN (%)				
100%	0%	33.60	100.00%	751.47	0.00%
99%	1%	33.37	99.32%	756.61	0.68%
98%	2%	33.14	98.64%	761.81	1.38%
97%	3%	32.92	97.96%	767.09	2.08%
96%	4%	32.69	97.28%	772.45	2.79%
95%	5%	32.46	96.61%	777.88	3.51%
94%	6%	32.23	95.93%	783.38	4.25%

METHANE AND HYDROGEN MIX		ENERGY CONTENT (MJ/M3)	ENERGY CONTENT RELATIVE TO PURE METHANE (%)	VOLUME OF GAS THROUGH METER (M3)	INCREASE IN VOLUME TO DELIVER THE SAME ENERGY (%)
METHANE (%)	HYDROGEN (%)				
93%	7%	32.00	95.25%	788.97	4.99%
92%	8%	31.78	94.57%	794.63	5.74%
91%	9%	31.55	93.89%	800.38	6.51%
90%	10%	31.32	93.21%	806.21	7.28%
80%	20%	29.04	86.42%	869.54	15.71%
70%	30%	26.76	79.63%	943.68	25.58%
60%	40%	24.48	72.84%	1031.63	37.28%
50%	50%	22.19	66.05%	1137.67	51.39%
40%	60%	19.91	59.26%	1268.00	68.74%
30%	70%	17.63	52.48%	1432.05	90.57%
20%	80%	15.35	45.69%	1644.87	118.89%
10%	90%	13.07	38.90%	1931.98	157.09%
0%	100%	10.79	32.11%	2340.51	211.46%

Source: AEMC.

Currently, heating values are not measured on an individual customer connection basis. As blends are introduced across distribution systems, the importance of knowing metering heating values more often and on more parts of the system (if not at an individual user level) grows. For example, a 10 per cent hydrogen blend would require approximately 7.28 per cent additional volumetric supply of gas. If the heating value is not accurately and frequently measured, the customer could be over billed for the amount of energy delivered.

E.3 Potential issues in the metering regulatory framework

As noted above and discussed in chapter 5, it is important that the energy content and volume of gas consumed is accurate. In order to ensure consumers are charged correctly when blended gas is supplied there are some key aspects of the metering arrangements that will need to be reviewed and potentially amended across the facilitated markets (DWGM and STTM) and regulated retail markets. The metering arrangements that may need amending include, but are not limited to:

- that existing gas chromatographs are tested and, if required, recalibrated, modified or replaced, to ensure they can measure the heating value of natural gas equivalents throughout the pipelines
- changes to the metering requirements in the NGR for the DWGM and STTM, the RMP, and relevant jurisdictional instruments to ensure that gas monitoring systems in distribution

systems can accurately measure the energy content of natural gas equivalents at different times and locations

- local heating values to be determined for specific parts of distribution systems and calculated more often than under current arrangements.

These issues largely fall within the scope of AEMO's review of its procedures.

In addition to issues impacting the metering of blended gas, there is also a question of whether it is distributors or retailers that are responsible for monitoring and managing the blend over time and across a distribution system. The allocation of responsibilities could be accounted for in the regulatory framework or in gas transportation contracts.

F LIST OF QUESTIONS

QUESTION 1: SCOPE OF THE REVIEW

1. Do you agree with the Commission's preliminary position on the scope of this review?
2. Are there additional areas in the NGR or NERR that should be excluded or included in the current review? If so, why?

QUESTION 2: ASSESSMENT FRAMEWORK

1. Do you agree with the Commission’s proposed assessment framework for this review?
2. Are there any criteria the Commission should or should not consider as a part of its assessment framework?

