Department of **Energy and Water Supply**

2012 Gas Market Review
Queensland

CS1645 07/12

Contents

Preface

Welcome to the third annual Queensland Gas Market Review (GMR). The GMR informs government decision-making on security of domestic gas supply, effective gas resource management and the development of a more competitive Queensland gas market.

The GMR aims to improve stakeholder market knowledge and provide transparency of views and outcomes. The 2012 GMR continues to build on the comprehensive picture and detailed analysis of the Queensland gas market provided in the previous reviews undertaken in 2010 and 2011. Forecasts for future industry growth and identification of participants' needs remain a priority.

Feedback from last year has been incorporated and the GMR continues to evolve to address gas market development and growth. Changes in the 2012 GMR are designed to provide an improved market context, capture the significant industry and market progress made in the past 12 months, provide an improved understanding of the issues impacting access to gas for domestic contracting, and increase the level of market information on these matters.

Following the 2012 Queensland state election, changes this year also include a machinery-of-government move for the office from the Mines and Energy area of the Department of Employment, Economic Development and Innovation to the Department of Energy and Water Supply. In addition, the Office of the Queensland Gas Commissioner has been renamed as the Office of the Queensland Gas Market Advisor.

This year's review has an upstream focus on the development and ownership of gas reserves, identifying domestic demand in the changing market environment and ensuring the modelling is appropriately focused on the short term as well as the longer term. Consideration is also given to the barriers that could impact reserves and future gas supplies, including Prospective Gas Production Land Reserve (PGPLR) issues.

The 2012 GMR consists of a general overview and background to the issues, a market update, a response to issues raised by the 2011 GMR, and a supply and demand review that includes the consultant's modelling report and summary findings.

As in previous years, there have been high levels of engagement with industry participants and comprehensive public consultation in developing the 2012 GMR—with the aim of capturing all relevant views in a transparent manner and developing industry consensus on the outcomes. The GMR could not be undertaken without your ongoing contribution to the consideration of issues surrounding the Queensland gas market.

All feedback—comments, corrections and criticisms—are welcome as we continue to improve GMR market modelling and analysis.

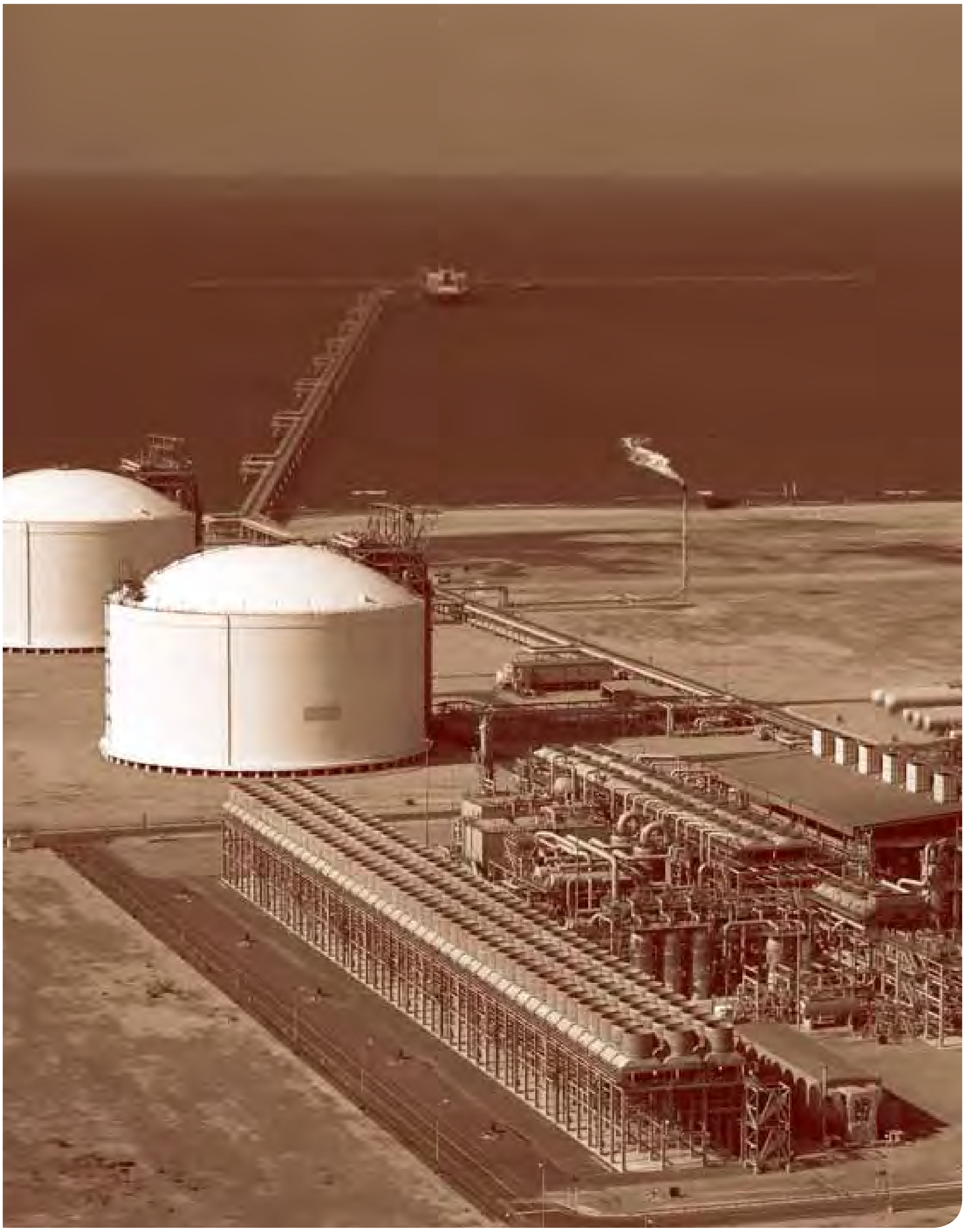
K F Gardiner

Kay Gardiner
Queensland Gas Market Advisor

Acknowledgments

The Queensland annual GMR is entirely dependent on the active engagement and contributions of gas market participants. I gratefully acknowledge the many organisations within the gas industry that voluntarily and enthusiastically participated in the review process and supplied information and views to help shape the preparation of the 2012 GMR.

