Framework for the consistent reporting of natural gas reserves and resources

ACCC recommendations

May 2019

Contents

Glossary

Term	Meaning
1P reserves	Means proved reserves
2P reserves	Means the sum of proved and probable reserves
3P reserves	Means the sum of proved, probable and possible reserves
1C resources	Means a low estimate of contingent resources
2C resources	Means the best estimate of contingent resources
3C resources	Means the high estimate of contingent resources
acquisition	Means the gaining of an interest in a gas field
approved for development	Has the meaning given in the PRMS – that is, all necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way
basin	Means a large geological area holding a thick accumulation of sedimentary rock
coal seam gas field	Means a gas field primarily comprised of gas contained in coalbeds
contingent resources	Has the meaning given in the PRMS – that is, those quantities estimated to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable due to one or more contingencies
conventional gas field	Means a gas field primarily comprised of gas contained in relatively porous and permeable sedimentary rocks such as sandstone and limestone. Compared to unconventional gas fields, relatively little intervention is required to promote gas flow and relatively few wells are required to produce gas over the life of the field.
deterministic method	Has the meaning given in the PRMS – that is, a method based on discrete estimate(s) corresponding to a given level of certainty, made based on available geoscience, engineering, and economic data
developed reserves	Has the meaning given in the PRMS – that is, the quantities expected to be recovered from existing wells and facilities
development pending	Has the meaning given in the PRMS – that is, a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future
development on hold	Has the meaning given in the PRMS – that is, a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay
development unclarified	Has the meaning given in the PRMS – that is, a discovered accumulation where activities are under evaluation and where justification as a commercial development is unknown based on available information
development not viable	Has the meaning given in the PRMS – that is, a discovered accumulation for which there are no current plans to develop or to acquire additional data because of limited production potential
discoveries	Means the discovery of new gas fields, or new reservoirs in existing gas fields

divestment	Means disposal of an interest in a gas field
dry gas field	Means a field that primarily comprises of dry gas (that is natural gas. without condensates or liquid hydrocarbons)
extensions	Means changes in reserves in a gas field resulting from the enlargement of the proved area
gas condensate field	Means a gas field primarily comprised of gas condensates or liquid hydrocarbons
gas field	Means an area consisting of one or more reservoirs over which the right to explore for, extract, recover or process petroleum has been granted
justified for development	Has the meaning given in the PRMS – that is, the project is justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals and contracts will be obtained
material change	Means a change of 50 PJ or more in a producer's reserves or 2C resources across the producer's east coast and Northern Territory portfolio
materiality threshold	Means the threshold above which a gas field is considered material for the purpose of the requirement to report on development status under section 2.1.5 of this framework
net revenue interest	Has the meaning given in the PRMS – that is, a revenue share of petroleum sales, after deduction of royalties or share of production owing to others under applicable lease and fiscal terms
oil field (with associated gas)	Means an oil field that also contains natural gas within the same reservoir
on production	Has the meaning given in the PRMS – that is, the project is currently producing, or capable of producing, and selling
PRMS	Means the Petroleum Resources Management System developed by the Society of Petroleum Engineers (SPE)
possible reserves	Has the meaning given in the PRMS – that is reserves that analysis of geological and engineering data suggest are less likely to be recoverable than Probable Reserves. The quantity actually recovered has a low probability of exceeding the 3P Reserves estimate. If probabilistic methods are used, there should be at least a 10 per cent probability that the quantities actually recovered will equal or exceed the 3P Reserves estimate. For the avoidance of doubt, Possible Reserves should be the upside quantities to the 2P scenario.
probabilistic method	Has the meaning given in the PRMS – that is, a method in which the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities
producers	Holders of gas reserves and resources, including entities currently producing gas and those that are not currently producing but have an interest in gas reserves and/or resources
prospective resources	Has the meaning given in the PRMS – that is, those quantities estimated to be potentially recoverable from undiscovered accumulations by the application of future development projects
proved reserves	Has the meaning given in the PRMS – that is, reserves that analysis of geological and engineering data suggest are reasonably certain to be commercially recoverable. If deterministic methods are used, the term

	“reasonably certain” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 per cent probability that the quantities actually recovered will equal or exceed the 1P Reserves estimate.
probable reserves	Has the meaning given in the PRMS – that is, reserves that analysis of geological and engineering data suggest are less likely to be recoverable than Proved Reserves but more likely to be recoverable than Possible Reserves. It is equally likely that the quantities actually recovered will be greater than or less than the 2P Reserves estimate. If probabilistic methods are used, there should be at least a 50 per cent probability that the quantities actually recovered will equal or exceed the 2P Reserves estimate.
reserves	Has the meaning given in the PRMS – that is, those quantities of gas that are expected to be commercially recoverable
sales quantities	Has the meaning given in the PRMS – that is, those quantities available for sale after excluding the gas consumed, flared or lost in operations
SEC	Means the US Securities and Exchange Commission
unconventional gas field	Means a gas field primarily comprised of gas contained in sedimentary rocks with relatively low porosity and permeability. Compared to conventional gas fields, relatively more intervention is required to promote gas flow and a relatively high number of wells may be required over the life of the field. The International Energy Agency categorises the three major types of unconventional gas as: • shale gas: natural gas contained within shale rock • coal seam gas (CSG): natural gas contained in coalbeds • tight gas: natural gas found in low permeability rock formations. Other unconventional gas types include, basin centred gas, deep coal gas and syngas.
undeveloped reserves	Has the meaning given in the PRMS – that is, the quantities expected to be recovered through future significant investments. This includes reserves to be produced: from new wells on undrilled acreage in known accumulations; from deepening existing wells to a different but known reservoir; from infill wells that will increase recovery; or where a relatively large expenditure is required to complete an existing well or install production or transportation facilities for primary or improved recovery projects.

1. Introduction

1.1. Background

The ACCC's 2015 East Coast Gas Inquiry (2015 Inquiry) found that the gas market was not signalling expected supply problems effectively, and noted a lack of transparency around the reporting of gas reserves and resources. In particular, the 2015 Inquiry found that public information on reserves and resources was fragmented and reported inconsistently, making it of limited use to gas market participants and policymakers. The ACCC therefore recommended that all producers[1] be required to publish reserve and resource information on the Natural Gas Services Bulletin Board (Bulletin Board) using a consistent reporting framework and common gas price assumptions.[2]

The need for greater transparency and consistent reporting of reserves and resources estimates and the assumptions underpinning those estimates has been reinforced through the ACCC's 2017-2020 Gas Inquiry (current Inquiry).[3] To this end, the ACCC and the Gas Market Reform Group (GMRG)[4] recently recommended to the Council of Australian Governments (COAG) Energy Council that:[5]

- producers be required to report information on their reserves and resources and the volume of contracted reserves
- the information be reported to the Australian Energy Market Operator (AEMO) for publication on the Bulletin Board, using the reporting framework to be developed by the ACCC in 2019.[6]

In keeping with the latter of these recommendations, the ACCC published a consultation paper on the proposed reporting framework on 19 February 2019. The consultation paper set out the objectives of the reporting framework (see box 1.1) and the ACCC's initial views on the following elements of the reporting framework:

(a) the reserves and resources information that producers would be required to report

(b) the bases on which reserves and resources information would have to be reported

(c) the manner in which producers would be required to estimate reserves (including the gas price assumptions to be used in the estimation and associated disclosure requirements).

In total, 17 submissions were received in response to the consultation paper. Nine submissions were received from producers (APLNG, Arrow, Chevron, Cooper Energy, Esso, Origin, Santos, Senex and Shell), two were received from retailers (AGL and EnergyAustralia) and one was received from a major gas user (Australian Paper). The remainder were received from Geoscience Australia, Australian Petroleum Production & Exploration Association (APPEA), the Energy Users Association of Australia (EUAA), Chemistry Australia and Lewis Grey Advisory.

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1 The term 'producers' is used throughout this paper to refer to holders of gas reserves and resources. It therefore includes entities that are currently producing gas and explorers that have an interest in gas reserves and/or resources.

2 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 13.

3 ACCC, *Gas Inquiry 2017-2020 Interim report*, December 2018, ch. 2.

4 This joint work was carried out in accordance with the Prime Minister's March 2017 direction that the two work together to *"…advise on options to quickly improve transparency in the gas market, to facilitate competition between producers and information for purchasers. The scope will include the full supply chain – producers, transporters, retailers*." (Hon. M Turnbull MP, *Measures agreed for Cheaper, More Reliable Gas*, 15 March 2017.)

5 These recommendations were set out in a report entitled, *Measures to improve the transparency of the gas market*.

6 ACCC and GMRG, *Joint recommendations: Measures to improve the transparency of the gas market*, December 2018.

Following the publication of the consultation paper, the ACCC also had discussions with government agencies and independent advisors, the latter including individuals significantly involved with the Petroleum Resources Management System (PRMS) 2018 update.

Box 1.1: Objectives of the reserves and resources reporting framework

The objectives of the reserves and reporting framework, which are consistent with the National Gas Objective[7] in the National Gas Law,[8] are to:

- provide market participants and policymakers with a better understanding of the supply outlook and, in so doing, enable more informed and efficient consumption, exploration, production, infrastructure investment and upstream policy decisions to be made
- signal changes to the supply outlook and potential supply shortfalls in a more timely and effective manner and, in so doing, enable the market to respond more efficiently to changing market conditions and reduce market volatility
- reduce the information asymmetry between gas suppliers and users and, in so doing, enable users to negotiate more effectively when entering into gas supply agreements (GSAs).

1.2. Summary of final recommendations

Having regard to the feedback provided by stakeholders and the objectives set out in box 1.1, the ACCC has developed its final recommendations on the reserves and resources reporting framework. These recommendations are summarised in table 1.1.

Before examining this table, it is worth noting that it excludes information on contracted reserves because the ACCC is now recommending that this information be collected and reported on in the Gas Statement of Opportunities (GSOO) rather than on the Bulletin Board (see section 2.1.6 for more detail).

[7] The National Gas Objective is set out in section 23 of the National Gas Law and states the following:

'The objective of this law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas'.

[8] *National Gas (South Australia) Act 2008.*

Table 1.1: Final recommendations on reporting framework

<table>
<tr><th colspan="4">Information to be reported</th></tr>
<tr><td rowspan="2">Reserves (reported by field)</td><td>1P (proved reserves)</td><td>2P (proved plus probable reserves)</td><td>3P (proved plus probable plus possible)</td></tr>
<tr><td colspan="3">Broken down (at a field level) into developed and undeveloped reserves</td></tr>
<tr><td>Resources (reported by field)</td><td colspan="3">2C (best estimate)</td></tr>
<tr><td>Gas field information</td><td colspan="3">The following information must be reported for each of the fields in which reserves and resources are located:
The development status (measured using the PRMS project maturity sub-classes) and likely timing of production for 2P reserves and 2C resources in fields that meet the materiality threshold (i.e. fields with more than 50 PJ of reserves or contingent resources) and a list of any barriers to the commercial recovery of 2C resources in these fields.
The type of gas contained in the field (e.g. conventional natural gas, coal seam gas, or another type of unconventional gas).
The nature of the gas field (e.g. a dry gas field (mostly methane), a gas condensate field (mainly condensates or liquid hydrocarbons), or an oil field (where gas is found associated with oil)).
The location of the field, the permit number associated with the field and the producer’s net revenue interest in the field (measured as a percentage).</td></tr>
<tr><td>Movements in 2P Reserves (reported by field)</td><td colspan="3">Annual movements in 2P reserves, broken down (at a field level) into: production, extensions, net acquisitions, reserve upgrades, reserve downgrades and other revisions.</td></tr>
<tr><th colspan="4">Bases upon which information is to be reported</th></tr>
<tr><td>Reporting standard</td><td colspan="3">Classification of reserves and resources and the definition of key terms used in the reporting framework, such as “1P”, “2P”, “3P”, “2C”, “developed reserves”, “undeveloped reserves”, “sales quantities”, “net revenue interest”, project maturity sub-classes, “reasonable expectations” and estimation methods to be based on the PRMS definitions.</td></tr>
<tr><td>Quantities to be reported and estimation methods</td><td colspan="3">Reserves and resources estimates to be based on the producer’s net revenue interest in the sales quantities of gas (measured in PJ) from all gas containing fields. Producers must also disclose the method(s) used to develop their estimates and the conversion factor used to convert quantities measured in trillions of cubic feet to petajoules.</td></tr>
<tr><td>Reporting level</td><td colspan="3">Reserves and resources estimates (including annual movements in 2P reserves) to be reported at a field level.</td></tr>
<tr><td>Reporting frequency</td><td colspan="3">Producers to report information to AEMO on an annual basis. Producers to also provide intra-year updates to the reserves or 2C resources estimates (including an explanation for any revisions) to AEMO if:
the producer provides revised reserves or resources estimates to the ASX, a government agency, or in a public statement
there is a material change (i.e. a change of 50 PJ or more in a producer’s reserves or 2C resources) in a producer’s reserves or resources estimates arising as a result of an acquisition/divestment,</td></tr>
</table>

		a re-evaluation of reserves and resources and/or discoveries of new reserves and resources.
Evaluation requirements		Reserves and resources estimates to be prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator, and if the evaluator is an employee this must be disclosed. The AER to have the power to require a producer to retain an independent petroleum reserves and resources evaluator to conduct an audit of their reserves and resources estimates and publish the outcome of the audit.
Reserves estimation requirements		
Manner in which reserves and resources are to be estimated		Reserves and resources to be estimated on the basis of forecast economic conditions, and producers to disclose the key economic assumptions underpinning their reserves and resources estimates and the source of these assumptions.
Gas price assumptions	**Contracted reserves**	Producers to use the prices specified in the relevant gas supply agreements (GSA) for contracted reserves, including taking account of the operation of: • the price escalation mechanisms specified in the relevant GSAs over the forecast period • contract extension provisions specified in the relevant GSAs over the forecast period, if there is a reasonable expectation that the GSAs will be extended and the prices (or pricing mechanisms) to apply in the extension period have already been determined.
	Uncontracted reserves	Producers to determine the forecast gas prices used in the estimation of uncontracted reserves, and to: have the price assumptions verified by a suitably qualified independent petroleum reserves and resources evaluator as falling within the range of gas price forecasts used or adopted by such evaluators, or published by reputable independent Australian sources of gas industry forecast information for Australia report their actual gas price assumptions to the AER (along with a description of how the assumptions were derived), so that the AER can oversee compliance with this requirement and publish anonymised and aggregated information on the gas prices assumed by producers report on the sensitivity of their 2P reserve estimates to a +/-10 per cent change in their gas price assumption to AEMO for publication on the Bulletin Board in an anonymised and aggregated manner.

Consistent with the objectives set out in box 1.1, the ACCC's recommendations on the reporting framework are expected to provide more economically efficient investment signals by providing market participants and policymakers with a better understanding of the supply outlook, signalling changes to the outlook in a more timely and effective manner, and reducing the information asymmetry faced by gas users. It will do so by providing for a greater level of transparency and consistency of reporting of:

- The commercially recoverable quantities of gas that could be supplied to the market and the uncertainty surrounding these quantities; transparency in this case will be provided through the publication of:
  - 1P, 2P and 3P reserve estimates
  - the breakdown of these estimates into 'developed' and 'undeveloped' reserves
  - the gas field information (i.e. the type of gas in the field and the nature of the field)

    - information on whether the 2P reserves in fields that satisfy the materiality threshold are on production, approved for development or justified for development.
- The potentially recoverable quantities of gas and the uncertainty surrounding these quantities; transparency in this case will be provided through the publication of:
    - 2C resource estimates
    - the gas field information (i.e. the type of gas in the field and the nature of the field)
    - information on whether the development of 2C resources in fields is pending, on hold, unviable or unclarified.
- Developments in fields that meet the materiality threshold and the risks and uncertainties surrounding these developments; transparency in this case will be provided through the publication of information on:
    - the development status of these 2P reserves and 2C resources (determined using the PRMS project maturity sub-classes)
    - when production is likely to commence for these 2P reserves and 2C resources
    - the barriers to the commercial recovery of 2C resources in these fields.
- The performance of each field and the drivers of change in 2P reserves in those fields; transparency in this case will be provided through the publication of information on annual movements in 2P reserves arising as a result of production, extensions, net acquisitions, reserves upgrades and downgrades, and other revisions.
- Gas price assumptions and the sensitivity of 2P reserves estimates to these assumptions; transparency in this case will be provided through the publication of aggregated and anonymised data on the gas price assumptions underpinning producers' uncontracted reserves and resources estimates and the sensitivity of their 2P reserve estimates to a +/-10 per cent change in this assumption.