QUESTION 3: SUPPLIER ACCESS TO PIPELINES

1. Do you think that any additional guidance is required in the NGR to deal with connections by suppliers of natural gas equivalents or constituent gases, or are the new draft interconnection rules sufficient? If you think additional guidance is required, please set out what guidance you think is required.
2. Do you think service providers should be required to publish information on where connections by suppliers of natural gas equivalents or constituent gases would be technically feasible, or should this just be left to negotiations?
3. Do you think that any specific rules are required in the NGR to deal with the risk that service providers may favour their own natural gas equivalents or constituent gas facilities by curtailing other facilities ahead of their own, or do you think this should be dealt with through ring-fencing arrangements?

QUESTION 4: RING-FENCING ARRANGEMENTS

1. Do you think the ring-fencing exemptions in the NGR should be amended to accommodate trials by service providers? Why?
2. If so, do you think there should be any limit on the volume service providers should be able to producer, purchase or sell (e.g. up to the unaccounted for gas level)?

3. Do you think any other changes need to be made to the ring-fencing provisions in the NGL or NGR to accommodate natural gas equivalents or constituent gases?

QUESTION 5: RULES FOR SCHEME PIPELINES

1. Do you think Part 9 of the NGR should be amended to provide the regulator with additional guidance on how to assess service provider proposals to transition to natural gas equivalents in those cases where a jurisdiction does not mandate the transition? If so, please explain what changes you think need to be made and why.
2. Do you think Part 9 of the NGR should be amended to clarify how government grants or funding are to be treated for regulatory purposes?
3. Do you think any of the other rules that will apply to scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?

QUESTION 6: RULES FOR NON-SCHEME PIPELINES

1. Do you think the arbitration principles applying to non-scheme pipelines should be amended to:
    a. require the arbitrator to take into account any regulatory obligation that a pipeline may be subject to?
    b. provide the arbitrator with greater guidance on how to assess proposals by a service provider to transition to transporting a natural gas equivalent where the transition is not mandated?
    c. clarify how government grants are to be treated?
2. Do you think any of the other rules that will apply to non-scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?

QUESTION 7: PIPELINE GAS TYPE INFORMATION

1. Do you think service providers should be required to publish information on:
    a. The type of gas they are licensed to transport in their user access guides and, in the case of scheme pipelines, the access arrangement and access arrangement information? Why?

   b. Any firm plans to conduct either a trial or to transition the pipeline (or part of the pipeline) to a natural gas equivalent or other gas product? Why?
2. Do you think this information should also be reported on the AEMC's Pipeline Register?

QUESTION 8: EXTENSION OF THE TRANSPARENCY MECHANISMS TO NATURAL GAS EQUIVALENTS

1. Except for blending facilities are there any other facilities or activities involved in the supply or use of natural gas equivalents that are not already captured by:
   a. the BB facilities listed in rule 141 of Part 18 of the NGR?
   b. the DWGM registration categories in rule 135A of Part 15A of the NGR?
2. If the information to be reported by facilities involved in the production, transportation, storage, compression and or use of natural gas equivalents is to be based on the information reported by their natural gas counterparts, are any amendments required to reflect differences in the physical characteristics of these facilities compared to natural gas facilities for:
   a. the Bulletin Board reporting obligations in Part 18 of the NGR?
   b. the GSOO content in rule 135KB of Part 15D of the NGR?
   c. rules 323-324 in Part 19 of the NGR?
   d. the compression and storage reporting obligations in Part 18A of the NGR?
   e. the price information to be published by the AER in proposed rule 140B in Part 17 of the NGR?
3. Should blending facilities be treated as production facilities for the purposes of the Bulletin Board, GSOO and VGPR, or should specific reporting obligations be developed for these facilities? Why? If you think specific reporting obligations are required, what should these be?
4. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the five transparency mechanisms were to be extended to natural gas equivalents? Why? If you think there are other issues, what are they and what amendments are needed?