Consultation and feedback are very important parts of the review process and I would like to thank all those who took the time and made the effort to respond to the consultation opportunities.



BG Group's Ikdu plant in Egypt

Source: BG Group

Summary

The annual GMR informs government decision-making regarding the need to develop PGPLR tenure. It also considers the development of a more competitive and transparent Queensland gas market, identifies constraints on gas supply availability and gas market development, and considers security of supply within the relative context in the broader eastern Australian gas market.

The Queensland Gas Market Advisor is responsible for leading the GMR process and advising the government on review outcomes. The Queensland Gas Market Advisor is also accountable for progressing government actions in response to the reviews.

The 2012 GMR has a strong upstream focus aimed at establishing reserves allocations and development rates, and identifying and quantifying any constraints on reserves that may impact on gas supply availability, gas market development, security of supply, and likely wholesale gas price outcomes in Queensland and in the broader eastern Australian gas market.

Background

Gas exploration and production in Queensland has a cyclical development pattern, with the state undergoing a lengthy period of incremental development interspersed with periods of major investment, projects and growth.

Since 2008, Queensland has experienced unprecedented growth with the development of the coal seam gas (CSG) to liquefied natural gas (LNG) export industry.

The overwhelming majority of Australia's current 2P reserves are found in Queensland—more than 93 per cent.

Modelling and analysis

The GMR is underpinned by gas market modelling and analysis. For the 2012 GMR, Intelligent Energy Systems (IES) was engaged in conjunction with Resource Land Management Services (RLMS) and Jenkins Advisory Services to model a 20-year study period.

It was a requirement of the modelling that, to the extent possible and reasonable, there was to be consistency with Australian Energy Market Operator (AEMO) Gas Statement of Opportunities (GSOO) scenarios and the economic scenarios used in the 2011 GMR.

This ensures stakeholders can make valid comparisons between the outcomes of the 2011 and 2012 GMR and the GSOO. Where there are reasonable differences, these are identified.

To address the influence of economic conditions and technical/operational issues, scenarios were developed to incorporate three key drivers that influence gas availability and price:

- macro-economic conditions
- LNG developments
- CSG developments.

Three modelling scenarios were developed for each driver. From these 27 combinations, 12 scenarios were identified for modelling.

The development rate for gas reserves is critical in assessing future availability of gas to meet domestic and export demand. The expected and potential development variation was assessed with allowances given to the variation in declared 2P reserves growth and forward projection.

This was undertaken using a consideration of conversion efficiency and conversion rate. Factors that influence conversion efficiency and conversion rate are well productivity and drilling rates (that impact the rate at which wells are developed).

Three scenarios of reserves development were used that correspond to an annual 2P increase in the range of about 3500 to 9500 PJ with an expected increase of about 5000 PJ. Also modelled were options to the operating rules for three 'modes'. These were the cooperation between the LNG proponents and the inclusion of prospective reserves.

A reference case was used to model potential gas reserves outcomes. It represents the most likely and realistic representation of how the market would develop:

- *medium* growth outlook
- *medium* LNG train development
- *planned* reserve development (medium reserve conversion efficiency and conversion rate)
- *base mode* (prospective resources included, LNG proponents not cooperating with each other).

The LNG development program is possibly the most important input for the Queensland gas market. Two future demand growth scenarios (labelled 'low' and 'high') of LNG development were developed by IES—a low demand scenario (approximately 4 per cent per annum growth) and a high demand scenario (approximately 6.5 per cent per annum growth).

Gas demand

The eastern Australian gas market is, in reality, a series of interconnected markets. Queensland, more so than any other eastern Australian state, also has a series of submarkets with different characteristics that are captured in the modelling. Queensland has a gas consumption of around 240 PJ per year and the eastern Australia gas market consumption is around 718 PJ per year.

LNG is the dominant force in the Queensland gas market moving forward, as seen in Figure 1 below. Figure 1 shows Queensland's gas demand and projected gas demand for LNG export. It assumes domestic demand is static at 2011–12 levels, with 6 LNG trains by 2015–16 and a further 2 trains by 2020–21.