In developing these recommendations, the ACCC has sought to minimise the regulatory burden and compliance costs highlighted, in particular, in submissions from APPEA, Shell and Esso, whilst also ensuring that the reporting framework is fit for purpose, targeted and proportionate to the issues it is intended to address. The ACCC has, for example, recommended:

- limiting the reporting requirements for resources to 2C resources
- the adoption of a materiality threshold for the obligation to report on the development status of 2P reserves and 2C resources and associated information
- that producers be responsible for determining when they submit their annual reserves and resources information to AEMO and to limit the circumstances in which producers will be required to report intra-year changes to their reserves and resources estimates
- the replacement of the requirement for an independent evaluator to be involved in reserve and resource evaluations with the inclusion of a power for the AER to require an independent audit of a producer's reserves and resources estimates to be conducted.

Producers' reporting costs could be further reduced if this framework was employed by other government agencies. The ACCC therefore recommends that the COAG Energy Council undertake a review of existing state and territory reporting frameworks and proceed to amend or vary those frameworks to be consistent with this reporting framework. Apart from reducing compliance costs and the regulatory burden faced by producers, the adoption of a single reporting framework in Australia will ensure reserves and resources are reported to the market in a consistent manner.

Box 1.1: Bulletin Board

The Bulletin Board, which is operated by AEMO, is underpinned by the legal framework set out in:

- Chapter 7 of the National Gas Law (NGL): The NGL requires persons of a kind specified in the NGL to provide AEMO with information for publication on the Bulletin Board, if required to do so under the NGR and also states that a person:
  - cannot rely on a duty of confidence to avoid compliance with the obligation to provide AEMO with information
  - must not give AEMO information they know is false or misleading in a material particular.

  The NGL also accords the AER responsibility for monitoring and enforcing compliance with the reporting obligations.
- Part 18 of the National Gas Rules (NGR): The NGR sets out the information to be reported to AEMO for publication on the Bulletin Board, the standard that this information must comply with and the timing of the reporting.
- Schedules 3 and 4 of the National Gas Regulations: The Regulations identify those obligations that are civil penalty provisions and those that are conduct provisions.
- AEMO issued Bulletin Board Procedures: The Procedures provide further detail on the information to be reported and the timing for reporting.

Under the NGL, the enforcement tools that the AER could employ if a producer failed to comply with the disclosure requirements and reporting framework will depend on whether the obligations are classified as a civil penalty provision. If they are not classified in this way, the AER can only: seek an administrative resolution, which may include a voluntary commitment to rectify non-compliance; or institute civil proceedings in the Federal Court and seek an injunction or an order that the person cease or remedy the conduct. If, however, they are classified as civil penalty provisions, then the AER would also be able to issue an infringement notice, or institute civil proceedings in the Federal Court seeking an order that the penalty be paid.

The current maximum civil penalty for failing to provide information to AEMO for publication on the Bulletin Board,[9] for providing information that is false or misleading information,[10] or for failing to comply with the Bulletin Board information standard,[11] is $100 000 for body corporates ($20 000 for individuals) plus $10 000 ($2000) for every day it continues.[12] The ACCC-GMRG have recently recommended that SCO consider increasing penalties for each breach of the Bulletin Board reporting obligations to:

- $1 million for body corporates
- $200 000 for individuals.

1.3. Next steps

The development of the reporting framework is, as noted above, part of a broader recommendation by the ACCC and GMRG that producers be required to report their reserves and resources to AEMO, for publication on the Bulletin Board.

The ACCC understands that the COAG Energy Council's Senior Committee of Officials (SCO) intends to consult on these proposed reporting obligations in 2019 and to then provide its final recommendations to the COAG Energy Council. As part of this process, SCO will also be consulting on the changes to the National Gas Law (NGL), the National Gas Rules (NGR)

[9] This obligation is set out in section 223 of the NGL.

[10] This obligation is set out in section 225 of the NGL.

[11] This obligation is set out in rule 165 of the NGR.

[12] See sections 3, 223 and 225 of NGL.

and other subordinate instruments that would be required to give effect to these recommendations and the reporting framework.

If the COAG Energy Council agrees to implement the reporting obligations and reporting framework, then, in a similar manner to other Bulletin Board reporting obligations, the Australian Energy Regulator (AER) will become responsible for monitoring producers' compliance with the obligations and the reporting framework (see box 1.1 for more detail).

1.4. Structure of paper

The remainder of this paper is structured as follows:

- Section 2 provides an overview of the feedback stakeholders provided on the reserves and resources information to be reported and the bases on which it is to be reported, and the ACCC's final recommendations on these two aspects of the reporting framework.
- Section 3 provides an overview of the feedback stakeholders provided on how reserves and resources are to be estimated (including the gas price assumptions to be used in the estimation and associated disclosure requirements), and the ACCC's final recommendations on this aspect of the reporting framework.
- Appendix A provides an overview of the reporting frameworks employed by other Australian and international agencies.
- Appendix B sets out how the ACCC envisages the reserves and resources information would be reported under this framework.
- Appendix C contains a list of the submissions that were received. These submissions will be published on the ACCC's website (subject to any legal restrictions) at the time this paper is published.

2. Information to be reported and reporting bases

In the 2015 Inquiry, the ACCC found that there was limited publicly available information on reserves and resources and, where that information was available, it was reported in a fragmented and inconsistent manner. The ACCC, for example, found that:

- those producers that were required to report information, were required to report different information and at different times and levels of geographical aggregation
- there were a number of producers that were not required to publicly report on their reserves and resources (for example, unlisted companies and those listed overseas).

The ACCC also found differences in the bases on which reserves and resources information were calculated by producers.

The need for greater transparency and consistency in reserves and resources reporting has been reinforced through the work the ACCC has carried out on east coast reserves and resources in the current Inquiry. It is for this reason that the ACCC is recommending that the reporting framework specify both:

- the reserves and resources information to be reported by all producers
- the bases on which this information is reported by producers.

When developing its final recommendations on these two aspects of the reporting framework, the ACCC has had regard to the objectives set out in box 1.1 and the feedback provided by stakeholders. The ACCC has also had regard to:

- the Society of Petroleum Engineers' (SPE) Petroleum Resources Management System (PRMS),[13] which is a widely-used principles-based reporting standard for the evaluation and classification of petroleum resources and resources
- the reporting frameworks employed by a number of other Australian and international agencies (see Appendix A), including:
  - the National Offshore Petroleum Titles Administrator (NOPTA)
  - the Queensland Department of Natural Resources, Mines and Energy (DNRME)
  - the Australian Securities Exchange (ASX)
  - the United Kingdom's Oil and Gas Authority (OGA)
  - the Canadian Securities Administrators (CSA)
  - the United States Securities and Exchange Commission (SEC).

The remainder of this section provides an overview of the feedback stakeholders provided on the consultation paper, and the ACCC's final recommendations on these two aspects of the reporting framework.

2.1. Information to be reported

2.1.1. Summary of ACCC's initial proposal and stakeholder feedback

In the consultation paper the ACCC proposed that the following information be reported by producers to AEMO for publication on the Bulletin Board, using the PRMS classification system (see box 2.1):

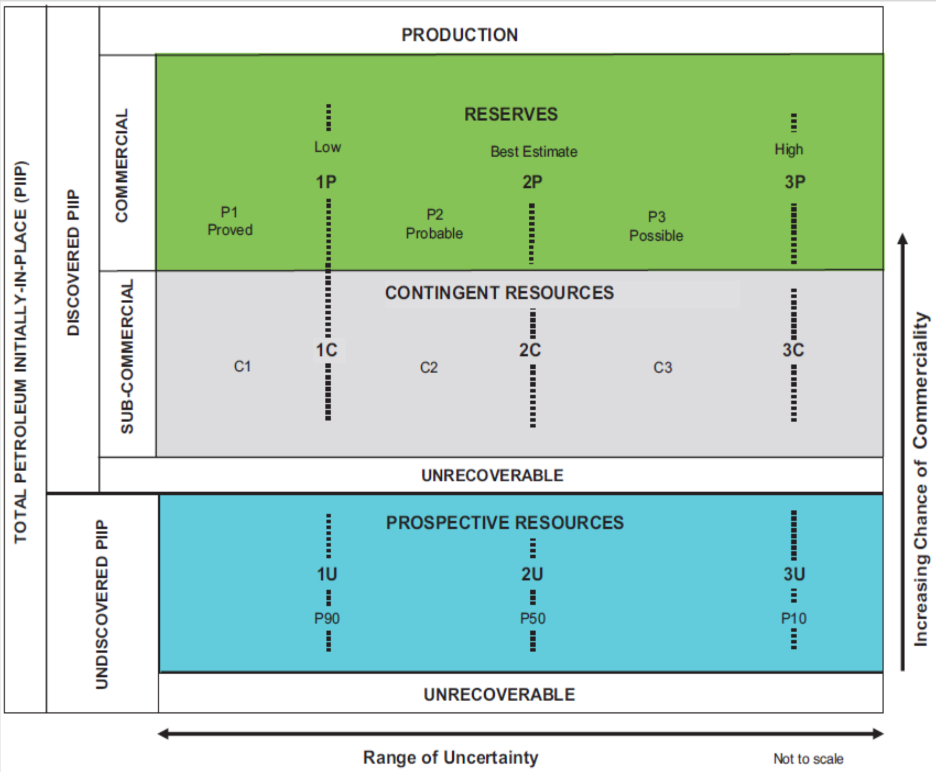
- 1P, 2P and 3P reserves (reported at a field level)

13 SPE, *Petroleum Resources Management System* (PRMS), June 2018.

- 1C and 2C contingent resources (reported at a field level)
- movements in 2P reserves over the last 12 months (reported at a field level)
- information on the type of gas in each gas field, the nature of each gas field (e.g. dry gas field, gas condensate field or oil field) and the development status of each gas field
- the total quantity of reserves contracted under existing GSAs (reported at a basin level).[14]

Box 2.1: PRMS classification system

The PRMS classification system is summarised in the figure below. As this figure shows, when a gas reservoir is discovered, it may be classified as either a reserve or resource (contingent or prospective), depending on its commerciality. Within each category of reserves and resources there are different confidence levels associated with the ability to extract the relevant quantities (for example, reserves may be classified as proved, probable or possible). Reserves may be further classified as developed or undeveloped reserves.



The key terms used in this classification system are defined by PRMS as follows:[15]

- **reserves** are defined as those quantities of gas that the producer has determined to be commercially recoverable and has a firm intention to proceed with development within a reasonable time-frame (e.g. within five years)
- **contingent resources** are defined as those quantities estimated to be potentially recoverable but not yet commercial to develop, due to one or more contingencies (i.e. there is currently no viable market, or commercial recovery depends on the development of technology or infrastructure)
- **prospective resources** are those quantities estimated to be potentially recoverable from undiscovered accumulations by the application of future development projects.

To be categorised a reserve, a project must be sufficiently defined to establish its technical and commercial viability and there must be a reasonable expectation that all required approvals will be forthcoming and evidence of a firm intention to proceed with the development within a reasonable

[14] A different reporting level was proposed for contracted 2P reserves to mitigate the risk that this information reduces competitive rivalry between producers when negotiating with users.

[15] ibid, p. 3.

time frame (PRMS recommends a benchmark of five years be used for this purpose). The term 'reasonable expectation' is defined in PRMS as 'a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur'.

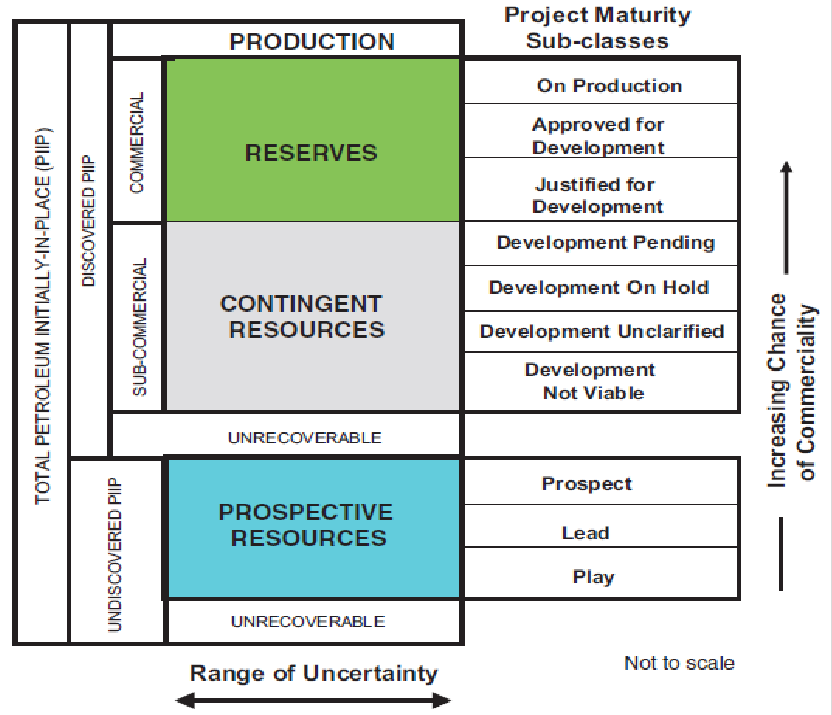
The reserve and resource categories are defined by PRMS as follows:[16]

- **1P** (Proved)**:** low estimate of reserves (if probabilistic methods are used, there should be at least a 90 per cent probability the quantities recovered will equal or exceed the low estimate)
- **2P** (Proved plus probable)**:** best estimate of reserves (if probabilistic methods are used, there should be at least a 50 per cent probability the quantities recovered will equal or exceed this estimate)
- **3P** (Proved plus probable plus possible)**:** high estimate of reserves (if probabilistic methods there should be at least a 10 per cent probability the quantities recovered will equal or exceed this estimate)
- **1C**: low estimate of contingent resources (if probabilistic methods are used, there should be at least a 90 per cent probability the quantities recovered will equal or exceed the low estimate)
- **2C**: best estimate of contingent resources (if probabilistic methods are used, there should be at least a 50 per cent probability the quantities recovered will equal or exceed the best estimate)
- **3C**: high estimate of contingent resources (if probabilistic methods are used, there should be at least a 10 per cent probability the quantities recovered will equal or exceed the best estimate)

Developed reserves and undeveloped reserves are defined by PRMS as follows:[17]

- **developed reserves** are quantities expected to be recovered from existing wells and facilities
- **undeveloped reserves** are quantities expected to be recovered through future significant investments.

The figure below sets out the PRMS project maturity sub-classes.



These sub-classes are defined by PRMS as follows:[18]

- **on production** means the project is currently producing or capable of producing and selling gas

[16] ibid, pp. 13, 35-36.

[17] ibid, p. 34.

[18] ibid, p. 31.

- **approved for development** means all necessary approvals have been obtained, capital funds committed, and implementation of the development project is ready to begin or is under way
- **justified for development** means the project is justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals and contracts will be obtained
- **development pending** means a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future
- **development on hold** means a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay
- **development unclarified** means a discovered accumulation where activities are under evaluation and where justification as a commercial development is unknown based on available information
- **development not viable** means a discovered accumulation for which there are no current plans to develop or to acquire additional data because of limited production potential.

Table 2.1 provides a snapshot of the feedback stakeholders provided in response to these proposals. In this table and the other stakeholder feedback tables contained in sections 2 and 3, green is used to indicate support for the proposal, red to indicate opposition to the proposal and yellow to indicate a position in between these points.

As table 2.1 highlights, most stakeholders supported the proposals to require producers to report on their 1P and 2P reserves, annual movements in 2P reserves and some of the gas field information (i.e. the type of gas contained in the field and the nature of the gas field). Diverse views were, however, expressed on the remainder of the information, with most producers opposed to the mandatory reporting of 3P reserves, 1C and 2C contingent resources and information on a field's stage of development. Retailers, gas users and other stakeholders, on the other hand, generally supported the disclosure of this information.

The other point to note from this table is that a number of producers were opposed to reporting information at a field level (see symbols and notes at the bottom of the table). Their responses are therefore conditional on the information being reported at a basin or other aggregation level. This issue is discussed in further detail in section 2.2.4.

Further detail on the feedback that stakeholders provided and the ACCC's final recommendations on the information to be reported by producers is provided below.