QUESTION 9: EXTENSION OF THE TRANSPARENCY MECHANISMS TO CONSTITUENT GASES

1. Do you think the following transparency mechanisms should be extended to the facilities and activities involved in the supply of constituent gases as part of the initial rules package or should the application of one or more be deferred until a later process? Why?
    a. the Bulletin Board
    b. the GSOO
    c. the VGPR
    d. the compression and storage terms and prices
    e. the AER's gas reporting functions.
2. If you think the transparency mechanisms should be extended as part of the initial rules package:
    a. What facilities do you think need to be captured?
    b. Do you think the facilities and activities involved in the supply of constituent gases should be subject to equivalent reporting obligations as their natural gas counterparts, or are some modifications required to reflect differences in the physical characteristics of these facilities?
3. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the transparency mechanisms were to be extended to constituent gases? Why? If you think there are other issues, what are they and what amendments are needed?

QUESTION 10: TRADING NATURAL GAS EQUIVALENTS IN THE FACILITATED MARKETS

1. Do you think natural gas equivalents should be traded through the facilitated markets, or outside of the facilitated markets?
2. What do you consider are the implications of these two options, in terms of required regulatory changes, costs of implementation and potential market inefficiencies?

QUESTION 11: FACILITATED MARKET REGISTRATION CATEGORIES

1. If natural gas equivalents are to be integrated into the facilitated markets, are new registration categories required to accommodate facilities and participants involved in the creation of these products, including through the injection of blends into the distribution system?

2. If flows associated with distribution-connected blending facilities are not scheduled in facilitated markets, are new registration categories required for blending facilities and associated participants or can they be exempted from registration?

QUESTION 12: UNACCOUNTED FOR GAS IN THE FACILITATED MARKETS

1. Do you think initial trials involving the injection of natural gas equivalents into the distribution system should be accommodated by amending jurisdictional arrangements for UAFG?
2. If so, how will this impact the operation of the matched allocation mechanism (as used by the distributor in the Sydney STTM hub)?
3. What changes would be required to UAFG arrangements in the DWGM?

QUESTION 13: SETTLEMENT ISSUES IN THE FACILITATED MARKETS

1. If distribution connected blending facilities are not integrated into the facilitated markets, what settlement issues may arise?
2. If distribution injections and corresponding end use consumption need to be excluded from settlement, how should excluded consumption be treated? What factors might affect this?
3. If distribution connected blending facilities are integrated into the facilitated markets, are settlement issues in the STTM likely to be relatively straightforward to resolve? Why?
4. How should facilities exempted from registration, or that fall below a materiality threshold, be treated under settlement arrangements in the facilitated markets?

QUESTION 14: METERING AND HEATING VALUES IN THE FACILITATED MARKETS

1. Does the NGR restrict distributors' ability to calculate heating values in different parts of the distribution system to accommodate the different uses of natural gas equivalent gases in the facilitated markets?
2. Are amendments required to the NGR to facilitate the determination of more granular heating values and any other matters relating to the metering provisions for the DWGM?

QUESTION 15: GAS SPECIFICATION IN THE FACILITATED MARKETS

1. In relation to the STTM, do you think Part 20 of the rules should be amended to clarify that AS 4564 – 2005 can be augmented or replaced to accommodate blending in certain parts of STTM distribution systems? Are any other changes required, including to accommodate impacts on connected transmission pipelines?
2. In relation to the DWGM, do you think Part 19 of the rules should be amended to give AEMO (or another party) the ability to directly determine the gas specification on distribution systems?

QUESTION 16: BLENDING CONSTRAINTS IN THE FACILITATED MARKETS

1. Who should be responsible for the creation of natural gas equivalent blends and ensuring that these remain consistent with a revised gas specification?
2. In the DWGM, should AEMO be given operational control over the distribution system to manage blending constraints? If so, what changes to the rules would be required?

QUESTION 17: OTHER IDENTIFIED ISSUES IN THE FACILITATED GAS MARKETS

1. Do the identified issues in the NGR and changes required cover all necessary changes to facilitate the trade of natural gas equivalents in the DWGM and STTM?
2. Are there any other issues the Commission should be aware of?
3. Are all of these changes required now for natural gas equivalents? Could some of these changes be made at a later date, or when other gas products are taken into consideration?
4. Are there any transitional issues?