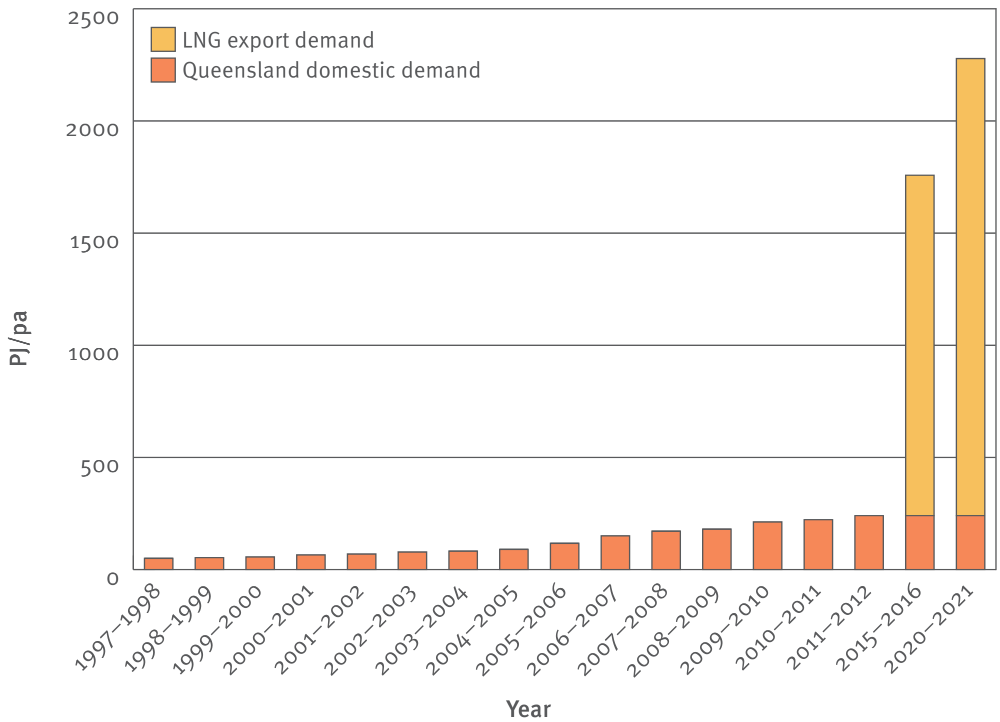


Figure 1 Queensland domestic gas demand and projected gas demand for LNG exports

The large industrial customers in Queensland comprise over 70 per cent of Queensland gas demand (excluding gas power generation (GPG) and LNG exports). Higher exchange rates and assessed gas costs result in the high scenario having lower large industrial demand in Queensland and the low scenario having higher demand (Figure 2 overleaf). In the high scenario, there was a relatively small increase in gas use in the other states.

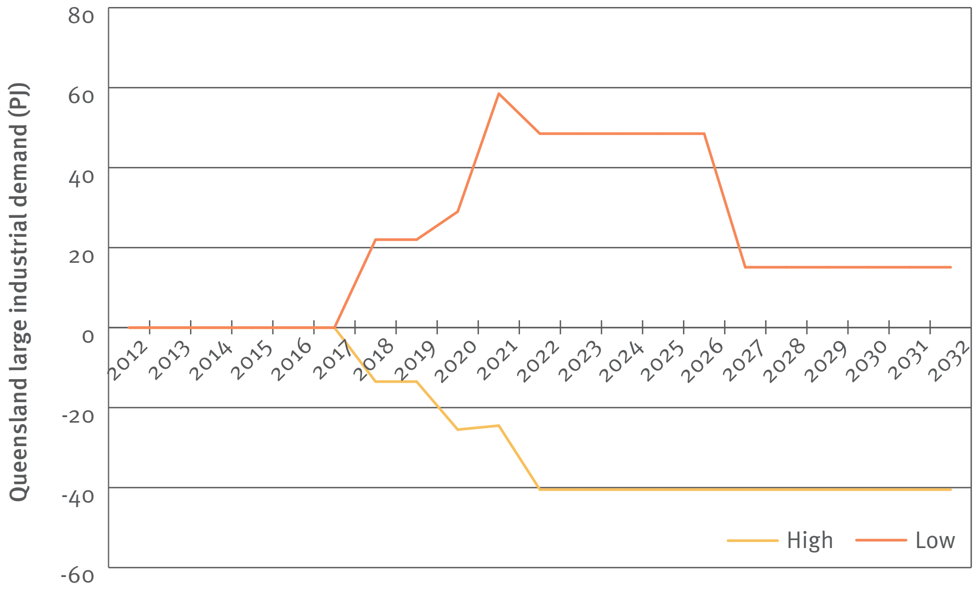


Figure 2 Queensland large industrial demand changes from the medium scenario (PJ)

Source: IES (2012)

GPG was envisaged to play an increasing role in the generation of electricity due to the lower carbon emissions of gas generation compared with coal generation. However, the economic modelling showed that the level of GPG did not change significantly between scenarios to 2020, and the increase in the level of GPG over the period to 2020 is small under all scenarios. Post-2020, GPG increases significantly with the level of increase being scenario-sensitive.

Gas pricing

The modelled price outcomes for the domestic market show that a high demand LNG development outlook, accompanied by high projected oil prices, would likely lead to domestic gas prices increasing to over $10/GJ by 2015 and gas scarcity for domestic contracts; whereas a modest oil and LNG development outlook could see prices in the order of $6.50/GJ by 2015. Under the same scenarios, gas prices in 2020 would be in the range (high to low) of $12/GJ to $7/GJ.

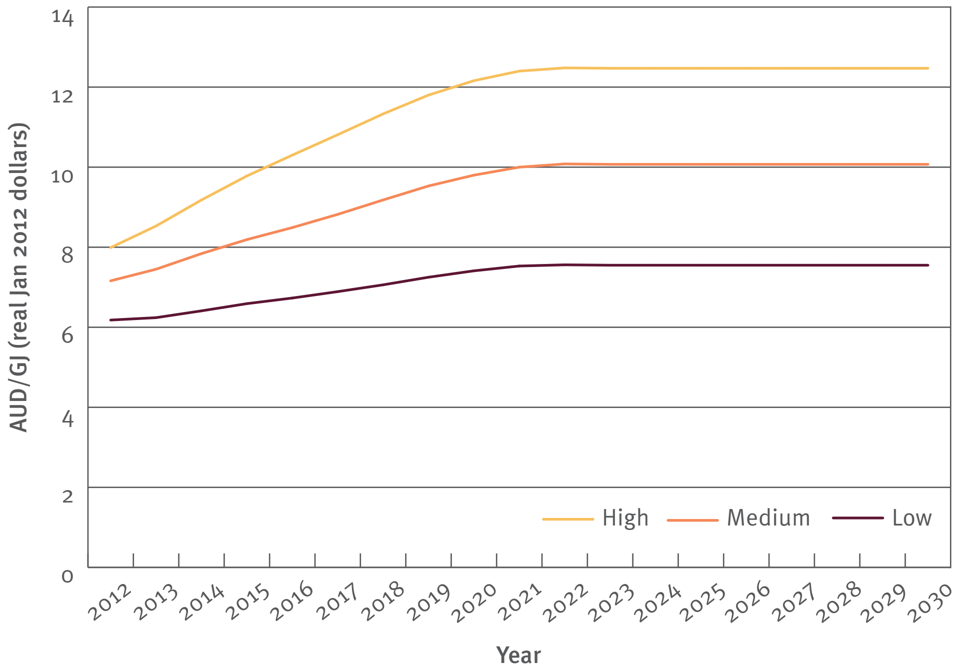


Figure 3 Range of Queensland long-term ex-field gas contract price outcomes ($/GJ)