Table 2.1: Stakeholder feedback on the ACCC's proposal on information to be reported by producers

	Reserves information				Resources information				Movements in reserves and resources			Gas field information		
	1P	2P	3P	Reserves broken into developed & undeveloped	1C	2C	3C	Prospective	Movements in 2P Reserves	Movements in 2C Resources	Contracted Reserves	Development status	Type of gas	Nature of field
ACCC proposal														
Producers														
APPEA***			Optional		Optional	Optional							n.a.	n.a.
APLNG***			Optional		Optional	Optional				Optional				
Arrow*			Optional		Optional	Optional								
Cooper Energy**			Optional		Optional	Optional	Optional			Optional		Material projects only		
Esso[+]		Optional	Optional	n.a.	Optional	Optional			n.a.			n.a.	n.a.	n.a.
Origin***					Optional	Optional	Optional	Optional		Optional				
Santos**			Optional		Optional	Optional	Optional	Optional		Optional	Identified issues			
Senex[+]			Optional		Optional	Optional				Optional			n.a.	n.a.
Shell**	Optional		Optional		Optional	Optional					Alternative approach			
Retailers														
AGL*								Optional		Optional				
Energy Australia*						n.a.	n.a.	n.a.		Optional				
Gas users														
Australian Paper*														
Chemistry Australia*														
Other														
Geoscience Australia^	At a minimum 2P should be mandatory to report				At a minimum 2C should be mandatory to report									
Lewis Grey Advisory^														

Notes:
^ Supports reporting at a reservoir level.
* Supports reporting at a field level.
** Supports reporting at a basin level.
*** Supports reporting at another aggregation level (e.g. asset area level).
+ Supports reporting at a basin level or another aggregation level.

2.1.2. Categories of reserves to be reported

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require producers to report 1P, 2P and 3P reserves estimates, along with a breakdown of each reserve category into 'developed' and 'undeveloped' reserves.

As noted above, the majority of stakeholders supported the proposal to require 1P and 2P reserves to be reported and to break these reserves categories down into developed and undeveloped reserves. The notable exceptions to this were:

- Esso, who thought that it should only be mandatory for 1P reserves to be reported, because in its view the uncertainty associated with other reserves categories could "mislead investors/customers".[19]
- Shell, who thought that it should only be mandatory to report 2P reserves, because in its view other reserves categories are of "limited use".[20]
- Chevron, who noted that the requirement to break down reserves into developed and undeveloped reserves would give rise to additional compliance costs.

In contrast to 1P and 2P reserves, there was a clear division in views on whether 3P reserves should be reported. Retailers and gas users, for example, supported the disclosure of this information, while producers thought that, in a similar manner to the ASX listing rules, it should be optional to report this information. A number of producers noted that while they develop a full range of reserves and resources estimates, 3P reserves are more speculative in nature and cannot be relied upon for investment or valuation decisions.[21, 22] Chemistry Australia and Australian Paper, on the other hand, noted that information on 3P reserves would enable better planning and investment decisions over the long-term and therefore advocated the mandatory disclosure of this information.

Final recommendations

The ACCC has considered the feedback provided by stakeholders and while it understands that 2P reserves are generally considered the most realistic assessment of recoverable quantities, uncertainty in reserve estimates is, as noted in PRMS, best communicated by reporting a range of categories.[23] Requiring producers to report 1P reserves will, for example, provide market participants with greater insight into the downside risk associated with the 2P reserve estimates, while 3P reserves will provide a better insight into the potential upside associated with 2P reserves.

While the 3P reserve estimates will, by definition, be subject to greater uncertainty than 1P and 2P reserves, the ACCC would expect most gas market participants to understand this distinction (or could be educated on the distinction through the Bulletin Board reporting). The ACCC does not therefore think this is a sufficient reason to exclude this category from the reporting framework, or to make the reporting of this information optional. The ACCC understands that mandating the reporting of 3P reserves may impose some costs on those producers that are not currently estimating 3P reserves. However, the feedback provided by producers suggests that the majority are already estimating all the reserves and resources categories and, in those cases where they are not, the incremental costs of reporting are not

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19 Esso, Response to Consultation Paper, 12 March 2019, p. 2.

20 Shell, Response to Consultation Paper, 12 March 2019, p. 1.

21 The producers included APLNG, Cooper Energy, Santos, Senex and Shell.

22 In contrast to these producers, Esso noted that it does not routinely estimate 3P reserves.

23 SPE, *PRMS*, June 2018, para 2.2.2.1.

expected to be significant (see producer responses in section 2.2.1). The ACCC recommends therefore that producers be required to report 1P, 2P and 3P reserves to AEMO for publication on the Bulletin Board.

To provide more insight into the risk profiles associated with the reserves and the extent to which further investment may be required to develop the reserves, the ACCC also recommends that producers be required to break their reserve estimates down into the 'developed' and 'undeveloped' reserves, using the definitions set out in PRMS (see box 2.1).

2.1.3. Categories of resources to be reported

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require producers to develop 1C and 2C contingent resource estimates and to report this information to AEMO for publication on the Bulletin Board.

In a similar manner to 3P reserves, producers were of the view that the disclosure of contingent resources should be optional, as it is under the ASX listing rules. While acknowledging that producers usually estimate the full range of contingent resources (i.e. 1C, 2C and 3C),[24] a number of producers noted that contingent resource estimates are highly speculative and could be misinterpreted by market participants, policymakers and investors if they don't have a good understanding of the uncertainties associated with these estimates.[25]

While producers thought the disclosure of this information should be optional, a number of ASX listed producers did note that they are voluntarily reporting on their contingent resources in their annual reports. Santos and Senex, for example, are reporting 2C resource estimates, while Cooper Energy is reporting 1C, 2C and 3C estimates. Like the ASX listing rules, Cooper Energy thought that producers should have the option to report on either their 2C resources, or the full range of contingent resource estimates (i.e. 1C, 2C and 3C resources). Cooper Energy added that reporting the full range of contingent resource estimates would provide a more "balanced view of the resource estimates" than the ACCC's proposal, which was just to require 1C and 2C resources to be reported.[26]

In contrast to the position taken by producers, retailers, gas users and Geoscience Australia thought the disclosure of this information would provide the market with a better understanding of the supply outlook and enable better planning and investment decisions to be made over the longer term. Geoscience Australia noted that 2C contingent resource estimates are typically used as a "yardstick for measuring future supply trends".[27] The ACCC also spoke to an independent industry advisor significantly involved with the PRMS 2018 update, who expressed a similar view and noted the importance of understanding the development status of 2C resources. This independent advisor also suggested that producers classify their contingent resources using the PRMS' project-maturity sub-classes.[28]

In the consultation paper, stakeholders were also asked their view on whether prospective resources should be reported. While most stakeholders thought this was unnecessary, Geoscience Australia noted that while there is less certainty associated with prospective resources, they do provide an indication of the resources that may possibly come online over the longer term, which may be useful for planning purposes.

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24 The exception to this is Esso, who noted that it does not currently develop 1C resource estimates.

25 See for example the responses received from APLNG, Esso, Senex and APPEA.

26 Cooper Energy, Response to Consultation Paper, 12 March 2019, p. 3.

27 Geoscience Australia, Response to Consultation Paper, 15 March 2019, p. 3.

28 These views were provided to the ACCC on an ad-hoc, voluntary basis.

Final recommendations

As a number of stakeholders have pointed out, some care must be taken in relation to contingent resource estimates because, in contrast to reserves, they are not yet considered commercial to develop. Estimates of 2C resources can nevertheless provide valuable insights into the longer-term supply outlook and, as a number of stakeholders noted, are an important input into longer-term consumption, supply, investment and policy decisions.

The importance of 2C estimates to these decisions in the east coast is even more pronounced at present, with AEMO finding in its recent GSOO that contingent resources will be required to meet demand in eastern and south-eastern Australia from 2024.[29] The ACCC therefore recommends that producers be required to report their 2C resource estimates to AEMO for publication on the Bulletin Board.

As noted in section 2.1.5, the ACCC also recommends that producers be required to use the project maturity sub-classes in the PRMS to provide a breakdown of their 2C resource estimates if the field in which they are located satisfies the materiality threshold. The sub-classes include ‘development pending’, ‘development on hold’, ‘development unclarified’ and ‘development not viable’. In the ACCC’s view, the publication of this breakdown will provide market participants and policymakers with more insight into the uncertainty surrounding the 2C resources and the likely development of resources than would be provided by the publication of 1C and 3C resources. The ACCC is not therefore recommending the inclusion of these low and high estimates of contingent resources in the reporting framework.

In relation to prospective resources, the ACCC understands that AEMO currently collects this information from producers for the purposes of the GSOO. In the ACCC’s view, this is the more appropriate forum to report this information, because it is more speculative in nature and requires more contextualisation than can be provided in the Bulletin Board. The ACCC is not therefore recommending that this information be reported on the Bulletin Board. To minimise producers’ reporting costs, the ACCC recommends that:

- AEMO’s collection of information on prospective resources utilise the reporting bases set out in section 2.2[30] and the estimation requirements set out in section 3 [31]
- where relevant and appropriate, AEMO enter into information sharing arrangements with those market bodies and government agencies (e.g. Geoscience Australia) that require access to more detailed prospective resource information.

2.1.4. Movements in reserves and resources

ACCC’s initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require producers to report on the movement in their 2P reserves over the last 12 months to AEMO for publication on the Bulletin Board and to provide a breakdown of the movement arising as a result of:

- the production of gas
- the discovery of new reservoirs in existing fields with 2P reserves
- the extension of a field’s proved area
- acquisitions and divestments of interests in a field

[29] AEMO, Gas Statement of Opportunities, March 2019, p. 39.

[30] For example, the ACCC recommends that quantities of prospective resources be reported in the same manner as contingent resources and that the reserves and that the same evaluation requirements are adopted.

[31] For example, the ACCC recommends that prospective resources be estimated on the basis of forecast conditions and that the gas price assumptions used be based on the same gas prices assumed for uncontracted reserves and contingent resources.

- reserves reassessments (i.e. write-downs or upward revision of 2P reserves)
- other revisions.

As table 2.1 highlights, stakeholders supported the proposal to require annual movements in 2P reserves to be reported. Mixed views were, however, expressed on the categories to be used to report on these movements. APPEA, Arrow, Shell and Australian Paper, for example, agreed with the use of the proposed categories, while other stakeholders suggested a range of changes to these categories. For example:

- APLNG and Origin suggested combining 'reserve reassessments' with 'other revisions'.
- Santos suggested the 'discovery of new reservoirs in existing fields with 2P reserves' category be removed (i.e. because discoveries usually result in changes to contingent resources rather than reserves) and that a new category be introduced to capture non-commercial projects that mature to 2P reserves.
- AGL suggested that producers be required to report on whether a write-down occurs as a result of a technical issue or a change in the commerciality of reserves.
- Chemistry Australia suggested that producers be required to report on any new or changed risk factors that have resulted in a movement in reserves.
- Cooper Energy suggested that 'production' and other 'material changes' be reported, but that immaterial changes be captured in 'other revisions'.

Stakeholders were also asked whether there would be value in requiring producers to report on annual movements in 2C resources. Mixed views were expressed on this issue. Chemistry Australia, Australian Paper and Geoscience Australia, for example, thought it could be beneficial to require this to be reported, while AGL thought that movements should only be reported where there is a material change in 2C resources. Producers were also divided on this issue, with some stating there was little value in requiring this information to be reported,[32] while others thought that, in a similar manner to the ASX listing rules, if a producer elects to report 2C resources, they should also be required to report on annual movements in 2C resources.[33]

Final recommendations

Having regard to the feedback provided by stakeholders, the ACCC recommends that producers be required to report on the movement in their 2P reserves[34] over the last 12 months to AEMO for publication on the Bulletin Board and to provide a breakdown of the movement in reserves arising as a result of:

- the production of gas
- the extension of a field's proved area
- net acquisitions of interests in a field (i.e. acquisitions less divestments)
- a reserves upgrade occurring as a result of either the commercialisation of resources or the reclassification of 3P reserves as 2P reserves
- a reserves downgrade occurring as a result of 2P reserves being re-classified as either 3P reserves or contingent resources
- other revisions.

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[32] See for example, the responses provided by APPEA, APLNG, Arrow Energy, Esso, Senex and Shell.

[33] See for example, the responses provided by Cooper Energy and Santos.

[34] As set out in section 2.2.4, these movements should be reported at a gas field level.

In keeping with a number of suggestions from stakeholders, this list of categories has been amended to:

- remove the requirement to report on movements arising from discoveries
- allow acquisitions and divestments to be reported on a net basis
- require producers to separately report on reserves upgrades and downgrades.

The amended list of categories is intended to provide market participants and policymakers greater insight into the drivers of any changes in 2P reserves and the supply outlook from year-to-year. It will, for example, provide an indication of:

- the extent to which production from a field is being replaced (e.g. through extensions or reserves upgrades) and if further investment may be required
- whether a field is in decline or if there is still some upside potential
- the performance of a field and development risks, particularly if there has been a reserves downgrade.[35]

In contrast to the movement in 2P reserves, the ACCC is not convinced of the need to require producers to report on movements in 2C resources, given that changes to 2C resources arising as a result of reserves upgrades and downgrades will already be reported. The only potential limitation with not reporting on movements in 2C resources is that market participants will not be able to distinguish between changes in 2C resources arising as a result of new discoveries and net acquisitions. This does not, however, appear to be a significant enough issue to warrant imposing additional reporting costs on producers. The ACCC is not therefore recommending the inclusion of this information in the reporting framework.

2.1.5. Gas field information

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback from stakeholders on the proposal to require the following information to be reported for each field in which reserves and resources are located:

- the field's development status
- the type of resource in the field (e.g. conventional natural gas, coal seam gas, or another type of unconventional gas)
- the nature of the field (e.g. a dry gas field, a gas condensate field, or an oil field).

The proposal to require producers to report this information was supported by AGL, EnergyAustralia, Australian Paper, Chemistry Australia, Geoscience Australia and Lewis Grey Advisory. The importance of this information and, in particular, the stage of development information was also highlighted by Geoscience Australia, who noted that "understanding when supply may be available to the market is as important as understanding how much oil and/or gas may be available".[36]

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[35] The insights that can be provided by this type of information were highlighted in section 2.7 of the Gas Inquiry December 2018 Interim Report. In short, the analysis in this section, which was based on equivalent information to that described above, showed that 2P reserves had fallen by approximately 5000 PJ (~12 per cent) in the 12 months to 30 June 2018, with the majority of the decline arising as a result of significant write downs in the Bowen and Surat basins. It also showed that while 2P reserves had declined in most basins over the period, they had actually grown in the Otway basin as a result of extensions.

See ACCC, *Gas Inquiry 2017-2020 Interim Report,* December 2018, pp. 51-52.

[36] Geoscience Australia, Response to Consultation Paper, 15 March 2019, p. 3.

In contrast to this position, APPEA, APLNG, Origin[37] and Senex claimed there would be little benefit in requiring producers to disclose information on a field's development status and noted that it would increase the reporting burden. While Cooper Energy was also opposed to reporting on each field's stage of development, it noted that an alternative solution may be to limit the requirement to report this information to projects that could have a material impact on the gas market. Arrow and Shell, on the other hand, were not averse to reporting this information, but Shell noted that the information should be reported at a basin level rather than at a field level.

In addition to this feedback, stakeholders identified a number of potential improvements to this element of the reporting framework. For instance:

- Geoscience Australia suggested that:
  - the reporting framework include a standard list of 'development stages' that will provide more insight into when production is likely to commence
  - the reporting framework recognise other types of unconventional gas, such as shale gas, tight gas, basin centred gas, deep coal gas and syngas
  - producers be required to report more information on the location and size of the field (e.g. the state, the latitude and longitude of the field, the area covered by the field (in square kilometres) and the permit number
- Cooper Energy suggested that material projects that are approved for development but not yet 'on production', be required to report an estimated date(s) for the start of production. In a similar manner, Lewis Grey Advisory suggested that more detail be reported on the timing of developments expected to occur in the next five years
- Chemistry Australia suggested that producers be required to report on risk factors (e.g. contaminants, reserve or resource depth and geology) that may affect the commercial or technical viability of a development or the timing of a development
- EnergyAustralia suggested that forecasts of expected production from each field be reported on an annual basis at an aggregated level.

Final recommendations

As the preceding discussion highlights, information on a field's development status was the most contentious element of the gas field information. While some producers have sought to downplay the importance of this information, it is, as a number of stakeholders pointed out, required to understand the likelihood that projects within a field will be developed and the likely timing of those developments. The importance of this information cannot be understated in the current environment and is critical to ensuring that gas users, producers and infrastructure operators can respond to the economically efficient investment signals provided by this information. The ACCC therefore recommends that producers be required to report on the development status of their 2P reserves and 2C resources.

To minimise the reporting costs associated with this reporting requirement, the ACCC recommends that a materiality threshold of 50 PJ be adopted. Specifically, the ACCC recommends that producers only be required to report on the development status of those fields with at least 50 PJ of reserves or contingent resources. The information that the ACCC recommends be reported in this context, which reflects the feedback provided by a number of stakeholders, includes the following:

- 2P reserves:

[37] While APLNG and Origin did not think there was any value in disclosing information on the stage of development, they did think that information on the type of gas and the nature of the gas field could be reported.