QUESTION 18: INITIAL IDENTIFIED ISSUES IN THE REGULATED RETAIL MARKETS

1. Are changes to the retail market registration provisions required to accommodate natural gas equivalents?

2. Are there any other changes required to the retail market provisions in the NGR to accommodate natural gas equivalents?

QUESTION 19: OTHER POTENTIAL ISSUES IN THE REGULATED RETAIL MARKETS

1. Are there any issues the AEMC should consider in relation to the recovery of the cost of the renewable component of the natural gas equivalent from retail customers, for a natural gas equivalent?
2. Are there any issues the AEMC should consider in relation to retail competition and consumer choice as a consequence of the introduction of natural gas equivalents?
3. How are these issues impacted by jurisdictional policies in relation to mandated renewable gas targets or mandated green value in a gas stream? Are any changes to the NGR and NERR needed, either now or in the near future, to address any concerns about competition, consumer choice and cost pass through of renewables in the retail market.

QUESTION 20: CONSUMER PROTECTION FRAMEWORK

1. Do you consider that changes are required to the consumer protection framework to reflect the physical properties of natural gas equivalents compared to natural gas? Specifically:
    a. Should retailers be required to notify existing customers prior to the transition from the supply of natural gas to a natural gas equivalent that the customer is now being supplied with the natural gas equivalent and the changes the customer may see in relation to the quantity of gas metered at their premises following the transition?
    b. Should the model terms and conditions for standard retail contracts and the minimum requirements for market retail contracts be amended to make clear if the supply of gas under that contract is a supply of natural gas or a natural gas equivalent?
    c. Should retailers who receive requests for historical billing data from a customer be required to state in the billing information provided if there was a transition from natural gas to a natural gas equivalent during the billing history period for which information is requested, and the date at which the transition occurred?
    d. If the natural gas equivalent to be supplied has a different heating value from natural gas, should there be a requirement for retailers to issue a bill based on an actual meter read for customers with accumulation (non-interval) meters before supply is transitioned to a natural gas equivalent?
2. Are there any other gaps in the consumer protection framework that arise because of the difference in the physical properties of natural gas and natural gas equivalents?
3. Do you consider that customers should be informed if price variations occur because of the transition to natural gas equivalents?
4. How should the risks of 'off spec' natural gas equivalents be allocated under the NERL and NERR? Is the existing allocation of risk for the quality of natural gas appropriate if

distributors have responsibility for creating the natural gas equivalent (for example, through the operation of blending facilities)? What is the appropriate mechanism for managing loss suffered by customers as a result of 'off spec' natural gas equivalents?

QUESTION 21: REGULATORY SANDBOX ARRANGEMENTS

1. Is it practicable for a retail customer to opt out of a change of product trial? If not:
   a. should the definition of explicit informed consent be required to provide information that the customer is unable to opt out of the trial for the period of the trial?
   b. should the AER have power to extend a change of fuel trial if retail customers cannot practicably opt out of the trial?
2. Are any changes to the consultation requirements regarding proposed trial waivers for change of product trials needed? For example, on the AER public consultation requirements for change of product trials.
3. Should amendments be made to specify certain pre-conditions to the granting of a trial waiver for a change of product trial involving the sale and supply of an 'other gas product'? If so:
   a. should the applicant be required to provide this approval as part of its application for a trial waiver?
   b. should the rule change proponent for a trial rule be required to provide this approval as part of its request for the rule?
4. Are there any other gaps that would arise in the proposed regulatory sandbox framework if it is extended to natural gas equivalents, other gas products and constituent gases?

G TERMS OF REFERENCE

Australian Government
Department of Industry, Science, Energy and Resources

Ms Anna Collyer
Chair
Australian Energy Market Commission
GPO Box 2603
SYDNEY NSW 2001

Dear Ms Collyer

As you are aware, Energy Ministers have agreed to amend the national gas regulatory framework to accommodate hydrogen and renewable gas blends, such as biogas. These reforms have been identified as a priority in the context of the National Hydrogen Strategy.