Source: IES (2012)

Variations can be seen when prices are considered for the Queensland submarkets. Some of this variation can be attributed to the different production cost of gas from different fields that supply these markets and to the different distances gas must be transported from the fields to the submarkets.

The modelling indicates that, with the exception of Brisbane, the submarket variation in prices will decrease over time and prices will converge. The modelling also shows a widening gap over time between Queensland gas prices and those in southern states. If this price variation bridges the difference in Queensland CSG and southern conventional gas production costs, it could underpin the flow of southern states' gas to Queensland.

Gas reserves

Long-term contracts for gas supply are struck using 2P reserves estimates and these are the most widely quoted. In general, 2P reserves equal to the total contract gas quantity are required, although the producer may undertake to prove up sufficient reserves within a set period or on an annual basis, or agree to maintain a minimum number of years of reserves coverage at all times.

The concentration of the ownership of the largest volume of gas reserves is shown in Figure 4 overleaf, where companies holding less than 1000 PJ of 2P reserves are grouped together.

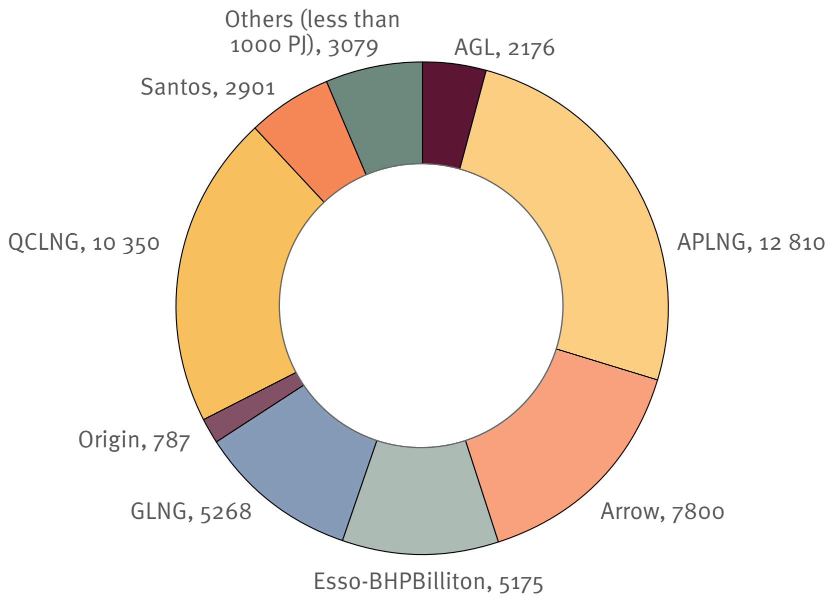


Figure 4 2P potential CSG reserves by CSG company

Source: Data sourced from IES/RLMS (2012)

Based on the range of 2P reserves development of 3500 to 9500 PJ with an expected increase of about 5000 PJ, the potential development rate of 2P reserves in Queensland is shown in Figure 5. Also shown are the total reserves required for 6 and 14 LNG trains (notionally of 4 million tonnes per annum (MTPA) capacity each and not related to the individual positions of the 4 proponents or geographic locations).

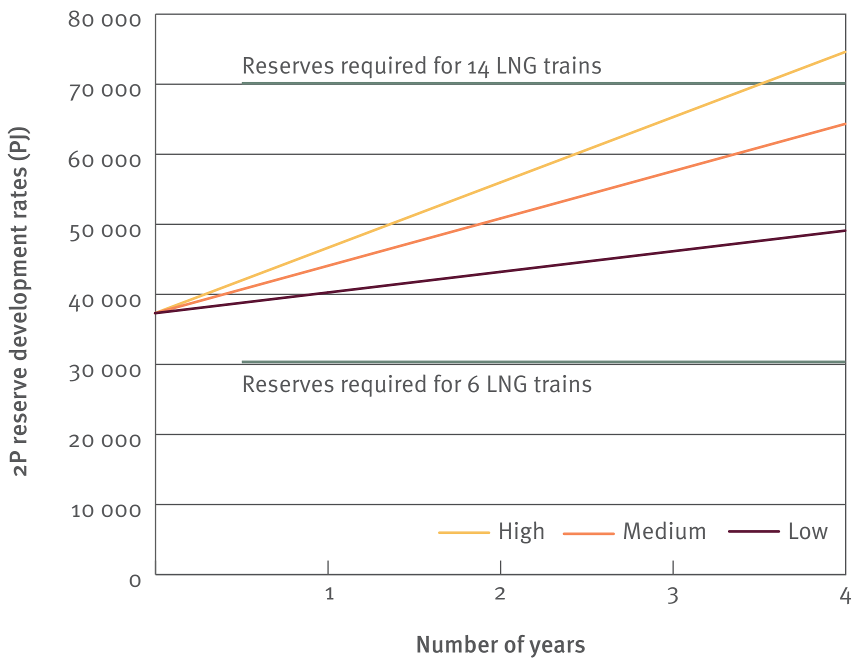


Figure 5 2P reserves development rates

Source: IES (2012)

When the reference case is modelled, there are currently just over 2000 PJ of non-LNG 2P reserves in Queensland and the Cooper Basin. This reduces over time to a low point around 2020 to 2022, primarily due to acquisition by LNG proponents who require more reserves for their LNG trains. Reserves required to be withheld for LNG development peaks around 2021.