- a breakdown of 2P reserves[38] using the PRMS project maturity sub-classes (i.e. 'on production', 'approved for development' and 'justified for development')
- an estimate of when production is likely to commence for those 2P reserves classified as 'approved for development' or 'justified for development'[39]

- 2C resources:
  - a breakdown of 2C resources using the PRMS project maturity sub-classes (i.e. 'development pending', 'development on hold', 'development unclassified' and 'development not viable')
  - an estimate of when production from the 2C resources classified as 'development pending' and 'development on hold' could commence if these resources are commercialised and a decision is made to proceed with their development
  - a list of any barriers to the commercial recovery of 2C resources in that field (e.g. pipeline development, successful appraisal, environmental approval or technology under development).

In addition to this information, the ACCC recommends that producers be required to report the following information to AEMO for publication on the Bulletin Board for each of the fields in which their reserves and resources are located:

- the type of gas contained in the field and, in particular, whether the field is a conventional natural gas, coal seam gas, or another type of unconventional gas[40]
- the nature of the field and, in particular, whether the field is a dry gas field (mostly methane), a gas condensate field (mainly condensates or liquid hydrocarbons), or an oil field (where gas is found associated with oil)
- the location of the field, the permit[41] number associated with the field and the percentage interest that the producer has in the field (measured on a net-revenue basis).

Together with the information on the development status of fields that meet the materiality threshold, this information will provide more of an insight into:

- the likelihood of 2P reserves and 2C resources being developed, the timing of any such development and the risks associated with those developments in fields that satisfy the materiality threshold
- a number of factors that can affect the performance of a field and the development and production costs and risks that may be faced by a producer in a particular field.

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38 To minimise reporting costs for producers, this recommendation has been limited to 2P reserves.

39 As noted in box 2.1, PRMS recommends a benchmark of five years be used for the initiation of development, although it notes that a longer timeframe could be applied where justifiable.
SPE, PRMS, June 2018, p. 7.

40 As Geoscience Australia noted there may be value in requiring the 'other unconventional' category to be further broken down into shale gas, tight gas, basin centred gas, deep coal gas and syngas.

41 The term 'permit' is used in this context to refer to any type of resource authority (e.g. exploration permits, retention leases, production licences, authorities to prospect and petroleum leases).

As to EnergyAustralia's suggestion that producers also be required to report on expected production from each field, the ACCC understands that AEMO currently collects this information for the GSOO for a 20 year outlook period. In the ACCC's view, this is a more appropriate forum to report this type of information. The ACCC does, however, think there would be value in AEMO publishing more detail on the expected gas production profile in each basin (or on a more aggregated basis if there are less than three producers operating in a basin) to provide market participants and policymakers with more of an insight into the production outlook for each basin.[42]

2.1.6. Contracted reserves

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback from stakeholders on the proposal to require:

(a) producers to report on the total quantity of gas that they are contracted to supply under their GSAs at a basin level to AEMO for publication on the Bulletin Board

(b) AEMO to determine whether there are at least three producers operating in the basin before publishing the information on the Bulletin Board and, if not, to further aggregate the data (e.g. by region) to ensure this threshold is met.[43]

The latter of these proposals was designed to mitigate the risk that the publication of individual producers' positions could accord those producers that have uncontracted reserves a greater degree of bargaining power in negotiations with gas users.[44]

As table 2.1 highlights, most producers were opposed to the disclosure of this information. The notable exceptions to this were Santos and Arrow, although both of these producers identified some specific concerns with the proposal. The main concern producers had with this disclosure was that it could mislead market participants if it was interpreted as a measure of the current availability of gas. Elaborating on this further, Santos noted that:[45]

> *"Listing contracted and uncontracted reserves may be misinterpreted by some market participants as current availability of gas. Actual production profiles will be extend [sic] well beyond the period when existing contracts expire. Thus when calculating uncontracted reserves, it will not be possible to determine the level each year as a large portion of the uncontracted reserves are far outside our contracting window, limiting the usefulness of this information."*

Concerns were also raised about the potential for this information to mislead the market, if it resulted in an expectation that producers could sell up to 100 per cent of their reserves. In this regard, a number of producers noted that they need to maintain a "buffer of uncontracted production" to account for the uncertainty in reserves development and maintenance.[46] Cooper Energy and Senex also expressed some concern about the potential for the disclosure of this information to adversely affect a producer's commercial position, while

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[42] The publication of this information would be consistent with the information published by the New Zealand Ministry of Business, Innovation & Employment on the production profiles for each basin. See the Reserves.xlsx spreadsheet on https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/.

[43] If the information is aggregated across at least three producers, it will be impossible for one party to work out the actual quantity of the contracted reserves of another party without access to the private market information of one of the other parties.

[44] ACCC and GMRG, *Joint recommendations: Measures to improve the transparency of the gas market*, December 2018, p. 16.

[45] Santos, Response to Consultation Paper, 14 March 2019, p. 4.

[46] See for example, the responses received from APLNG, Origin and APPEA.

APPEA claimed that this disclosure would “significantly increase the reporting and compliance/reporting burden”.[47]

In addition to these concerns, a number of stakeholders noted that if this information is to be reported, then consideration would need to be given to:

- how to measure the volume of gas contracted and, in particular, how to account for:
  - purchases of gas by producers to satisfy their contractual commitments (i.e. to ensure there is no double counting of contracted reserves)
  - the volume flexibility contained within GSAs, which may result in some degree of variation in the volume of gas to be supplied under a contract
  - spot sales and short-term GSAs
- how to aggregate the information in a manner that:
  - does not adversely affect a producer’s commercial or competitive position[48]
  - recognises that some producers contract on a whole of portfolio basis and so are unable to attribute contracted reserves to a particular basin.

Rather than requiring producers to disclose their contracted reserves on the Bulletin Board, Shell suggested that an aggregate demand-supply forecast be published that reflects producers’ forecast production and contractual commitments be published. Shell noted that this type of forecast would be more useful to market participants than information on contracted reserves.

In contrast to producers, Geoscience Australia, AGL, EnergyAustralia, Australian Paper and Chemistry Australia supported the disclosure of information on contracted reserves. In doing so, Geoscience Australia noted that the disclosure of this information would improve the transparency surrounding potential supply shortfalls. Lewis Grey Advisory also supported the disclosure of this information, but suggested that:

- contracted volumes be reported for each year (e.g. contracted volumes in 2018, 2019 and 2020), rather than on an aggregate basis
- separate volumes be reported for contracts involving the supply of gas to the domestic market and contracts involving the supply of gas to export markets.

Final recommendations

The ACCC understands from the feedback provided by stakeholders that there are some limitations with the approach to the reporting of contracted reserves that was proposed in the consultation paper. The main limitation is that, on its own, it provides no indication of when any uncontracted reserves may be available (e.g. next year, in five years or in 20 years). This proposal is unlikely therefore, in its current form, to achieve the stated objective of providing gas users and other market participants and policymakers with an indication of the availability of uncontracted gas.

As some stakeholders pointed out, one way that this limitation could be overcome is to require producers to report on the volume of gas that they have contracted to sell in each

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47 APPEA, Response to Consultation Paper, 12 March 2019, p. 3.

48 Esso, for example, noted that in basins such as the Gippsland Basin where there are currently only four producers, basin level disclosure may be ‘competitively damaging’ because market participants may be able to infer the contracted reserves of individual suppliers. Esso therefore suggested that aggregation in Victoria occur at an offshore Victoria level.

Arrow also noted that even if there are three or more producers operating in a basin, consideration should be given to the total volume of gas contracted to each producer before deciding to aggregate on this basis.

AGL thought that there should be at least five producers to ensure that market participants could not infer the contracted volumes of each supplier.

year over the life of their GSAs. However, unless this is accompanied by information on how much gas is expected to be produced in each year, it will not provide any insight into the volume of uncontracted gas available in each year. While it would be possible to require producers to report this information and to then calculate the volume of uncontracted gas in each year, AEMO would still need to carry out further work to:

(a) ensure that there is no double counting of gas sales, which could occur if producers have to purchase gas from others to satisfy their contractual commitments

(b) account for the effect of any volume flexibility that may be provided for under the GSAs[49]

(c) aggregate the information to mitigate the risk that producers with uncontracted volumes will have a greater degree of bargaining power in negotiations with users. [50, 51]

Given the nature of the work that would be required and the time it is likely to take, the ACCC recommends that this information be collected and reported on by AEMO on an annual basis through the GSOO, rather than through the Bulletin Board. In the ACCC's view, the GSOO is a better forum for the publication of this information, because it will enable AEMO to properly vet the data and to report on the availability of uncontracted gas in a way that is of most use to market participants and policymakers, whilst also recognising the competition concerns outlined in (c). To give effect to this recommendation, the National Gas Rules will need to be amended to enable AEMO to obtain this information from producers.

AEMO could, for example, report on the availability of uncontracted gas in Queensland and the Southern States in each year over the 20-year GSOO forecast period. Reporting the information in this manner would be more consistent with what the ACCC and GMRG envisaged when they recommended the publication of information on contracted reserves and would ensure that the stated objective of this transparency measure is met. The ACCC is therefore no longer proposing that this information form part of the reporting framework.

2.2. Bases on which information is reported

2.2.1. Summary of ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC suggested that reserves and resources information be reported on the following bases:

- **Reporting standard**: Classification of reserves and resources and the definition of key terms to be based on the PRMS.
- **Quantities to be reported and estimation methods**: Reserves and resources to be measured on the basis of the producer's net revenue interest in the sales quantities of gas (measured in PJ) from all gas containing fields and estimation methods to be disclosed. Box 2.2 provides further detail on these quantity and estimation method concepts, which are drawn from the PRMS.
- **Reporting level**: Reserves and resources information (including the movement in 2P reserves) to be reported at a field level.

[49] While the use of annual contract quantities should be sufficient, it may be worth testing the effect of using the take or pay volumes (i.e. the minimum amount the gas user has to pay for in the year) or the mid-point between the take or pay and the annual contract quantities. In relation to other forms of volume flexibility, such as an option to increase or decrease contract volumes, the ACCC would suggest that this only be accounted for when the option is exercised.

[50] As noted in the joint ACCC-GMRG recommendations, when the supply-demand balance is tight, as it currently is in the east coast, there is a risk that the publication of individual producers' positions could accord those producers that have uncontracted reserves a greater degree of bargaining power in negotiations with gas user.

ACCC and GMRG, *Joint recommendations: Measures to improve the transparency of the gas market*, December 2018, p. 16.

[51] If the information is aggregated across at least three producers that are operating independently (e.g. they are not related parties and are not operating together in a joint venture), it will not be possible for one party to work out the actual quantity of the contracted reserves of another party without access to the private market information of the other party.

- **Reporting timing and frequency**: Reserves and resources estimates to be reported annually, but if an intra-year assessment is carried out by a producer and this results in a material change in reserves or resources, the updated information should be reported as soon as practicable.
- **Evaluation requirements**: Reserves and resources estimates to be prepared by, or under the supervision of, a qualified independent evaluator.

Box 2.2: Relevant PRMS concepts

Quantity concepts

The proposed reporting framework drew on the following quantity concepts:

- **net revenue interest,** which is a producer's revenue share of sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms[52]
- **sales quantities,** which are the quantities available for sale after excluding the gas consumed, flared or lost in operations and non-hydrocarbons that must be removed before sale.[53]

Estimation methods

The PRMS recognises a range of resources assessment methods, including:[54]

- the **deterministic** assessment method, which is based on discrete estimate(s) corresponding to a given level of certainty, made based on available geoscience, engineering, and economic data
- the **probabilistic** assessment method, which uses known geoscience, engineering, and economic data to generate a continuous range of estimates and their associated probabilities
- **geostatistical** assessment methods, which include a variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool
- **integrated** methods such as the multi-scenario method, which is an extension of the deterministic scenario method and involves the development of a significant number of discrete deterministic scenarios and may also involve probabilities being assigned to each input assumption, from which the probability of the scenario can be determined.

Table 2.2 provides a snapshot of the feedback that stakeholders provided in response to each of these proposals. As this table shows, stakeholders were broadly supportive of annual reporting and the proposed reporting standard. Differences in views were, however, expressed by producers and other stakeholders on the proposed:

- reporting level
- timing of reporting
- involvement of an independent evaluator in the reserves and resources assessment.

In each of these cases, producers cited compliance costs as a key concern. In contrast, gas users, retailers and other stakeholders tended to focus on the quality and usefulness of the information that would be reported using these reporting bases.

The focus of producers on compliance costs was also reflected in their responses to the following questions that were set out in the consultation paper:

- set out the incremental costs that producers are likely to incur complying with the proposed reporting requirements

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52 SPE, *PRMS*, June 2018, pp 45, 23-24.

53 ibid, p. 20.

54 ibid, pp. 40, 43, 46.

- identify any refinements that could be made to the reporting framework to minimise the proposed compliance costs.

Table 2.3 provides a summary of the feedback stakeholders provided on these questions.

Table 2.2: Stakeholder feedback on the ACCC's proposal on the bases on which information is to be reported

	Classification system	Reporting level	Quantities		Timing			Evaluation
	PRMS	Field level	Net revenue interest in sales quantities	Disclose analytical method	Annual	At fixed date	Report material changes	By, or under supervision of, independent evaluator
ACCC proposal								
Producers								
APPEA		***	ô				Limited to other public reporting	
APLNG		**					Limited to other public reporting	
Arrow						Supportive if it aligns with other reporting	Limited to other public reporting	
Cooper Energy		**	Working interest				Limited to other public reporting	
Esso	n.a	*		Optional				
Origin		***					Limited to other public reporting	
Santos		**		Alternative approach			Limited to other public reporting	
Senex		*	ô				Limited to other public reporting	
Shell	#	**						
Retailers								
AGL					Alternative approach			
Energy Australia	n.a							
Gas users								
Australian Paper								
Chemistry Australia	n.a							
Other								
Geoscience Australia		^	ô					Alternative approach
Lewis Grey Advisory		^		Alternative approach				n.a

Notes:
Suggested there should be flexibility to report 1P reserves under the SEC framework
ô Supports the option to report quantities on a gross basis and separately disclose gas consumed in operations.
^ Supports reporting at a reservoir level.
* Supports reporting at a field level.
** Supports reporting at a basin level.
*** Supports reporting at another aggregation level (e.g. asset area level).
+ Supports reporting at a basin level or another aggregation level.

Table 2.3: Stakeholder feedback on costs of complying with the proposed reporting requirements

	Incremental costs	Other feedback
Producers		
APLNG	*"APLNG estimates that it will take several* [person]-*months of its independent qualified evaluators to quantify the alternate reserve detail*."	*"APLNG's biggest concern would be the added confusion caused by having multiple reserve reports and the need to constantly reconcile the differences*." "*Having reporting guidelines that are different than the DNRME will cause additional costs to producers having to explain the differences*."
Arrow	Noted that it is difficult to measure the incremental costs at this stage	Suggested costs could be reduced if information could, in the case of joint ventures, be reported by the operator rather than by each producer.
Cooper Energy	Noted that there would be no material incremental costs with the information to be reported, but the bases on which information is reported will require additional time, cost and resources.	n.a.
Esso	*"...many of the proposed disclosures require a degree of granularity not currently present in our reporting and consolidation processes. This will necessitate costly changes to these systems*." Noted that an independent evaluation requirement "*would be overly onerous and cost prohibitive (indicatively A$2M for first evaluation and A$1M per year thereafter)*"	Suggested that costs could be reduced by limiting reporting to 1P, allowing each producer to determine its annual reporting date, no requirement for independent evaluation and reporting at a basin level rather than a field level.
Origin	*"…preliminary view is that at least two FTEs, operating over a period of two months, would be required to assist with disaggregating reserves/resources information at a field level alone. We estimate that staffing requirements would likely increase by around two weeks for every additional change that represents a significant deviation from existing reporting practices."*	Suggested that maintaining consistency with the ASX framework would reduce compliance costs and the regulatory burden.
Santos	*"No material incremental cost if reporting at a basin level."*	Suggested that reporting costs could be minimised if reserves and resources information was reported at basin level.
Senex	*"Additional time for independent auditors, and additional time and resources generally, will be required to comply with this requirements. The quantum will depend on size of portfolio and number of fields but we expect the additional expense will be significant.'"*	n.a.
Shell	*"Shell estimates the additional compliance costs to be [c-i-c]… based on additional internal resources to generate volume estimates not currently required and for engaging independent reserves evaluators."*	Suggested costs could be reduced via alignment with other reporting agencies, flexibility to report SEC proved reserves instead of PRMS 1P, optional reporting, no intra-year reporting, no requirement for independent evaluation.
Other Stakeholders		
AGL	*"If an independent certification is required that would amount to a cost of approximately [c.i.c] per field. Costs for recalculation at the reporting date would amount to less than [c.i.c] for associated internal costs."*	Suggested costs could be reduced by limiting the requirement for an independent report and alignment with ASX reporting requirements.
Chemistry Australia	*"Given this information is already developed for producers own use, and this reform exercise is about eliminating information asymmetry, the cost of disclosing and providing it to regulators is likely to be minimal."*	n.a.