Energy Ministers have agreed that it is appropriate for an independent review of potential gaps in the national gas regulatory framework arising out of amendments to cover hydrogen and renewable gas blends and for the AEMC to develop the initial rules required to accommodate these blends under an amended framework.

This review has been identified as a priority because a number of blending trials and larger blending projects are in development, with the first large projects expected to begin blending by early 2023. There is therefore a degree of 'catch up' that needs to occur to ensure that consumers, gas pipeline service providers and other market participants are not exposed to material risks and the application of the regulatory framework in the context of gas blends is clear. This review should have regard to a review that was conducted as an action of the National Hydrogen Strategy, which has identified potential gaps within the national gas regulatory framework.

Pursuant to section 79 of the National Gas Law and section 228 of the National Energy Retail Law, Energy Ministers request that the AEMC conduct a review of those elements of the national gas regulatory framework that may be affected by the supply of hydrogen and renewable gas blends and report back to Energy Ministers with the initial rules by November 2022. In conducting this review, the AEMC will be expected to work closely with the other market bodies, which are also being tasked to undertake reviews to support the proposed reforms, and officials who are progressing legislative reforms to bring these blends into the framework. The AEMC will also be expected to consult with industry and other stakeholders as appropriate on the draft initial rules. The attached Terms of Reference sets out the purpose, scope and timeframe for this review.

I thank you for undertaking the review at this time. If your staff wish to discuss the review further, please contact David Gourlay, the manager of the Renewable Gas section in my Department at david.gourlay@industry.gov.au or call (02) 6243 7485.

Sincerely

Mr Sean Sullivan
Chair
Energy Senior Officials
24 August 2021

Attachment A

Review of the National Gas and Retail Regulatory Frameworks for the introduction of hydrogen and renewable gas

Terms of Reference

Background

Energy Ministers have agreed to reform the national gas and retail regulatory frameworks to accommodate hydrogen, biomethane and other renewable gas blends ("gas blends"). These reforms have been identified as a priority in the context of the National Hydrogen Strategy.

The purpose of these reforms is to bring renewable gases and gas blends within the national gas and retail regulatory frameworks. Energy Ministers have agreed that expedited reforms will focus on 'low-level' gas blends, such as those that can be safely supplied through existing gas networks. This will include low level hydrogen blends, biomethane and other renewable gases that can be substituted for natural gas (e.g. synthetic methane).

A desktop review of the national gas regulatory framework completed as an action of the National Hydrogen Strategy in 2020-21 found that if these blends were brought into the framework, most elements of the current framework could apply to these blends in the same way they apply to natural gas. The review did, however, find that a small number of gaps could potentially emerge that could affect some elements of:

- the economic regulatory framework applying to gas pipelines
- the facilitated and regulated retail gas markets
- the consumer protections provided for under the NERL and NERR
- the regulatory sandbox that is currently being implemented.

To address these gaps amendments to the National Gas Law (NGL), National Gas Rules (NGR), National Gas Regulations (Regulations), National Energy Retail Law (NERL), National Energy Retail Rules (NERR) and other subordinate instruments that form part of the national gas and retail regulatory frameworks will be required.

Energy Ministers therefore request that the Australian Energy Market Commission (AEMC) review matters falling within its area of responsibility, with a view to addressing these gaps for low level hydrogen blends, biomethane and other renewable gases that can be substituted for natural gas (e.g. synthetic methane).

Gaps in the national framework that could emerge as a result of the supply of higher level hydrogen blends and 100 per cent hydrogen will not be considered in this review process. These may be considered in a separate review at a later date, subject to a future request from Energy Ministers.

Australian Government

Department of Industry, Science, Energy and Resources

Energy Ministers' Directed Review

Pursuant to section 79 of the NGL and section 228 of the NERL, Energy Ministers[1] request the AEMC conduct a review of the proposed changes to the national gas and retail regulatory frameworks in accordance with these Terms of Reference.

These Terms of Reference, which have been developed in accordance with section 80 of the NGL and section 229 of the NERL, are intended to guide how the AEMC undertakes this review.