All four LNG proponents are modelled to experience a shortfall in their required gas reserves for their LNG plant at some stage during the study period and are expected to be acquiring available reserves located in Queensland and the Cooper Basin from non-LNG businesses. No gas supply shortfalls occur during the study period modelling; but this is dependent on the time and efficiency rates of conversion of reserves to 2P and, further, of 2P reserves to produced gas. It also assumes that LNG proponents would make their surplus gas reserves available to non-LNG gas users.

In summary, with LNG developments limited to 8 trains by 2020 and an additional 4 trains by 2030, there are sufficient reserves to provide gas for the domestic market and any operational LNG trains over the study period. The results indicate that with the assumed LNG train development scenario, the gas market is expected to tighten further to 2021 before unconventional gas located in the Cooper Basin becomes available.

Over the next 2 to 4 years leading up to the commissioning of the 6 committed LNG trains, the reserve holding of the LNG proponents would have option value in maintaining opportunities for forthcoming decisions regarding additional LNG trains. This may lead to reluctance in making these available to the domestic market until such time as the option is deemed not viable. Domestic supply may be seen as more desirable and/or feasible in the event of a relatively pessimistic LNG outlook.

Gas supply

In the medium growth/medium LNG scenario, Queensland CSG dominates future supply from the commencement of LNG export in the period 2014 to 2015. The modelling suggests that by the middle of the next decade, Victorian conventional gas supply will increase and there will be modest but increasing supply from New South Wales CSG.

When the high growth/high LNG scenario is compared with the medium growth/medium LNG scenario, the increase in gas supply required to meet the higher demand comes from Queensland CSG. When comparing the low growth/low LNG scenario with the medium growth/medium LNG scenario, there is a decrease in supply from all sources, with the exception of Cooper Basin conventional gas.

Potential supply from the southern states to support future Queensland demand was modelled. This showed that, using the cost of supply plus pipeline costs, the economic outcome was Queensland gas demand supplied by gas fields in Queensland and that physical transport of gas from Victoria was not likely to be economic.

Physical constraints and the cost of transport are significant hurdles to wholesale sales of Victorian gas in Queensland. Only if supply costs in Victoria are substantially cheaper than Queensland CSG, or if the gas price in Queensland is substantially higher than the southern states, would gas transfers be considered likely. On this basis, significant gas swaps over longer timeframes would require a price differential settlement, but some small gas swaps could potentially proceed on a net transfer basis.

Market conditions issues and recommendations

Market conditions

- The Queensland gas market lacks liquidity, with gas in short supply for new contracts both pre- and post-2015.
- This is contributing to a high level of uncertainty in the market, which is also impacted by the uncertainties of domestic and international LNG and future gas prices.
- Ramp-up gas, that previous modelling assumed would be a feature of the market prior to the commencement of LNG export, has not materialised due to a range of management techniques including gas swaps between LNG proponents, and storage and production delays resulting from floods.
- In the 12 months to June 2012, customers seeking new domestic supply contract for gas post-2015 reported a continued lack of access to basic market information (forward prices, volumes available and potential delivery timeframes) for forward contracting. No customers seeking domestic supply of gas reported achieving a term sheet (binding or non-binding) for a large volume of gas. A small number of customers report offers of small volumes of gas for short-term supply.
- A feature of market activity in the past 12 months has been the entrance of LNG proponents as customers of other producers. In contrast to customers seeking domestic supply of gas, LNG proponents have been able to access the required information and contract for gas.

Market issues

- Access to gas reserves for domestic contracting is particularly sensitive to the development of new LNG trains prior to 2020, and this sensitivity could continue if a significant number of trains continued to be developed post 2020:
  - For the current level of 6 committed LNG trains and a further 2 trains post-2020 (8 in total), the modelling of gas reserves and ownership found that there were available reserves throughout the 20-year study period and sufficient gas to supply all demand including LNG trains. Under this scenario, gas would be expected to become available to the domestic market.
  - For the current level of 6 committed LNG trains and the construction of a further 2 trains prior to 2020 (8 in total), reserve levels available for domestic market contracting would be highly sensitive to, and dependent upon, planned or above planned reserves conversion and development rates. Low reserves conversion rates and slow development could result in a continuation of the current tight market conditions or, in the worse case, a potential reserves shortfall.
  - Beyond the development of 8 LNG trains prior to 2020 (6 currently committed, plus 2 additional), reserves shortfalls would occur with the level of shortfall proportional to the number of additional trains developed.
- Modelled gas prices fell in a wide range—$6 to $12/GJ depending on the submarket demand and oil prices. Similar to the 2011 GMR outcomes, regardless of demand, market expectation of future gas prices continues to remain at the higher end of the range.
- Implementation of the PGPLR cannot be supported based on current LNG projects that have reached final investment decisions (FID). However, even when these developments reach production capacity and gas reserves might be assumed to be available in the future to the domestic market, there is the potential for stockpiling of reserves to retain the option of developing further LNG trains. The pace of development of LNG trains, in addition to the 6 under construction plus a further 2 trains, will be a key issue impacting whether future domestic gas market liquidity improves or declines further.

Recommendation

The Queensland Gas Market Advisor recommends that government consider the security of domestic gas supply and market liquidity in the planning and approval process for development of future new LNG trains.