As table 2.3 shows, most of the concerns expressed by producers related to the bases on which information is to be reported, rather than the information to be reported. The costs that producers were particularly concerned about were those associated with having to:

- report information at a field level
- report information at a different time to producers' other reporting obligations
- report on material changes in reserves and resources that occur within the year
- retain an independent evaluator.

Further detail on the feedback provided by stakeholders in relation to the bases on which information is to be reported by producers is set out below, along with the ACCC's final recommendations.

2.2.2. Reporting standard

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require producers to use the PRMS classification system and other PRMS concepts when reporting their reserves and resources and the other information set out in section 2.1.

All the stakeholders that responded to this aspect of the reporting framework supported the use of PRMS, however:

- Shell qualified its support for the use of PRMS by suggesting that producers have the flexibility to report 1P reserves using the US SEC's reporting framework[55]
- Esso, which is a US-listed company, noted its preference for any reporting to be on a consistent basis with US SEC's reporting framework.[56]

Final recommendations

Having considered the feedback provided by stakeholders, the ACCC recommends that producers be required to:

- use the PRMS classification system when reporting the reserves and resources information set out in section 2.1
- use the PRMS definitions set out in box 2.1 when reporting:
  - the breakdown of 1P, 2P and 3P reserves into developed and undeveloped reserves
  - the project maturity sub-classes for 2P reserves and 2C resources in fields that satisfy the materiality threshold
  - the quantities of reserves and resources
  - the analytical method used to estimate reserves and resources.

The ACCC also recommends that any changes to these aspects of the PRMS over time automatically flow through to the reporting framework.

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[55] Shell, Response to Consultation Paper, 12 March 2019, p. 10.

[56] Esso, Response to Consultation Paper, 12 March 2019, pp. 1, 5.

The use of the PRMS in this manner is expected to minimise producers' reporting and compliance costs because it is also used by the ASX and a number of other Australian agencies, including NOPTA and the DNRME. [57]

In relation to Shell and Esso's suggestion that US-listed entities be allowed to use the SEC's reporting framework when reporting their 1P reserves, the ACCC notes that the use of this alternative framework is unlikely to reduce their reporting costs because 2P and 3P estimates, of which 1P estimates form a part, will still need to be estimated using the PRMS. The use of this alternative framework could also result in inconsistencies in reporting across producers and inconsistencies with other aspects of the reporting framework.[58] This would undermine the ACCC's objective of achieving consistent reporting to better facilitate economically efficient investment signalling.[59] The ACCC does not therefore support the use of this alternative reporting framework by US-listed entities.

2.2.3. Quantities and estimation methods

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposals that:

- the reserve and resource quantities outlined in section 2.1 be based on the producer's net revenue interest in the sales quantities of gas (measured in PJ)
- producers determine which analytical method to use when estimating the quantities (see box 2.1 for more detail on these methods) and disclose the method used.

The proposal that quantities be reported on a sales quantity basis was supported by APLNG, Arrow, Origin, Santos, AGL, EnergyAustralia, Australian Paper, Chemistry Australia and Lewis Grey Advisory. APPEA, Senex and Geoscience Australia qualified their support for the proposal by suggesting that producers should have the option to report quantities on a gross basis and separately disclose non-sales quantities. In contrast to these stakeholders, Shell was of the view that quantities should only be reported on a gross basis (consistent with the approach used by the DNRME), while Esso was of the view that a dry gas basis should be used (consistent with SEC requirements).

The proposal that quantities be reported on a net revenue interest basis was generally supported by those stakeholders that supported reporting on a sales quantity basis. However, a number of stakeholders raised issues relating to joint ventures:

- AGL and Geoscience Australia supported reporting on a net revenue interest basis provided a breakdown of joint venture ownership is also reported
- Esso did not support reporting on a net revenue interest basis, stating that joint venture partners use different bases (assumptions) for future net revenue calculations
- Lewis Grey Advisory noted that if a net revenue interest basis was used then each joint venture partner would have to report separately.

Cooper Energy did not support reporting on a net revenue interest basis, instead suggesting that a working interest basis be used. Cooper stated that using a working interest basis removes specific license or jurisdictional fiscal terms and differences in cost structures from the estimation of net volumes.

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57 The ACCC notes that the PRMS classification system is used by NOPTA, the ASX and DNRME to classify reserves and resources. The definitions outlined in box 2.1 are also used by the ASX

58 For example, the SEC requires 1P reserves to be estimated using historic prices, while the ACCC is recommending that forecast prices be used.

59 As set out in box 1.1.

The proposal that producers disclose the analytical method used was supported by APLNG, Arrow, Origin, Senex, AGL, EnergyAustralia, Australian Paper, Chemistry Australia and Geoscience Australia. APPEA noted that this is already disclosed by those producers subject to ASX reporting requirements. Esso stated that the disclosure should be optional because each method achieves the appropriate level of certainty. Esso's suggestion was echoed by:

- Shell, who stated that a particular method does not inherently imply greater or lesser confidence
- Cooper Energy, who did not support disclosure of the analytical method, stating that PRMS allows a choice of methods and the one chosen is 'somewhat irrelevant' to the confidence level
- Lewis Grey Advisory, who suggested that producers be required to certify that the method meets the reporting requirements
- Santos, who stated that a combination of analytical methods is often used, and suggested that a general comment on the analytical method should instead be provided.

In contrast, Geoscience Australia stated that the estimation method used materially reflects the limitations associated with the provided estimate, while Chemistry Australia stated that the analytical method is a 'critical factor'.

Geoscience Australia also noted in its submission that volumes should be reported in trillions of cubic feet (Tcf) rather than in petajoules, or if the information is to be reported in petajoules then producers should either be required to use a specified conversion factor or to disclose the conversion factor that they have used.

Final recommendations

The ACCC has considered the feedback provided on how quantities should be reported and while it understands that it may be easier for some producers to report on a gross basis, it is concerned that the adoption of this approach could mislead market participants and policymakers (i.e. by overstating the volume of gas that could be supplied to the market). The adoption of this approach would also be inconsistent with the PRMS,[60] which recommends that reserves be measured on a sales quantity basis. [61]

As to the concerns raised by some stakeholders about the requirement for each producer to report their reserves and resources on a net revenue interest basis, the ACCC understands that this approach will give rise to higher reporting costs than would be the case if a field operator could report on behalf of a joint venture. The ACCC is, however, concerned that if a field operator is required to report on behalf of a joint venture, it may result in joint venture parties that are separately marketing their gas sharing information on the prices they currently receive for gas and their expectations for the future. This could, in turn, facilitate coordinated conduct between producers, which would have a deleterious effect on competition and on gas users.

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60 This approach is also employed by the ASX. See ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.25.5.

61 SPE, *PRMS*, June 2018, p. 3.

Given the concerns outlined above, the ACCC recommends that producers be required to report the reserves and resources information set out in section 2.1 on:

- a sales quantity basis, which represents the gas available for sale after excluding the gas consumed, flared or lost in operations and non-hydrocarbons that must be removed before sale[62, 63]
- a net revenue interest basis, which represents the producer's revenue share of gas sales after deducting royalties or the share of production owing to others under applicable lease and fiscal terms.[64]

To ensure consistency in the way these quantities are reported, the ACCC recommends that this information be reported in petajoules (PJ) and that producers be required to disclose the conversion factor they have used when converting their reserves and resources estimates into petajoules.

In a similar manner to the PRMS, the ACCC is of the view that producers should have some discretion as to the method(s) used to estimate their reserves and resources (see box 2.2 for more detail on these methods). The ACCC does, however, recommend that producers be required to disclose the method(s) they have used when reporting these quantities.[65]

2.2.4. Reporting level

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on its proposal to require information on producers' reserves and resources (including movements in 2P reserves) to be reported at a field level. Mixed views were expressed on the proposal, with some stakeholders supporting the proposal,[66] while others suggested reserves and resources be reported at:

- **A more granular level**: Lewis Grey Advisory and Geoscience Australia, for example, suggested that this information be reported at a reservoir level. In doing so, they noted that producers generally calculate reserves and resources estimates at a reservoir level and then aggregate these to produce a field level estimate, so reporting at this level should not be too 'onerous'. Geoscience Australia also noted that collecting information at a reservoir level would enable more detailed estimates of reserve and resource related parameter (e.g. reserve life) to be developed.
- **A more aggregated level**: Cooper Energy, Santos and Shell, for example, suggested that this information be reported at a basin level, Esso suggested it be reported at a basin or more aggregated level, and APLNG and Origin suggested it be reported at an asset area level. One of the main concerns that producers raised about having to report at a field or reservoir level is that would give rise to higher reporting costs. The following concerns were also raised about having to report at a field or reservoir level:
  - Esso noted that a wider range of variance in reserves and resources estimates could be expected if more granular information is reported, which it claimed could mislead market participants. Senex made a similar observation, noting that the "accuracy of estimates at a field level can be significantly less than when reserves are aggregated into reporting categories that are appropriate to the producer's circumstances".[67]

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62 ibid.

63 The ACCC understands this differs from the approach adopted by the DNRME, which is that reserves be reported in each underground reservoir and therefore includes gas consumed, flared or lost in operations (see *Queensland Petroleum and Gas (General Provisions) Regulation* 2017, r. 43). It is, however, consistent with the approach recommended by PRMS and the approach required by the ASX (see ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.39).

64 SPE, *PRMS*, June 2018, p. 45.

65 This is consistent with the approach employed by the ASX. See ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.25.6.

66 See for example, the responses received from AGL, EnergyAustralia, Chemistry Australia, Australian Paper and Arrow.

67 Senex, Response to Consultation Paper, 12 March 2019, p. 5.

- Esso claimed that the publication of field level data could have a range of adverse effects on producers, including limiting an individual producer's competitive advantage and reducing the opportunity for sales or other negotiations by "establishing a publicly posted value as an anchor point".[68] Chevron expressed similar concerns, noting that the disclosure of field level information may "unintentionally lead to the disclosure of commercially sensitive, proprietary information developed as part of our competitive advantage, thereby distorting competition in the industry".[69]

Final recommendations

The ACCC has considered the feedback provided by stakeholders and while it understands the desire of those stakeholders with a technical focus to have access to reservoir level data, the objectives of the reporting framework are to:

- provide market participants and policymakers with a better understanding of the supply outlook to enable more informed and efficient decisions to be made
- signal any changes to the supply outlook in timely and effective manner to enable the market to respond more efficiently to changing conditions.

One concern the ACCC has with reservoir level reporting is that it would result in a significant amount of information being reported, which would increase the reporting costs. It is also not clear that reporting at a reservoir level would provide market participants or policymakers any better insights into the supply outlook or potential supply issues than could be obtained from field level data. Conversely, if the reserves and resources information was reported at a basin or area of interest level as proposed by a number of producers, then it could limit the usefulness of the information and the effectiveness of the signals emerging from this information, because reporting at this aggregated level could mask a number of issues.[70]

While some producers have claimed that their reporting costs would be lower if they were to report at a more aggregated level, this claim appears overstated given that producers would still need to estimate their reserves at a reservoir or tenement level before aggregating it up to a basin level.[71] The claim that field level reporting could mislead market participants and/or have an adverse effect on competition also appears overstated, given that the DNRME has been publishing information on Queensland producers' reserves at a reservoir level for a number of years and there is no evidence it has had these effects.

Having considered both angles, the ACCC is of the view that field level reporting would be more consistent with the objectives set out in box 1.1 than the more granular and aggregated alternatives. It will, for example, provide more insight into the differences in the performance and risks associated with each field in which a producer has an interest. It will also provide an indication of how close the reserves and resources are to existing infrastructure and further insight into some of the development risks that may be associated with those reserves and resources.

The ACCC understands that the position it has reached on this issue is the same as that reached by the Australian Energy Market Commission (AEMC) in its East Coast Wholesale Gas Markets and Pipeline Frameworks Review.[72] In that review, the AEMC noted that

68 Esso, Response to Consultation Paper, 12 March 2019, p. 6.

69 Chevron, Response to Consultation Paper, 14 March 2019, p. 2.

70 For example, if a producer had a number of fields in a basin and there was a reserves downgrade in one field that had been expected to commence production in the next 1-2 years and an offsetting upgrade in another field that was not expected to commence production for 5-6 years, then the effect on the supply outlook may not be immediately obvious, because there would be no net change in reserve levels.

71 It is also worth noting in this context that the ACCC has previously been provided with field level reserves and resources information by producers and no concerns were raised in this context about the costs or complexities with doing so.

72 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review - Stage 2 Final Report Information Provision,* 23 May 2016, pp. 64-65.

reporting at a field level would be less onerous than that applied by the DNRME in Queensland where reserves are reported on a reservoir basis.[73] The ACCC agrees with the AEMC and notes that this approach would also be less onerous than that employed by NOPTA, which requires reserves and resources to be reported for each pool within a field.

2.2.5. Frequency and timing of reporting

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require producers to report the information set out in section 2.1 on an annual basis and to also report on any material intra-year changes in reserves and resources. The ACCC also sought stakeholder views on whether:

- the timing of annual reporting should be:
  - (a) at a fixed date, which is the approach employed by the DNRME[74]
  - (b) at the end of the producer's financial year, which is the approach employed by the ASX,[75] or
  - (c) at the discretion of producers.
- material intra-year changes in reserves and resources estimates should be reported, and if so, what the definition of 'material change' should be.

Most stakeholders were generally supportive of the proposal to require this information to be reported annually. AGL, however, suggested an alternative approach in which new quantities would be reported annually, with updates to the initial reporting only required if a material change had occurred. Lewis Grey Advisory, on the other hand, suggested that 2P reserves be reported every 6 months, consistent with DNRME requirements.

As to the timing of reporting, none of the producers that responded to this question supported the adoption of a fixed date. Most stated a preference to be able align the annual reporting with their existing reporting obligations to the ASX and/or DNRME. In contrast to producers, other stakeholders generally supported fixed date reporting. Lewis Grey Advisory did, however, note that while a fixed date for reporting would be useful, it would be onerous for producers if it did not align with the timing of their other reporting obligations.

On the topic of material intra-year changes, producers were either:

- opposed to having to report such changes (Shell, Esso), or
- suggested that the requirement to report such changes be limited to changes that have to be reported under other obligations, such as the ASX continuous disclosure requirements or the DNRME (APPEA, APLNG, Arrow, Cooper, Origin, Santos, and Senex).

Mixed views were also expressed on this issue by other stakeholders. Chemistry Australia, EnergyAustralia, Geoscience Australia and Lewis Grey Advisory, for example, supported intra-year updates, while Australian Paper thought that annual reporting at a fixed date would be sufficient. Geoscience Australia also suggested that any provision for the reporting of intra-year changes should include any revisions reported by foreign-listed producers to foreign securities exchanges.[76]

As to the definition of 'material change' for any intra-year reporting, Lewis Grey Advisory, Australian Paper and Cooper Energy though that definition should take into account the

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[73] ibid.

[74] *Petroleum and Gas (General Provisions) Regulation 2017* (Qld), s. 43.

[75] ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.39.1.

[76] Geoscience Australia, Response to Consultation Paper, 15 March 2019, p. 10.

impact on the market, rather than just the percentage change in the producer's reserves and resources. AGL, on the other hand, suggested it should be defined as a 20 per cent change.

Final recommendations

Having regard to the feedback provided by stakeholders, the ACCC recommends that the information set out in sections 2.1.2-2.1.5 be reported to AEMO on an annual basis. The ACCC also recommends that:[77]

(a) if a producer reports revised reserves or resources estimates (see sections 2.1.2-2.1.3) to the ASX, a government agency or within a public statement[78], then it should report the revised estimates (including an explanation for any revisions and any consequential changes to a field's development status) to AEMO at the same time

(b) if there is a material change in a producer's reserves or resources estimates (see sections 2.1.2-2.1.3) arising as a result of one of the following factors, then it should report the revised estimates (including an explanation for any revisions and any consequential changes to a field's development status) to AEMO as soon as practicable:

- acquisitions and divestments
- re-evaluations of reserves and resources
- discoveries of new reserves and resources.

In relation to (b), the ACCC recommends that the term 'material change' be defined as a change of 50 PJ or more in a producer's reserves or 2C resources (measured across the producer's portfolio rather than at a field level). In the ACCC's view, a threshold expressed in petajoules will better capture changes that are material to total east coast reserves, in comparison to a threshold expressed in terms of the percentage change in an individual producer's reserves and resources. The way in which this threshold would work, is that if a re-evaluation, new discovery or acquisition/divestment results in a producer's reserves or 2C resources changing by 50 PJ or more across the east coast and Northern Territory, then that producer would be required to report revised reserves and resources estimates (for each affected field individually) to AEMO.