Purpose

The purpose of this review is to advise Energy Ministers on the initial rules required in the national gas and retail regulatory frameworks to accommodate low level hydrogen blends and renewable gases, and advise on any changes to the law required to enable these rules.

Scope

In undertaking the review, the AEMC is requested to:

- Have regard to the findings of the desktop review that was conducted for DISER as the starting point for the identification of potential gaps in the NGR and NERR that could emerge if low level hydrogen and renewable gas blends are permitted to be supplied through gas distribution networks
- Consult with market participants, industry, consumers, other market bodies and government officials, as appropriate, to identify any other material gaps in the NGR and NERR
- Develop the initial rules that are required to address the identified gaps in the NGR and NERR, and consult on the draft initial rules
- Advise officials working on the legislative reforms of any gaps in the NGL and NERL identified by the AEMC in its review of the rules.

The matters that the AEMC is asked to specifically consider are:

- The economic regulatory framework, including:
  - Connection and access by facilities for the production, injection and blending of hydrogen, biogas and other renewable gases into distribution networks (and other facilities as necessary) to ensure that:
    - access for these facilities is available on reasonable terms;
    - these facilities are covered by the dispute resolution provisions; and
    - hydrogen blending facilities only connect in parts of the network suitable for the injection of hydrogen; and
  - Ensure that any cap on the level of blending that may be set by a jurisdiction is implemented consistently in the regulatory framework.
- The facilitated markets and regulated retail markets, including:
  - address any matters that AEMO identifies in its review of the NGR, AEMO made Procedures and other AEMO made subordinate instruments that are required to ensure that settlement

[1] The Energy Ministers are those responsible for energy matters all of whom are members of the legally enduring Ministerial Council on Energy (MCE).

and metering in the Short-Term Trading Markets (STTM), the Victorian Declared Wholesale Gas Market (DWGM) and regulated retail markets operate as intended
    - registration categories for the STTM, the DWGM and/or regulated retail markets; and
    - responsibility for creation of the blend (as between distributors and retailers) and whether and how that should be accounted for in the regulatory framework.
- The NERR and whether any additional consumer protections may be required, such as provision of information to customers and any minimum contract terms or bill content requirements.
- The regulatory sandbox provisions in the national gas and retail regulatory frameworks.
- Any other material aspects of the NGR and NERR necessary to support low-level gas blends under the regulatory framework.

Governance, consultation and timeframe

The Energy National Cabinet Reform Committee agreed on 11 June 2021 that these reforms should be expedited as a number of hydrogen and biomethane blending projects are proposed.

To expedite these reforms, Energy Ministers request that the AEMC conduct this review in parallel with the reviews that are to be conducted by AEMO, the AER, the ERA and legislative reforms led by officials to accommodate hydrogen and renewable gases into the national gas and retail regulatory frameworks.

Energy Ministers request that the AEMC work with AEMO, the AER, the ERA and officials to align these parallel processes and to share information, findings and resources as necessary. Energy Ministers also request that the AEMC participate in a project team that will comprise market bodies and officials working on these processes to facilitate collaboration and to report on progress to Senior Officials through its Gas Working Group.

The AEMC must conduct public consultation on this review that, where possible, should be conducted alongside public consultation for the other related processes.

The AEMC is requested to:

- Inform Senior Officials of its views on any required changes to the NGL and NERL and the prioritisation of any identified gaps, so that these can be reflected in the legislation to be prepared by Officials and legislative amendments can be provided to Energy Ministers for agreement by mid-2022.
- Publish a draft report that reflects public consultation and sets out the AEMC's draft recommendations on the initial rules and a first draft of the initial rules.
- Publish a final report that sets out the AEMC's final recommendations and its proposed draft initial rules that reflect the final recommendations.
- Consult on its proposed draft initial rules and report back to Energy Ministers by November 2022, with a final set of initial rules that can be made by the SA Minister once the required changes to the legislation are made.