- Major industrial customers in the domestic market are effectively unable to resolve future contracting requirements and business plans due to lack of access to future gas supply contracting information—in market terms, the market is unable to 'clear'.
- Balance has not been achieved between large gas demand for export supply and demand for domestic gas supply.
- Industry debate on the issue appears to have become captured by the option to reserve gas for domestic use (reservation) and the price impact for domestic gas customers as result of connection to the international LNG market.
- There are a range of potential options, ranging from regulatory intervention to market facilitation, that could encourage market participants to achieve balanced export/domestic market outcomes, and a wider, more informed debate is desirable.

The Gas Market Advisor cautions that if the next 12 months does not see the future domestic supply situation improve, there could be insufficient time for development, consideration, consultation and implementation of measures that could be implemented by government to address a domestic supply constraint in the period 2015 to 2020.

Recommendation

The Queensland Gas Market Advisor recommends that government undertake early work to develop and consider measures that could be implemented in a timely manner should the future domestic supply constraint continue.

Schematic of Queensland Curtis LNG (QCLNG) plant near Gladstone

Source: BG Group

Introduction

The annual GMR informs government decision-making regarding the need to develop PGPLR tenure. It also:

- identifies and analyses key issues affecting the effective management of resources
- considers the development of a more competitive and transparent Queensland gas market
- helps stakeholders and government stay abreast of the increasing complexities of the Queensland market gas and its links to interstate and international markets
- identifies constraints on gas supply availability and gas market development
- considers security of supply within the relative context in the broader eastern Australian gas market.

The Queensland Gas Market Advisor is responsible for leading the GMR process and advising government on review outcomes. The Queensland Gas Market Advisor is also accountable for progressing government actions in response to the reviews.

Focus of the 2012 GMR

Gas is currently being supplied in the Queensland gas market and it is acknowledged that gas producers are attempting to prove up 2P gas reserves as quickly as possible. The 2011 GMR identified that access to gas reserves for contracting for the period 2011 to 2015, for gas supply in the period 2015 to 2020, was critical for security of future domestic gas supply.

In order to understand the potential speed of reserves growth, and therefore the level of reserves that might be available for contracting, we must understand the efficiency rate of development and the conversion rate of resources to reserves. Also critical to understanding the extent to which reserves will be available for domestic contracting is the allocation of reserves to LNG supply and the timeframe in which this occurs.

For this reason, the 2012 GMR has a strong upstream focus aimed at establishing reserves allocations, development rates and identifying and quantifying any constraints on reserves that may impact on gas supply availability, gas market development, security of supply, and likely wholesale gas price outcomes in Queensland and in the broader eastern Australian gas market.

The GMR considers and models issues, including:

- gas reserves, including relevant matters such as resource to reserves conversion rates, reserves and potential reserves locations relative to current and future demand centres, necessary infrastructure connections and any facilities required for development
- wellhead (ex-field) gas costs/prices
- identification from a Queensland perspective of any barriers to growth of the eastern Australian gas market as a whole and/or, any Queensland market segment
- customer demand for all market demand segments (wholesale and retail) and drivers for demand growth
- any significant differences in outcomes from previous GMR modelling or other significant industry gas market modelling
- the timing and level of any identified future gas supply/demand/reserves imbalances.

The 2012 GMR continues to focus on the modelling horizons to identify major potential demand growth or supply shortfalls, including the immediate years 2015 to 2017 when LNG exports are scheduled to start. This timeframe is important as it reflects the period within which reserves must be developed and available for delivery for LNG contracts commencing in 2015, and for new domestic customer contracts to satisfy demand in the period 2015 to 2020.

Consultation for the 2012 GMR

A primary objective of the Queensland Gas Market Advisor is to provide an independent, single point of contact for ongoing dialogue between government and industry stakeholders on gas market issues. The annual GMR is a valuable and focused part of this dialogue.

A transparent review process, high levels of engagement and thorough consultation are necessary to ascertain and distil the wide range of views, information and issues impacting the gas industry in 2012, together with issues likely to impact the future of the gas market.

In undertaking the 2012 GMR:

- the Stakeholder Reference Group was utilised
- two stakeholder forums were held
- draft modelling and analysis work was released for consultation through the Stakeholder Reference Group
- the Queensland Gas Market Advisor engaged in 31 one-on-one meetings with stakeholders
- the draft 2012 GMR was released for public consultation.

Consultation meeting discussions with stakeholders focused primarily on:

- stakeholder project development (demand-side and supply-side)
- issues regarding domestic demand and supply, including counterparties' willingness to buy or sell gas
- changes over the 12 months since the previous GMR.

Consultation has provided an excellent understanding of issues faced by stakeholders and of current gas market conditions. All information provided during consultation was in confidence and has not been reproduced in this report unless independently sourced from public reports.

Issues and concerns raised by stakeholders have been captured in the relevant sections of this report and, where appropriate and practical, considered as part of the development, modelling and analysis for the 2012 GMR.

Prospective gas production land reserve

The PGPLR policy aims to ensure the future security of supply for domestic gas users in light of the international demand for gas. The ability to enact the PGPLR is provided in legislation and can be actioned by government, where supported by outcomes of the annual GMR process, if domestic market supply becomes constrained or is forecast to become constrained.

The PGPLR provides the ability to condition tenure and grant such that any gas produced from sale from the area can only be consumed within the Australian gas market.

Background

Gas exploration and production in Queensland has a cyclical development pattern, with the state undergoing a lengthy period of incremental development interspersed with periods of major investment, projects and growth. Since 2008, Queensland has had unprecedented growth in the development of the CSG to LNG export industry.

Gas is frequently categorised as 'conventional' or 'unconventional' with regards to exploration or production. Conventional gas is found in sandstone and carbonate reservoirs with good porosity and permeability, and is usually discovered in the same types of reservoirs as oil. Conventional gas discoveries are associated with oil exploration. Conventional gas is produced in south-western Queensland at Ballera and in smaller volumes around Roma and Rolleston.