As to the timing of annual reporting, the ACCC recommends that producers have the discretion to determine when the information is reported, rather than being required to report at a fixed date. In combination with the requirements to report intra-year changes set out above, this should provide a sufficiently accurate point-in-time picture of reserves and resources. In particular, the key benefit of fixed date annual reporting – that it would account for acquisitions and divestments without double- or under-counting – is also achieved by the requirement for intra-year reporting as set out above. Fixed date annual reporting therefore offers minimal benefit in the presence of the requirement to report on these changes intra-year.

Discretion with respect to the timing of annual reporting will minimise compliance costs for producers, because it will allow producers to align their Bulletin Board reporting obligations with other reporting obligations. It will therefore avoid producers having to re-evaluate their reserves and resources within the year.

[77] Any revisions should be reported using the recommended reporting framework.

[78] For example, a statement to another securities exchange or a media release issued by the producer.

2.2.6. Evaluation requirements

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the proposal to require reserve and resource estimates to be prepared by, or under the supervision of, an independent qualified petroleum reserves and resources evaluator.

Producers' views on this issue were mixed. APLNG, Arrow, Origin and Santos, for example, supported the proposal. Shell, Senex, Esso and Cooper Energy, on the other hand, were opposed to the proposal because of the cost involved. Senex, Esso and Cooper Energy also noted that qualified internal evaluators should be allowed to prepare the estimates, in the same way that they can under the ASX listing rules. [79]

Other stakeholders generally supported the independence requirement. Geoscience Australia also suggested an alternative approach in which the supervisory agency would be able to commission an independent audit of a producer's reserve and resource estimates. AGL suggested an alternative approach in which independent evaluation would be required for a field's initial estimates, with further independent evaluation not required unless a material change occurs.[80]

Final recommendations

This part should be read in conjunction with section 3.3.2, in which the ACCC separately deals with the question of whether a particular key element of the estimation process – the determination of the gas price assumptions to be used in the estimation of uncontracted reserves and resources – should be subject to an independent verification requirement.

The ACCC has considered the feedback provided by stakeholders and while its preference would be for an independent petroleum reserves and resources evaluator to conduct or oversee the estimation process, it understands that this requirement will impose costs on those producers that do not currently engage such an evaluator. The ACCC therefore recommends the adoption of a similar approach to that set out in the ASX listing rules. That is, reserve and resource estimates must be prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator[81] and if the evaluator is an employee, this must be disclosed.

To impose some additional discipline on producers when preparing their reserves and resources estimates, the ACCC also recommends that the AER[82] have the discretion to require a producer to:

- retain a suitably qualified independent petroleum reserves and resources evaluator to conduct an audit of their reserves and resources estimates
- publish the outcomes of the audit where it considers it appropriate.

Such an audit could, for example, be required if there was a significant change in reserves and/or resources or the gas price assumptions underpinning these estimates. It could also be undertaken on a periodic basis.

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79 In relation to qualifications: see ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.41-5.44.

80 AGL, Response to Consultation Paper, 13 March 2019, p. 5.

81 Defined as: A member of good standing of a professional organisation of engineers, geologists or other geoscientists whose professional practice includes petroleum reserves and contingent resources evaluations and/or audits. The professional organisation must have disciplinary powers, including the power to suspend or expel a member.

82 As stated in section 1.3, the AER will become responsible for monitoring producers' compliance with the obligations and the reporting framework.

The inclusion of this audit power in the reporting framework is intended to provide market participants and policymakers with more confidence in the estimates that are reported, while also minimising the reporting costs for producers (i.e. because an audit is likely to occur on a less frequent basis).

3. Reserves and resources estimation requirements

Reserves are defined by the PRMS as those quantities of gas that are "commercially recoverable" and the producer has demonstrated a "firm intention to proceed with the development".[83] The assessment of whether quantities are commercially recoverable requires a range of assumptions to be made about forecast conditions. Assumptions must, for example, be made about the costs that are expected to be incurred in bringing the gas to market, the prices expected to be received from the sale of the gas and the taxes and/or royalties expected to be paid. Of particular importance in this context are the assumptions that must be made about the prices that will be received from the sale of the gas.

The importance of this assumption was highlighted in the 2015 Inquiry when a major producer wrote down its reserves by approximately 20 per cent following the adoption of lower oil and gas prices assumptions.[84] While the potential for a write-down had been anticipated by some, the scale of the write-down came as a surprise to market participants because they did not have a good understanding of the sensitivity of the producer's estimates to the underlying price assumptions. Importantly, the issue highlighted by this example is not unique to this producer. Rather, it is an issue that affects all the reserve estimates reported by producers in Australia.

The need for greater transparency in this area has been reinforced in the ACCC's current Inquiry, with information provided by producers indicating that the gas price assumptions underpinning their reserves estimates can vary significantly.[85] For example, the gas price assumptions underpinning contracted reserves ranged from $2.65/GJ to $10.58/GJ and for uncontracted reserves ranged from $3.45/GJ to $14.50/GJ.[86, 87] The significant variation in these assumptions reinforces the need for the reporting framework to:

- provide greater clarity on the manner in which reserves are to be estimated and how the gas price assumptions used in the estimation of reserves are to be determined
- provide for greater transparency and oversight of the assumptions underpinning reserves estimates and the sensitivity of reserves estimates to the gas price assumptions.

It is for this reason that the ACCC is recommending that the reporting framework set out:

- the manner in which reserves are to be estimated
- how the gas price assumptions used in the estimation of reserves are to be determined
- the disclosure requirements associated with these gas price assumptions.

In a similar manner to other aspects of the proposed reporting framework, the development of this aspect of the reporting framework has been guided by the objectives set out in box 1.1. The ACCC has also had regard to the PRMS (see box 3.1) and the approaches that have been employed by other Australian and international agencies (see appendix A).

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83 SPE, PRMS, June 2018, p. 6.

84 The producer in question was Santos. At the time, Santos noted the reduction was "primarily due to the adoption of lower oil and gas price assumptions and the consequent removal or reclassification of sub economic projects". See Santos, *Reserves Statement for the year ending 31 December 2015*, 19 February 2016, p. 2.

85 ACCC, *Gas inquiry 2017-2020 interim report*, December 2018, pp. 49-50.

86 ibid.

87 In the case of contracted reserves, producers noted that their assumptions were based on the prices specified in the relevant GSAs. While for uncontracted reserves, producers typically noted that their assumptions were based on an estimate or a forecast of a market price for gas at a particular location and point in time, which were calculated using either:

- an oil-linked pricing mechanism, the application of which required forecasts of an oil price and exchange rates, or
- a domestic 'market price' estimate (e.g. published by AEMO, brokers and in other industry reports).

ACCC, *Gas inquiry 2017-2020 interim report*, December 2018, pp. 49-50.

Box 3.1: Relevant PRMS concepts

The PRMS provides limited guidance on the gas price assumptions to be used when estimating reserves and resources. The only guidance that is provided is that the assumptions should be considered “reasonable to exist throughout the life of the project” and should, where relevant, take into account the price specified in GSAs or hedges.[88] Some more general guidance is provided in relation to the commerciality assessment: [89]

> *“Economic viability is tested by applying a forecast case that evaluates cash-flow estimates based on an entity’s forecasted economic scenario conditions (including costs and product price schedules, inflation indexes, and market factors)…*
>
> *Forecasts based solely on current economic conditions are estimated using an average of those conditions (including historical prices and costs) during a specified period. The default period for averaging prices and costs is one year. However, if a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified…*
>
> *…*
>
> *Alternative economic scenarios may also be considered in the decision process and, in some cases, may supplement reporting requirements. Evaluators may examine a constant case in which current economic conditions are held constant without inflation or deflation throughout the project life.”*
>
> *Evaluations may also be modified to accommodate criteria regarding external disclosures imposed by regulatory agencies … External reporting requirements may also specify alternative guidance on the definition of current conditions or defined criteria with which to evaluate Reserves.”*

The remainder of this section provides an overview of the stakeholder feedback and the ACCC’s final recommendations on this aspect of the reporting framework.

3.1. Summary of ACCC’s initial proposal and stakeholder feedback

In the consultation paper the ACCC proposed that producers be required to:

(a) estimate their reserves and resources on the basis of forecast economic conditions

(b) distinguish between contracted and uncontracted reserves when determining what gas prices to assume when estimating their reserves and resources and, in the case of:

- contracted reserves, base the assumption on the prices specified in relevant GSAs
- uncontracted reserves, base the assumption on the price the producer expects to receive for the gas and disclose the information set out in (c) (referred to as ‘Option 2’ in the consultation paper, to distinguish it from Option 1 (common reference gas price) and Option 3 (producer determined price but no disclosure))

(c) disclose the following information when reporting their reserves and resources:

- the gas price range within which there would be no material change in 2P reserves
- the sensitivity of the 2P reserve estimates to a +/-10 per cent change in the gas price range
- a description of the method used to determine the gas price range and any other assumption made about economic conditions that influenced the range
- an explanation of any changes made to the gas price range from the prior year.

Tables 3.1 provides a snapshot of the feedback provided in response to these proposals, while table 3.2 outlines the feedback provided on compliance costs.

[88] SPE, PRMS, June 2018, pp 17-18.

[89] Ibid.

Table 3.1: Summary of feedback on the manner in which reserves and resources are to be estimated

	Basis on which reserves/resources to be estimated	Gas Price Assumptions		Disclosure Requirements			
		Contracted reserves	Uncontracted reserves and resources				
	Forecast economic conditions	Prices in relevant GSAs	Producers to determine forecast gas price and disclose specified information (Option 2)	Gas price range within which there would be no material change in 2P reserves estimates	Sensitivity of 2P reserves to a +/-10 per cent change in gas price range	Description of method used to determine price range	Explanation of changes to gas price range from prior year
ACCC proposal			Option 2				
Producers							
APPEA	n.a.		Option 3 (producers determine but no disclosure)				
APLNG		Does not use separate forecasts for contracted vs uncontracted	Option 3 (producers determine but no disclosure)				
Arrow			Option 3 (producers determine but no disclosure)				
Cooper			Option 3 (producers determine but no disclosure)				
Esso	Supports use of common forecasts based on publicly available forecasts	n.a.	Option 1 (common price assumptions)				
Origin		Does not use separate forecasts for contracted vs uncontracted	Option 2	Disclosure of information relating to the underlying price assumptions	n.a.	n.a.	n.a.
Santos			Option 2 (disclosure of high level assumptions only)				
Senex			Option 3 (producers determine with no disclosure)				
Shell			Option 3 (producers determine with no disclosure)				
Retailers							
AGL			Option 2	n.a.	n.a.	n.a.	n.a.
Energy Australia	n.a.	n.a.	Option 2	n.a.	n.a.	n.a.	n.a.
Gas users							
Australian Paper			Option 2				
Chemistry Australia			Option 2				
EUAA			Option 2		Agrees with proposal but noted that the range may be sufficient		
Other							
Geoscience Australia			Option 2	Full disclosure of assumptions underlying reserves estimates			

Table 3.2: Stakeholder feedback on costs of complying with the proposed reporting requirements

	Incremental costs	Other feedback
Producers		
APLNG	*"APLNG estimates that the proposed reporting requirements…will add multiple additional* [person]*-months by its independent qualified evaluators for each change in requirements plus any systems re-design work, which we have not yet attempted to quantify"*	*"APLNG's biggest concern would be the added confusion to market participants caused by having multiple reserve reports using different prices, and the need for APLNG to constantly reconcile the differences. APLNG believes this would not assist with market transparency."*
Arrow	Noted that it is difficult to measure the incremental costs at this stage	Suggested costs could be reduced if information could, in the case of joint ventures, be reported by the operator rather than by each producer.
Cooper Energy	n.a.	Suggested the adherence to PRMS guidelines and ASX listing rules as applicable.
Esso	*"High-level estimate of A$100k per year on the assumption that the submission date is concurrent with existing SEC reporting obligations (calendar year)."*	*"Esso believes producers should be responsible for determining the forecast gas prices they will assume when estimating uncontracted reserves but not be required to disclose their assumptions."*
Origin	*"Origin is yet to fully evaluate the costs that would be incurred in complying with the proposed reporting framework….We estimate the staffing requirements would likely increase by around two weeks for every additional change that represents a significant deviation from existing reporting practices."*	Suggested that maintaining consistency with the ASX framework would reduce compliance costs and the regulatory burden.
Santos	*"Incremental costs are minimal."*	Suggested that reporting costs could be minimised if reserves and resources information was reported at basin level.
Senex	n.a.	*"Use the existing regulation, PRMS 2018, as the standard for all organisations and ensure that these estimates are made by qualified evaluators."*
Shell	Noted that the most significant additional cost would be developing a gas price range and added that: *"Development of this additional information would create multiple times the number of man-hours associated with current internal reporting processes, spread across a wide range of subject-matter experts, with a potential value of [c-i-c]."*	n.a.
Other Stakeholders		
AGL	*"Approximately [c-i-c] for a simple review but a portfolio basis would be substantially more expensive and one that cannot be estimated at this time."*	*"A simplification of the gas price range calculations would be helpful and reduce costs."*
EUAA	*"We do not see significant compliance costs given reserves estimation will build on, rather than replace current processes e.g. based on forecast economic conditions."*	n.a.
Chemistry Australia	*"Given this information is already developed for producers own use, and this reform exercise is about eliminating information asymmetry, the cost of disclosing and providing it to regulators is likely to be minimal."*	n.a.

As table 3.1 highlights, stakeholders were generally supportive of the proposals to require reserves and resources estimates to be based on forecast economic conditions and for the prices assumed for contracted capacity to be based on the prices specified in GSAs. While the majority of stakeholders also agreed that producers should be responsible for determining the price assumptions for uncontracted capacity, a large number of producers were opposed to the associated disclosure requirements. Apart from the costs associated with these disclosure requirements, producers were concerned that the disclosure of some information could be construed as price signalling and could also affect a listed entity's share price.

Further detail on the feedback provided by stakeholders on this aspect of the reporting framework is provided below, along with the ACCC's final recommendations. Before moving on, it is worth noting that diverse views were expressed on the potential compliance costs associated with this aspect of the reporting framework. Santos and Esso's responses, for example, suggest the incremental costs will be relatively low (~$100 000), while another stakeholder suggested the costs would be substantially more.

3.2. Manner in which reserves and resources are to be estimated

ACCC's initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on its proposal to require producers to estimate reserves and resources on the basis of forecast economic conditions. As table 3.1 highlights, there was broad support for this proposal. Esso did, however, suggest going one step further by requiring all producers to use a common set of publicly available price, foreign exchange and escalation forecasts. Geoscience Australia also noted that unless the forecast economic conditions to be assumed by producers are stipulated (e.g. by AEMO), then producers should be required to report the assumptions they have made. Geoscience Australia also suggested that a standardised forecast period be assumed (e.g. five years) to enable comparisons to be made over time.

Final recommendations

Consistent with the feedback provided by stakeholders, the ACCC recommends that producers be required to estimate their reserves and resources on the basis of forecast economic conditions. In the ACCC's view, the use of forecast economic conditions better reflects the forward-looking nature of the commerciality assessment producers are required to carry out, both when estimating reserves and when deciding whether or not to proceed with the development of the reserves. It can therefore be expected to provide a better insight into the future development of reserves and supply outlook than the alternatives.

The ACCC understands that the proposal to use forecast economic conditions is consistent with the approach that producers in the east coast are currently employing. The use of this approach should therefore minimise compliance costs (i.e. because producers will only have to develop one set of reserves estimates for reporting, planning and investment purposes). It will also ameliorate the risk of conflicting reserves estimates being reported by producers, which could confuse market participants and policymakers.

As to the suggestion by Esso and, to a lesser extent, Geoscience Australia that producers be required to use a common set of forecasts, the ACCC notes that while it can see some merit in this approach, there no single source of forecasts that could be used for this purpose. The ACCC would expect, however, producers to base their growth, inflation, foreign exchange, oil price and other key economic forecasts on those published by reputable economic commentators and agencies, such as the Reserve Bank of Australia, the Australian Bureau of Statistics, Commonwealth and State Treasuries. While the ACCC is not proposing to mandate the use of these sources, it does recommend that producers be required to report the key economic assumptions underpinning their reserves and resources estimates and the source of these assumptions.

3.3. Gas price assumptions and disclosure requirements

In keeping with the approaches employed in the PRMS and other jurisdictions (see appendix A), the ACCC has drawn a distinction between the gas price assumptions to be used to estimate contracted reserves and those used to estimate uncontracted reserves and resources. These two situations are therefore considered separately below.