Unconventional gas is tight gas, shale gas or CSG:

- **Tight gas** is gas held tightly in low permeability conventional gas reservoirs. Prospective tight gas areas are known to be located around Ballera, but the cost to extract is not currently clear.
- **Shale gas** refers to significant accumulations of gas trapped within shale formations called 'plays'. Shale is a fine-grained sedimentary rock that forms from the compaction of silt and clay-size mineral particles (mud). It is the most commonly found sedimentary rock worldwide. Shale gas is produced by drilling horizontally along the play. Prospective areas of shale gas are known to be located around Ballera and Maryborough, but no reserves have been declared. The extent, ability to extract and cost are currently not clear.
- **CSG** is attached to coal along its natural fractures and cleats. CSG is released when pressure in the coal seam is reduced, usually by removal of water from the seam. CSG is produced by drilling a well into a coal seam. Gas is then released by pumping water from the seam to reduce water pressure.

Gas in Queensland

The overwhelming majority of Australia's current 2P reserves are found in Queensland—more than 93 per cent.

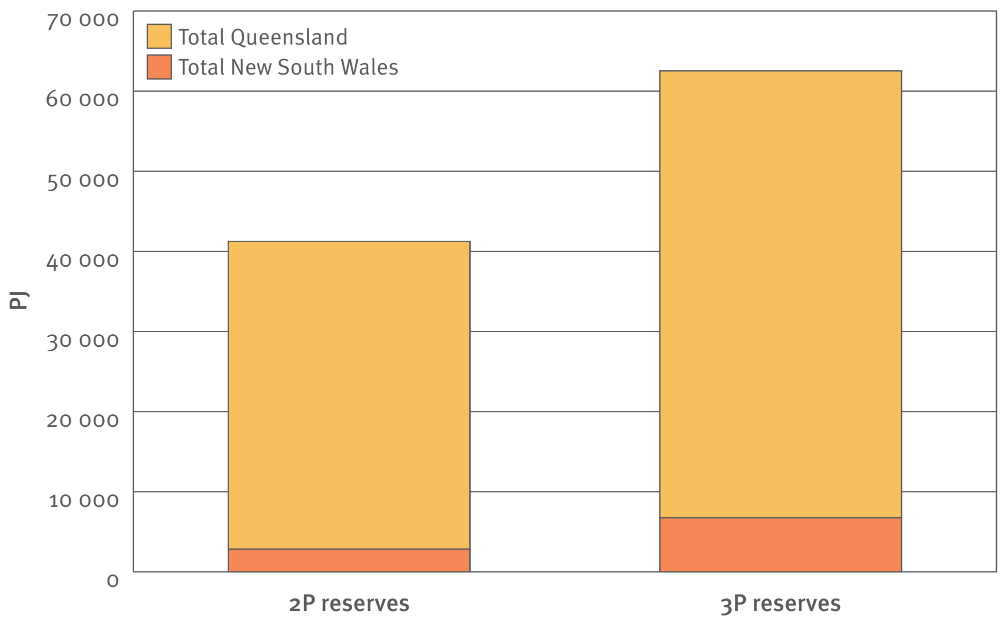


Figure 6 Eastern Australian CSG reserves by state (31 December 2011)

Gas

The Queensland annual GMR deals exclusively with natural gas—referred to simply as 'gas'.

Gas is a blend of hydrocarbons (primarily methane and inert gases) found in sandstone, carbonate and shale reservoirs, and in coal seams at depth in the earth's crust.

Gas suppliers

Gas is currently supplied to the Queensland market by the following participants:

- **AGL Energy** – AGL currently supplies around 29 per cent of the eastern Australian domestic market as well as having significant gas-fired power generation holdings. AGL's major reserves in Queensland are around the Moranbah area, where it supplies a net 24 TJ/d to Townsville.
- **Mitsui E&P/WestSide Corporation/Molopo Energy** – These three companies currently supply small quantities of gas in Queensland (around 1.5 per cent of the market). WestSide Corporation and Molopo Energy operate adjacent tenements in the Dawson Valley near Moura, with Mitsui E&P having interest in both tenements.
- **Origin Energy (Origin)** – Origin is a major supplier of gas in Queensland and a major shareholder of the APLNG project (42.5 per cent). Origin holds a portfolio of gas reserves that includes a small portfolio of conventional gas reserves in the Surat Basin and the recently announced Ironbark CSG project, which is expected to supply a total of 1600 PJ over 40 years from 2014. Origin also has conventional gas reserves in the Cooper–Eromanga Basin and significant conventional gas reserves and resources in the Bass and Otway Basins off the Victorian coast.
- **Australia Pacific LNG (APLNG)** – APLNG is the most significant CSG supplier to domestic consumers, including Origin's power generation requirements. Virtually all the gas sales agreements (GSA) that Origin entered into before the finalisation of APLNG are supplied by reserves that now belong to APLNG.
- **Santos** – Santos is the project leader for the Gladstone LNG (GLNG) project that does not yet have sufficient certified 2P gas reserves for a full 20-year, 2-train operation. Santos has significant gas reserves and resources in eastern Australia outside of GLNG. These are held in the Cooper, Gunnedah and Otway Basins. Santos also has significant uncontracted CSG reserves and resources in the Surat and Gunnedah Basins.
- **Arrow Energy (Arrow)** – While Arrow does not have sufficient 2P reserves at this time to support a 2-train export LNG plant for a full 20 years, it purchased Bow Energy in early 2012 and holds a number of permits in the Bowen Basin as well as having interests in the Surat and Cooper–Eromanga Basins. Arrow holds a number of existing contracts with major customers.
- **QGC** – QGC's current primary production and tenures under development are in the Surat Basin, but it also holds tenure in the Bowen Basin. QGC currently supplies gas to a number of existing Queensland customers, but is understood to be focusing on developing its reserves towards its LNG project. Future gas availability to the domestic market will depend on its reserve position and LNG export expectations.