It is worth noting that APLNG and Origin raised some concerns with the proposal to draw this distinction, because they are currently using a blended price forecast, rather than separate forecasts for each type of reserve. While the use of this blended price forecast may yield a similar result to the use of separate prices for contracted and uncontracted reserves, this approach is at odds with what other producers in the east coast have informed the ACCC they are doing and is also at odds with the PRMS and the approaches employed in other jurisdictions. The ACCC does not therefore support the use of this blended price approach.

3.3.1. Contracted reserves

ACCC's initial proposal and stakeholder feedback

In the consultation paper the ACCC sought feedback on the proposal to require producers to use the prices specified in the relevant GSAs when estimating contracted reserves and to account for the operation of price escalation mechanisms and contract extension provisions:

Stakeholders generally supported this proposal, although some noted that there may be some uncertainty surrounding the operation of the escalation mechanism, or whether a contract extension would be exercised. To address this uncertainty, AGL suggested that any assumptions made by producers meet the reasonableness test in the PRMS (e.g. there must be a reasonable expectation that the extension will occur).

Final recommendations

Having regard to the feedback provided by stakeholders, the ACCC recommends that producers be required to use the gas prices specified in relevant GSAs when estimating their contracted reserves and to also account for the operation of:

- the price escalation mechanisms specified in the relevant GSA over the forecast period
- contract extension provisions specified in the relevant GSAs over the forecast period, if there is a *reasonable expectation*[90] that the GSAs will be extended and the prices (or pricing mechanisms) to apply in the extension period have already been determined.

This recommendation is consistent with the approach set out in the PRMS and the approach employed by the Canadian Securities Administrators (CSA) (see Appendix A). It is also consistent with the approach that producers informed the ACCC they use, when it conducted its detailed review of reserves and resources in the latter half of 2018.[91] The adoption of this approach should therefore minimise compliance costs.

The ACCC has considered whether the gas price assumptions underpinning contracted reserves estimates should be disclosed by producers. However, in its view this is unnecessary because any changes to the price assumptions should not affect these reserves

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[90] As noted in the PRMS, there should be a reasonable expectation that an extension will occur. This expectation may be based on the status of renewal negotiations and/or historical treatment of similar agreements.
See SPE, PRMS, June 2018, p. 24.

[91] ACCC, *Gas Inquiry 2017-2020 Interim report*, December 2018, ch. 2.

(i.e. because producers have a contractual obligation to supply at the price specified in the GSA).

3.3.2. Uncontracted reserves and resources

ACCC’s initial proposal and stakeholder feedback

In the consultation paper, the ACCC sought feedback on the following options for determining the gas price assumptions to be used when estimating uncontracted reserves:

1. Require all producers to use a common reference gas price (Option 1).
2. Accord producers responsibility for determining their own gas price assumptions and require some disclosure of these assumptions (Option 2).
3. Accord producers responsibility for determining their own gas price assumptions but don’t require those assumptions to be disclosed (Option 3).

Of the options listed above:

- Option 1 was supported by Esso, who noted that it would provide a “common basis for all producers to use and allows common comparison across companies”.[92] Other stakeholders, on the other hand, raised a number of concerns with this option. Origin, for example, noted that adopting a common price assumption that is “inconsistent with the producer’s own view of development economics would simply result in the disclosure of a misleading set of estimates, as they would have no relevance to the producers’ planning and investments decisions”. [93] Similar views were expressed by other producers, including APPEA who noted that this option would “add to market confusion and producers costs” because they would have to maintain different reserve estimates.[94, 95]
- Option 2 was supported by Origin, AGL, EnergyAustralia, Australian Paper, the EUAA, Chemistry Australia and Geoscience Australia on the basis that it would provide the market with some indication of the sensitivity of the reserves estimates to the price assumptions. Santos also supported some level of disclosure, but suggested that producers only be required to disclose their assumptions at a high level (e.g. if prices are assumed to be oil linked) because, in its view, more detailed disclosure might be considered price signalling. Other producers, on the other hand, were opposed to disclosing “commercially sensitive” information. Shell, for example, noted that “price assumptions are highly commercially sensitive as they are a major factor in internal decision making in relation to a range of matters”.[96] This view was echoed by a number of other producers. APLNG also stated that disclosing the price assumptions could place producers at a disadvantage in negotiations.
- Option 3 was supported by APPEA, APLNG, Arrow, Chevron, Cooper Energy, Senex and Shell on the basis that it would not require the disclosure of “commercially sensitive” information. Other stakeholders, on the other hand, were concerned about the lack of transparency associated with this option.

The ACCC also sought feedback on the disclosure requirements for Option 2 and, in particular, the proposal to require producers to disclose the following in relation to the gas price assumptions underpinning their estimates:

(a) the price range within which there would be no material change in 2P reserve estimates

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[92] Esso, Response to Consultation Paper, 12 March 2019, p. 9.

[93] Origin, Response to Consultation Paper, 15 March 2019, p. 8.

[94] For example, one set of reserve estimates would be reported to the Bulletin Board while another set would be used for internal planning and investment purposes and reporting to government agencies.

[95] APPEA, Response to Consultation Paper, 12 March 2019, p. 6.

[96] Shell, Response to Consultation Paper, 12 March 2019, p. 5.

(b) the sensitivity of 2P reserves estimates to a +/-10 per cent change in the range reported in (a)

(c) a description of the method used to determine the price assumptions and why the assumptions can be considered reasonable

(d) an explanation of any changes made to the price assumptions from the prior year and why they were made.

This proposal was supported by Australian Paper, Chemistry Australia and the EUAA, while Geoscience Australia was of the view that there should be full disclosure of the assumptions underlying reserves estimates. In contrast to these stakeholders, most producers were opposed to disclosing any of the information listed in (a)-(d). Some of the matters that producers cited in support of their position were that:

- it would be complex and "administratively burdensome" to carry out the analyses required by (a) and (b)[97]
- even if a range was published it may be interpreted as price signalling[98]
- the disclosure of information in (a) and (b) may affect a listed entity's share price and company valuation if interpreted incorrectly[99]
- prices are only one factor affecting reserves and resources estimates and "should not be focused on to the exclusion of everything else." [100]

Elaborating further on the first of these points, Shell noted the following:[101]

> *"Reserve estimation is a lengthy process based around a set of technical and non-technical assumptions, including price. For CSG projects, assessing the impact of a reduction in price would involve: re-evaluation of all future development activity to determine whether it is still economic,*
> *re-evaluation of economic cut-off for all current wells and infrastructure and re-assessment of economic end of field life. To determine the price level at which there is no material reduction in reserves would require multiple iterations to determine a price/volume relationship.*
>
> *Estimating reserve upside from a price increase is harder. Additional wells in existing fields may become economic, but as they are excluded from field development plans they would require estimated drilling schedules and costs to be prepared specifically for this purpose. New fields may become economic, but these will not have the level of forecast maturity consistent with 2P reserves. Again, multiple iterations would be required to determine at what price point a material reserve increase occurs."*

In addition to these matters, the ACCC sought feedback on whether the gas price assumptions used by producers should be subject to any form of reasonableness test and oversight by the AER. While EnergyAustralia, Chemistry Australia and the EUAA supported the application of a reasonableness test, most producers thought it was unnecessary because they claim not to have an incentive to misstate their reserves and resources. Santos also thought this was unnecessary where a producer's gas price assumptions are independently validated by an external auditor, but noted that there may be value in applying such a test where a producer's assumptions have not been independently validated.

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97 See for example, Esso, Response to Consultation Paper, 12 March 2019, p. 11.

98 See for example, the response received from Santos.

99 See for example, the response received from Senex.

100 See for example, Cooper Energy, Response to Consultation Paper, 12 March 2019, p. 13.

101 Shell, Response to Consultation Paper, 12 March 2019, p. 13.

Final recommendations

Consistent with the recommendation that reserve estimates be based on forecast economic conditions, the ACCC recommends that the gas price assumptions underpinning the estimate of uncontracted reserves and resources be based on a forecast of the price that producers expect to receive for the gas.

As to the options for determining these gas price assumptions, the ACCC notes that while its preference would be the adoption of a common price approach (i.e. Option 1), it recognises that there are a number of practical limitations with this option. The most significant of which is that there is currently no widely accepted external reference price that could be used for this purpose. In addition to this issue, mandating the use of a common reference price could, as a number of stakeholders pointed out, result in producers having to maintain two sets of reserves estimates. One of which would be reported on the Bulletin Board and the other used by producers for planning and investment decisions and potentially reported to the ASX by ASX listed entities. The lack of alignment between these estimates could result in differences between the market's view and the producer's view of the future prospects of reserves and mislead the market about the supply outlook.

Given the issues outlined above, the ACCC has considered the other two options listed above, both of which would involve according producers responsibility for determining their own gas price assumptions. The main concern the ACCC has with Option 3 is that market participants and policymakers would have no understanding of the sensitivity of the reserves estimates to the gas price assumptions. There would also be no oversight by either the market or a regulator of the prices that have been assumed, which could affect the confidence that market participants and policymakers have in the reserves and resource estimates.

In contrast to Option 3, Option 2 would require a greater level of transparency of the gas price assumptions underpinning the reserves and resources estimates, which would provide more insight into the sensitivity of these estimates to these assumptions. It would also impose more discipline on producers when determining their gas price assumptions, because the market would be able to readily determine if the assumptions employed by particular producers are reasonable or not.

While Option 2 does not suffer from the same limitations as Option 3, the ACCC understands the concerns that have been raised by some stakeholders about the potential for the disclosure of individual producers' price assumptions to facilitate coordinated conduct. To ameliorate this risk, the ACCC originally suggested that producers only report the price range within which there would be no material change in 2P reserve estimates. The feedback provided by some stakeholders, however, suggests that even reporting at this level could have a deleterious effect on competition. The ACCC has therefore considered whether the outcomes that were envisaged under Option 2 (i.e. improving market efficiency by imposing more discipline on producers when estimating their reserves and resources and providing some insight into the sensitivity of these estimates to gas price assumptions) could be achieved in another way.

As noted above, one of the key strengths of Option 2 is that transparency of gas price assumptions imposes some discipline on producers to adopt reasonable assumptions when estimating their reserves and resources. To mimic the same outcome, the ACCC recommends that:[102]

- producers be required to:

[102] These recommendations should be read in conjunction with the recommendation made in section 2.2.6 for the AER to have the power to require that a producer's reserves and resources estimates be independently audited. Review of the gas price assumptions used would be within the scope of such an audit.

- have their gas price assumptions verified by a suitably qualified independent petroleum reserves and resources evaluator as falling within the range of gas price forecasts used or adopted by such evaluators, or published by reputable independent Australian sources of gas industry forecast information for Australia[103, 104]
- report their actual gas price assumptions to the AER, along with a description of how the assumptions were derived, so that the AER can oversee compliance with this requirement[105]

- the AER be required to publish the gas price assumptions provided by producers annually on an anonymised and aggregated basis.[106, 107]

The first of these requirements, which is akin in many ways to the approach employed by the CSA (see Appendix A), should provide market participants and policymakers with more confidence in the reserves and resources estimates. Their confidence will be further strengthened by the requirement for producers to report their assumptions to the AER and for the AER to publish the assumptions on an aggregated and anonymised basis.[108] The ACCC understands that there will be costs associated with this reporting requirement, however, the discipline imposed on producers should yield more robust estimates of reserves and resources. In this regard it is worth noting that while the involvement of an independent evaluator in this process may appear to contradict the recommendation on the evaluation requirements, the scope of the independent evaluator's role in this case is just to verify the prices assumed. It is not to oversee the full estimation process. The costs associated with this requirement are therefore expected to be relatively low.

The other key strength of option 2 is that it provides market participants and policymakers with a better understanding of the sensitivity of the reserves and resources estimates to changes in gas prices. While there was some opposition from producers to reporting on the sensitivity of their estimates, in the ACCC's view it is a critical element of the reporting framework. Having said that, the ACCC recognises that there may be some commercial sensitivities associated with reporting this information on an individual producer basis (particularly for listed entities). The ACCC recommends therefore that:

- producers be required to report to AEMO on the sensitivity of their 2P reserves estimates to a +/-10 per cent change in their gas price assumption
- before publishing the information on the Bulletin Board, AEMO aggregate the results (e.g. by basin, region or other aggregation level that encompasses at least three producers).

103 The forecasts could, for example, be based on forecasts developed by AEMO for the GSOO, or the LNG netback price to be published by the AER.

104 Producers would then have to publish the statement from the independent evaluator confirming this verification.

105 This includes both compliance with the requirement to obtain independent verification, and compliance with the requirement that the price assumptions meet the stated test (i.e. that they fall within the range described).

106 If the information is aggregated across at least three producers that are operating independently (e.g. they are not related parties and are not operating together in a joint venture), it will not be possible for one party to work out the actual quantity of the contracted reserves of another party without access to the private market information of the other party.

107 A similar approach was taken in the ACCC's December 2018 report, which showed the spread of price assumptions adopted by producers for their uncontracted reserves.

108 Note that the requirement for the AER to publish this information is in keeping with the ACCC's recommendations that the AER also become responsible for reporting on the prices agreed to under longer-term GSAs and the LNG netback price.

Appendix A: Reserves and resources reporting frameworks employed by other agencies

A.1. Reporting frameworks employed by other agencies

Table A.1 provides a summary of the reporting frameworks employed by:

- the National Offshore Petroleum Titles Administrator (NOPTA)[109]
- the Queensland Department of Natural Resources, Mines and Energy (DNRME)[110]
- the Australian Securities Exchange (ASX)[111]
- the United Kingdom's Oil and Gas Authority (OGA)[112]
- the Canadian Securities Administrators (CSA)[113]
- the United States Securities and Exchange Commission (SEC).[114]

While not shown in the table, there are a number of other areas in which the reporting frameworks employed by other agencies require additional information. For example:

- NOPTA requires information on exploration and development activities carried out in the previous year and planned for the following year,[115] while the SEC requires disclosure of investments and progress made to convert proved undeveloped reserves into proved developed reserves[116]
- the ASX,[117] SEC[118] and CSA[119] require detail on why undeveloped reserves have not been developed after a specified period of time
- NOPTA requires production forecasts to be disclosed for the life of the field.[120]

It is worth noting that the objectives of some of these frameworks differ from the ACCC's objectives in developing the reporting framework, which are to:

- provide market participants and policymakers a better understanding of the supply outlook and, in so doing, enable more informed and efficient consumption, exploration, production, infrastructure investment and policy decisions to be made
- signal changes to the supply outlook and potential supply problems in a more timely and effective manner and, in so doing, enable the market to respond more efficiently to changing conditions

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109 See *Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011* (Cth), Part 3; and NOPTA, *Annual tittle assessment report* (ATAR) *templates*, http://www.nopta.gov.au/forms/reporting-templates.html (herein referred to collectively as NOPTA ATAR requirements).

110 *Petroleum and Gas (General Provisions) Regulation 2017* (Qld), s. 43 and DNRME, *Petroleum and gas reporting guideline*, October 2018. See also https://data.qld.gov.au/dataset/petroleum-gas-production-and-reserve-statistics (herein referred to collectively as DNRME requirements).

111 ASX, *Listing Rules – Chapter 5: Additional reporting on mining and oil and gas production and exploration activities* (herein referred to as Chapter 5 Listing Rules), 1 July 2014 and ASX, Guidance Note 32, 1 December 2013.

112 OGA, UK Oil and Gas Reserves and Resources as at end 2017, November 2018.

113 CSA, National Instrument F1-101, Standards of Disclosure for Oil and Gas Activities, 1 July 2015 and CSA, Companion Policy 51-101, *Standards of Disclosure for Oil and Gas Activities,* 1 July 2015 (herein referred to as CSA requirements).

114 SEC, *Modernization of Oil and Gas Reporting Final Rule,* Federal Register Vol. 74, No. 9, 14 January 2009, SEC, Code of Federal Regulations: Title 17 Chapter II, Regulation S-K, part 210.4-10 and Regulation S-X, subpart 229.1200, accessed 20 December 2018 (herein referred to as SEC requirements).

115 See NOPTA ATAR requirements (see footnote109).

116 SEC, *Code of Federal Regulations: Title 17 Chapter II, Regulation S-X*, s. 229.1203.

117 ASX, *Chapter 5 Listing Rules*, 1 July 2014, r. 5.39.4.

118 SEC, *Code of Federal Regulations: Title 17 Chapter II, Regulation S-X*, s. 229.1203.

119 See CSA, *Form 51-101F1 – Statement of Reserves Data and Other Oil and Gas Information*, item 5.1.

120 See NOPTA ATAR requirements (see footnote109).

- reduce the information asymmetry that currently exists between gas suppliers and users and, in so doing, enable users to negotiate more effectively with suppliers.

In contrast, the objectives of:

- NOPTA are to advise on and administer the offshore petroleum titles regime to support the effective regulation of oil and gas resources consistent with good oil field practice and optimum recovery[121]
- the OGA are to maximise the economic recovery of the UK's oil and gas resources[122]
- the ASX, CSA and SEC are to enable capital market participants to make informed investment decisions and to value listed gas producers.[123]

The differences in objectives mean that some aspects of these other reporting frameworks are more or less relevant to the development of this reporting framework than others.

121 NOPTA, *Corporate Plan 2017-2020,* July 2017.

122 See https://www.ogauthority.co.uk/about-us/what-we-do/.

123 See for example, *SEC Modernization of Oil and Gas Reporting Final Rule*, Federal Register Vol. 74, No. 9, 14 January 2009.

Table A.1: Comparison of reporting requirements

	Information Reported									Bases on which Information Reported				
	Reserves			Resources				Movement (mvt) in reserves	Contracted 2P reserves	Classification System	Quantities	Reporting Level	Frequency	Evaluation requirements
	1P	2P	3P	1C	2C	3C	Prospective							
Australian agencies														
ASX[124]	Broken down by developed and undeveloped reserves for each category Also broken into unconventional quantities		Optional	Optional				Mvt in 1P, 2P and 2C (if reported) and explanation of material change	n.a.	PRMS	Net revenue interest in sales or raw quantities (if raw non-sales gas must also be reported)	Geographic area[125]	Annual (part of annual financial report)	Prepared by, or under supervision, of qualified evaluator
NOPTA[126] **(not public)**	Optional	Total only	Optional	Optional	Total only	Optional		n.a.	n.a.	PRMS	n.a.	Pools within each field	Annual (anniversary of title)	n.a
DNRME[127]	Where available	Total only	Where available	Where available				n.a.	n.a.	PRMS	Total volume in each reservoir	Reservoirs within each field	Six monthly but published with 6mth lag	No specific requirements but info must be auditable.
International agencies														
UK OGA[128]	Broken down by fields in production and under development			Broken down by producing fields, proposed new developments and marginal discoveries		Prospect, lead or play		Mvt in 2P reserves and 2C resources broken down into categories	n.a.	PRMS with modifications to sub-categories	n.a.	Field but aggregated to basin for publication	Annual	n.a.
US SEC[129]	Broken down by developed and undeveloped	Optional (Broken down by developed and undeveloped)		n.a.				Mvt in 1P undeveloped and reasons for mvt	Disclosure of contracted volumes[130]	Similar to PRMS	Net revenue interest in sales quantities	Country or continent	Annual (part of annual financial report)	No specific requirements
Canada CSA[131]	Broken down by developed (producing vs non-producing) & undeveloped	Total only	Optional	Optional				Mvt in 1P and 2P broken down into categories	Disclosure of contracted volumes if they protect producer from full effect of market prices	COEGH (consistent with PRMS)	Gross and net quantities	Country	Annual (part of annual financial report)	Estimates must be accompanied by report from independent qualified evaluator or auditor

124 See ASX, Chapter 5 Listing Rules, 1 July 2014.
125 The ASX provides producers some discretion to determine the geographic areas used for reporting, but has noted it should be determined having regard to the materiality of the reserves.
126 See NOPTA ATAR requirements (see footnote 109).
127 See DNRME requirements (see footnote 110). The information identified as 'Where available' is not required by the Regulations, but is referred to in the guideline as being "good industry practice".
128 See OGA requirements (see footnote 112).
129 See SEC requirements (see footnote 114).
130 If a producer is committed to provide a fixed and determinable quantity of gas under existing contracts, it must, amongst other things, disclose the quantities of gas subject to the commitment.
131 See CSA requirements (see footnote 113). The COEGH is the Canadian Oil and Gas Evaluation Handbook.

A.2. Approaches to reserves and resources estimation by other agencies

Table A.2 provides an overview of the approaches these agencies have taken in relation to reserves and resources estimation and the gas price assumptions underpinning those estimates.

Approaches employed in Australia

As table A.2 shows, the reporting frameworks currently in use in Australia do not specify how reserves are to be estimated or the gas price assumptions to be used in the estimation. It is worth noting though that in 2011-12 the ASX considered imposing more stringent requirements in this area to try and promote greater consistency in the reporting of reserves and resources. Some of the options that the ASX considered in this context, included requiring listed producers to:

- estimate their reserves and resources on the basis of:
  - future economic conditions, with the gas price assumptions to be based on the producer's reasonable forecast of future prices or the prices specified in GSAs
  - current economic conditions, with the gas price assumptions to be based on a similar historic price approach to that employed in the US
- disclose their gas price assumptions, the gas price range within which there would be no material change in reserve estimates, or the method used to derive the gas price assumptions.

Most of the stakeholders involved in the ASX's consultation process were of the view that reserves and resources should be estimated on the basis of future economic conditions rather than current economic conditions.[132] They also noted that requiring the use of historic gas prices would result in companies having to maintain more than one set of reserves estimates because the historic prices would "not align with the pricing assumptions used internally by companies for planning purposes, investment decisions and other transactions".[133]

Most stakeholders were also opposed to the requirement to disclose the price assumptions underpinning their reserve estimates because they claimed that, in the case of:[134]

- contracted reserves, the prices specified in GSAs were subject to confidentiality clauses
- uncontracted reserves, the gas price forecasts were "commercially sensitive" because they were also used for planning, investment and contract negotiation purposes.

These stakeholders were also opposed to reporting a price range, because they claimed this was also commercially sensitive information.[135] While these two options were opposed, stakeholders generally supported the proposal to include a brief explanation of the method used to determine the gas price assumptions when the reserves are first reported.[136]

It was on the basis of this feedback that the ASX decided not to impose any specific requirements on how reserves are to be estimated or the gas price assumptions to be used in the estimation. The ASX decided instead to leave this to producers and to also provide producers with some discretion as to whether they disclose the gas price assumptions underpinning their estimates, or the method used to determine the assumptions.

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132 ASX, *Reserves and Resources Disclosure Rules for Mining and Oil & Gas Companies: Report on Consultation Feedback*, April 2012, p. 20

133 ibid.

134 ibid, pp. 23-24.

135 ibid.

136 ibid.

Table A.2: Treatment of gas price assumptions in other reporting frameworks

	Basis on which reserves are to be estimated	Requirements for gas price assumptions	Disclosure requirements for gas price assumptions
Australian Agencies			
ASX	No specific requirements other than a statement in ASX Guidance Note 32 that "to the extent an estimate of petroleum reserves involves a representation about future matters, it must be based on reasonable grounds – meaning that the economic assumptions used to calculate the estimates must also be objectively reasonable".		The first time a producer reports its reserve estimates, it must disclose: [137] *"All material economic assumptions used to calculate the estimates…If those economic assumptions are commercially sensitive to the oil and gas entity, an explanation of the methodology used to determine the assumptions rather than the actual figure can be reported."*
NOPTA	No specific requirements		No disclosure requirements
DNRME	No specific requirements		No disclosure requirements
International Agencies			
UK OGA	No specific requirements		No disclosure requirements
US SEC[138]	Proved reserves **must** be estimated on the basis of current economic conditions (i.e. historic prices and costs)	Producers **must** use: (a) the prices specified in GSAs for **contracted reserves** (excluding escalations based on forecast conditions) (b) the historic 12-month average gas price for ***uncontracted reserves*** (calculated as the unweighted average of the first-day-of -month price for each month in the 12-month period ending on reporting date).	No disclosure requirements.
	Producers also have the *option* to report their reserves under alternative price and cost scenarios based on, for example, futures prices or management's forecasts.		If producers publish their reserves under alternative price scenarios, they must disclose the gas price assumptions they have used.
Canada CSA[139]	Reserves (and resources, if reported) **must** be estimated using 'forecast prices and costs.'	Producers **must** use 'forecast prices', which are defined as prices that are: (a) the prices specified in GSAs for ***contracted reserves*** (including in an extension period if likely to be extended) (b) generally accepted as being a reasonable outlook of the future[140] for ***uncontracted reserves.***	Producers are required to disclose: • the gas price assumptions (including the *benchmark reference prices*)[141] for the countries or regions in which they operate: ○ for each of at least the following five financial years ○ generally, for subsequent periods • the producer's weighted average gas price for the most recent year • the inflation, exchange rate and other forecast factors used in pricing.
	Producers also have the *option* to report their reserve under the constant case (i.e. current economic conditions are held constant without inflation over the project life)	Under the constant case option, the price must be based on: (a) the historic 12-month average gas price for ***uncontracted reserves*** (calculated in the same way as the US) (b) the prices specified in GSAs for ***contracted reserves***.	If the producer discloses a reserves estimate based on the constant case option, it must disclose the prices used in this analysis.

137 ASX, Chapter 5 Listing Rules, 1 July 2014, r. 5.31 and ASX, Guidance Note No. 32, p. 9.

138 These obligations can be found in SEC, *Code of Federal Regulations: Title 17 Chapter II, Regulation S*-K, accessed 20 December 2018, s. 210.4-10(a)(22) and 22(v) and SEC, *Code of Federal Regulations: Title 17 Chapter II, Regulation S-X*, accessed 20 December 2018, s. 229.1202(b).

139 These obligations can be found in *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activitie*s, 1 July 2015, s. 1, and *National Instrument Form 51-101F1: Statement of Reserves Data and Other Oil and Gas Information*, 1 July 2015, items 2.1, 2.2, 3.1, 3.2, 7.1 and 7.3.

140 The CSA has stated that forecast prices are likely to fail this requirement if they fall outside the range of forecasts by major independent qualified reserves evaluators or auditors, or other reputable sources. See CSA, *Companion Policy 51-101: Standards of Disclosure for Oil and Gas Activitie*s, 31 December 2015.

141 Form 51-101FI provides for the *benchmark reference prices* to be obtained from sources, such as public product exchanges or prices posted by purchasers, and also provides for these prices to be overridden by contract prices if a producer has a contractual or other obligation to supply the gas at that price.

Approaches employed internationally

In contrast to the position taken by the ASX, the instruments administered by the SEC and CSA specify the manner in which listed producers are to estimate their reserves and the gas price assumptions to be used in the estimation. While there are some similarities in the approaches employed by the SEC and the CSA, there are also some fundamental differences. These differences primarily stem from the alternative positions the SEC and CSA have taken on the way in which reserves should be estimated (i.e. current economic conditions versus forecast economic conditions), which directly affects the way in which the gas price assumptions are determined.

The SEC, for example, requires listed producers to estimate their proved reserves on the basis of current economic conditions. Consistent with this requirement, the SEC requires the gas price assumptions applied to:

- contracted reserves to be based on the prices specified in the relevant GSAs (excluding any escalations based on forecast conditions)
- uncontracted reserves to be based on the historic 12-month average gas price.

The SEC also accords producers the option to report their reserves estimates under alternative price and cost scenarios (for example, based on futures prices or management's forecasts). If producers exercise this option, they must disclose the price assumptions underpinning the alternative reserve estimates.

Some insight into the SEC's rationale for adopting this approach, can be found in the following extracts taken from the final rule on the modernisation of oil and gas reporting:

> *"We believe that the purpose of disclosing reserves estimates is to provide investors with information that is both meaningful and comparable. The reserves estimates in our disclosure rules, however, are not designed to be, nor are they intended to represent, an estimation of the fair market value of the reserves. Rather, the reserves disclosures are intended to provide investors with an indication of the relative quantity of reserves that is likely to be extracted in the future using a methodology that minimizes the use of non-reserves-specific variables. By eliminating assumptions underlying the pricing variable, as any historical pricing method would do, investors are able to compare reserves estimates where the differences are driven primarily by reserves-specific information, such as the location of the reserves and the grade of the underlying resource."*[142]
>
> *"…since the new rules and amendments require the use of a single price to estimate reserves and since that price may not be as informative of value as a futures price, the new rules and amendments also gives companies the option of providing a sensitivity analysis and reporting reserves based on additional price estimates.*
>
> *If companies elect to provide a sensitivity analysis, we expect this to benefit investors by allowing them to formulate better projections of company prospects that are more consistent with management's planning price and prices higher and lower that may reasonably be achieved. In particular, it allows companies the flexibility to communicate how their reserves would change under alternative economic conditions, including those that they may believe better reflect their future prospects."*[143]

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[142] SEC, *Modernization of Oil and Gas Reporting Final Rule,* Federal Register Vol. 74, No. 9, 14 January 2009, p. 2162.

[143] ibid, p. 2185.

In contrast to the SEC, the CSA require reserves and resources to be estimated on the basis of forecast economic conditions. Consistent with this requirement, the CSA require the gas price assumptions applied to:

- contracted reserves to be based on the prices specified in the relevant GSAs (including during an extension period if the GSA is likely to be extended)
- uncontracted reserves to be based on a forecast price that is "generally accepted as being a reasonable outlook of the future".

In addition to forecast economic conditions, Canadian producers have the option to report their reserves under the constant case scenario. The gas price assumptions in this case must be based on the prices specified in the relevant GSAs for contracted reserves or the historic 12-month average gas price for uncontracted reserves.

The other key difference between the approach employed in the US and Canada, is that the CSA requires greater disclosure of the gas price assumptions than the SEC.

Canadian listed producers, for example, are required to disclose their forecast gas price assumptions, their weighted average gas price for the most recent year and other assumptions they have used to determine the forecast prices.[144] US listed producers, on the other hand, are not required to disclose the gas price assumptions underpinning their current economic conditions based estimates. They are only required to disclose these assumptions if they decide to report their reserve estimates under alternative gas price assumptions.

[144] In addition to this information, Canadian listed producers must disclose the future net revenue attributable to the reserves and the key components of the future net revenue, including forecast revenue, operating costs, development costs, abandonment and reclamation costs, taxes and royalties. Producers must also identify and discuss in their annual reports, the significant economic factors or uncertainties that affect particular components of the reserves estimates.

Appendix B: Examples of how the reserves and resources information would be reported

Table B.1: Example of how the reserves, resources and gas field information would be reported

Basin/Field Name		Gas Field Information					Reserves									Contingent Resources (PJ)*
							1P Reserves (PJ)*			2P Reserves (PJ)*			3P Reserves (PJ)*			
Basin Name	Field Name	Location	Permit no.	Net revenue interest	Type of gas	Nature of gas field	Developed	Un-developed	Total	Developed	Un-developed	Total	Developed	Un-developed	Total	2C
XX	AA1	Cat Creek	123	x%	Conventional	Oil	5	10	15	5	10	15	5	10	15	100
YY	AA2	Dog Corner	456	y%	CSG	Dry gas	5	10	15	5	10	15	5	10	15	40

* Quantities to be based on the producer's net revenue interest in the sales quantities of gas available in the field.

Table B.2: Example of how the movement in 2P reserves information would be reported

Basin Name	Field Name	Total 2P Reserves (as at 30 June 2017)	Breakdown of movement in 2P reserves							Total 2P Reserves (as at 30 June 2018)
			Production (PJ)*	Extensions (PJ)*	Net Acquisitions (PJ)*	Reserve Upgrades (PJ)*	Reserve Downgrades (PJ)*	Other Revisions (PJ)*	Total movement in 2P reserves (PJ)*	
XX	AA1	15	-5	5	5	5	-10	-5	-5	10
YY	AA2	20	-10	10	-10	10	-5	-5	-10	10

* Quantities to be based on the producer's net revenue interest in the sales quantities of gas available in the field.

Table B.3: Example of how the development status would be reported in fields meeting materiality threshold

Basin/Field Name		2P Reserves (PJ)*				2C Resources (PJ)*				
Basin Name	Field Name	On Production	Approved for Development	Justified for Development	Total	Development Pending	Development on Hold	Development Unclarified	Development Not Viable	Total
XX	AA1	5	10	0	15	30	10	50	10	100
Likely timing of production		n.a.	Feb 2020	Feb 2023	n.a.	Feb 2025	Feb 2040	n.a.	n.a.	n.a.
Barriers to commercial recovery		n.a.				Technology under development, Pipeline to be developed Environmental Approval				

* Quantities to be based on the producer's net revenue interest in the sales quantities of gas available in the field.

Appendix C: List of submissions

Stakeholder	Submission date
AGL	13 March 2019
APLNG	12 March 2019
APPEA	16 March 2019
Arrow	12 March 2019
Australian Paper	12 March 2019
Chemistry Australia	18 March 2019
Chevron	14 March 2019
Cooper Energy	12 March 2019
EnergyAustralia	12 March 2019
Energy Users' Association of Australia	18 March 2019
Esso	12 March 2019
Geoscience Australia	15 March 2019
Lewis Grey Advisory	12 March 2019
Origin	15 March 2019
Santos	14 March 2019
Senex	12 March 2019
Shell	12 March 2019