Several smaller companies that hold reserves in Queensland and northern New South Wales are unlikely to be in a position to supply the domestic market for at least the next 5 years.

Gas transmission pipelines

Gas transmission refers to the transportation of natural gas via pipelines from gas production facilities to major users and markets.

The major east coast Australian gas transmission pipelines, their regulatory status, average capacity factor and capacity (forward/reverse) are shown overleaf. Not all pipelines serve demand centres. Some provide transmission capacity between two other pipelines, such as the South West Queensland Pipeline.

Table 1 Regulatory classification and capacity of major transmission pipelines

Name	Regulation	Average capacity factor (%) *	Capacity TJ/day
North Queensland Gas Pipeline (NQGP)	None		108
Queensland Gas Pipeline (QGP)	None	79	142
Carpentaria Gas Pipeline (CGP)	Light	81	119
Roma to Brisbane Pipeline (RBP)	Full	75	219
QSN Link Pipeline (QSN)	None	83	385
Moomba to Sydney Pipeline (MSP)	Light	41	439
Moomba to Adelaide Pipeline (MAP)	None	50	253
SEA Gas Pipeline	None	50	314
Eastern Gas Pipeline	None	80	268
NSW–Victoria Interconnector	Full	23	90/73
South West Queensland Pipeline (SWQP)	None	34	353/129
Longford to Melbourne	Full	48	1030
Tasmania Gas Pipeline	None	35	129

**Source: IES (2012)—calculations based on information sourced from the Gas Bulletin board*

Existing major gas pipelines

Existing and proposed new pipelines are shown in Figure 7 overleaf. The four major interconnected natural gas transmission pipelines in Queensland are the:

- RBP – running from Wallumbilla (Roma) to Gibson Island in Brisbane and owned and operated by the APA Group (APA)
- CGP – running from Ballera to Mount Isa Pipeline and owned and operated by the APA
- QGP – running from Wallumbilla to Gladstone and Rockhampton, and owned and operated by Jemena Limited
- SWQP – connecting Ballera and Wallumbilla, and is owned and operated by Epic Energy.

The QSN Link interconnects the SWQP with the MSP and MAP.

The initial capacity of the RBP, QGP and CGP has been expanded, with more expansions either underway or planned to meet domestic market demand.

Another major pipeline, the NQGP, runs from Moranbah to Townsville. It is owned by Victorian Funds Management Corporation and operated by AGL and Arrow Energy through a jointly owned company called NQPM4.

Proposed new transmission pipelines

Each of the LNG proponent groups have designed their projects around dedicated gas transmission pipelines linking the upstream gas production centres with the LNG processing plants on Curtis Island. Four new Queensland transmission pipelines are planned to supply gas from the Surat Basin to Gladstone for LNG processing:

- **Queensland Curtis LNG (QCLNG)** – The QGC-managed QCLNG project has commenced the preliminary construction activities for a 380 km, 1050 mm pipeline. This pipeline will start near Miles and be fed by treated gas from the project's Surat Basin Gas Fields via two major gas headers of some 150 km in length.
- **GLNG** – The GLNG project has commenced early construction activities on a 420 km, 1050 mm pipeline to operate up to 10.2 MPa. This pipeline will follow the basic alignment of the QGP from Arcadia to Callide, where it will use the Queensland Government's major infrastructure corridor (also being used by the other LNG proponents), which goes all the way to Gladstone.

- **APLNG** – The APLNG pipeline alignment roughly parallels that of QCLNG from Miles to Callide, before traversing to Gladstone by way of the common infrastructure corridor. The major part of the pipeline is 380 km of 1050 mm section pipe with maximum operating pressure of 10.2 MPa. Gas will be fed into this pipeline from 70 km of large-diameter headers. APLNG have commenced preliminary construction activities on their gas transmission pipeline.
- **Arrow LNG** – The Arrow Surat Pipeline has a planned length of 470 km, including major headers and transport. It will be aligned east of the QCLNG and APLNG pipelines until it joins the common infrastructure corridor at Callide.

Proposed multi-user pipelines

A number of new multi-user gas transmission pipelines are undergoing detailed feasibility studies:

- **Arrow Bowen Gas Pipeline** – The Arrow Bowen Gas Pipeline would connect Arrow's gas operations in the Bowen Basin to a Gladstone LNG plant. The pipeline is proposed to commence approximately 90 km north of Moranbah with the route to Gladstone mostly east of the Bowen Basin Coal Measures. It will have an approximate length of 477 km with three major laterals of some 103 km.
- **Queensland Hunter Gas Pipeline** – The Queensland Hunter Gas Pipeline is a proposed 850 km gas pipeline running from Wallumbilla to Tomago near Newcastle through the Gunnedah Basin. The pipeline has received environmental and regulatory approvals from both the Queensland and New South Wales governments, and is now being considered in two stages—the first stage being from Narrabri to Wallumbilla and the second stage from Narrabri to Newcastle.
- **Lion's Way Gas Pipeline** – Metgasco proposes to connect its gas reserve and resource base in the Clarence–Moreton Basin in northern New South Wales to the RBP near Ipswich, via construction of a 145 km pipeline from near Casino. It would follow the alignment of the Lions Way—a road and rail corridor through the Border Ranges between New South Wales and Queensland.
- **Galilee Basin Gas Pipeline Studies** – While the Galilee Basin is in its early stages of exploration activity, a number of the permit holders exploring in the basin have undertaken preliminary studies into how any gas production from their tenements might get to market. All of these studies are preliminary scoping exercises based on individual company expectations. It is too early to undertake such an investigation in a meaningful way until the gas resource across the basin is better understood.

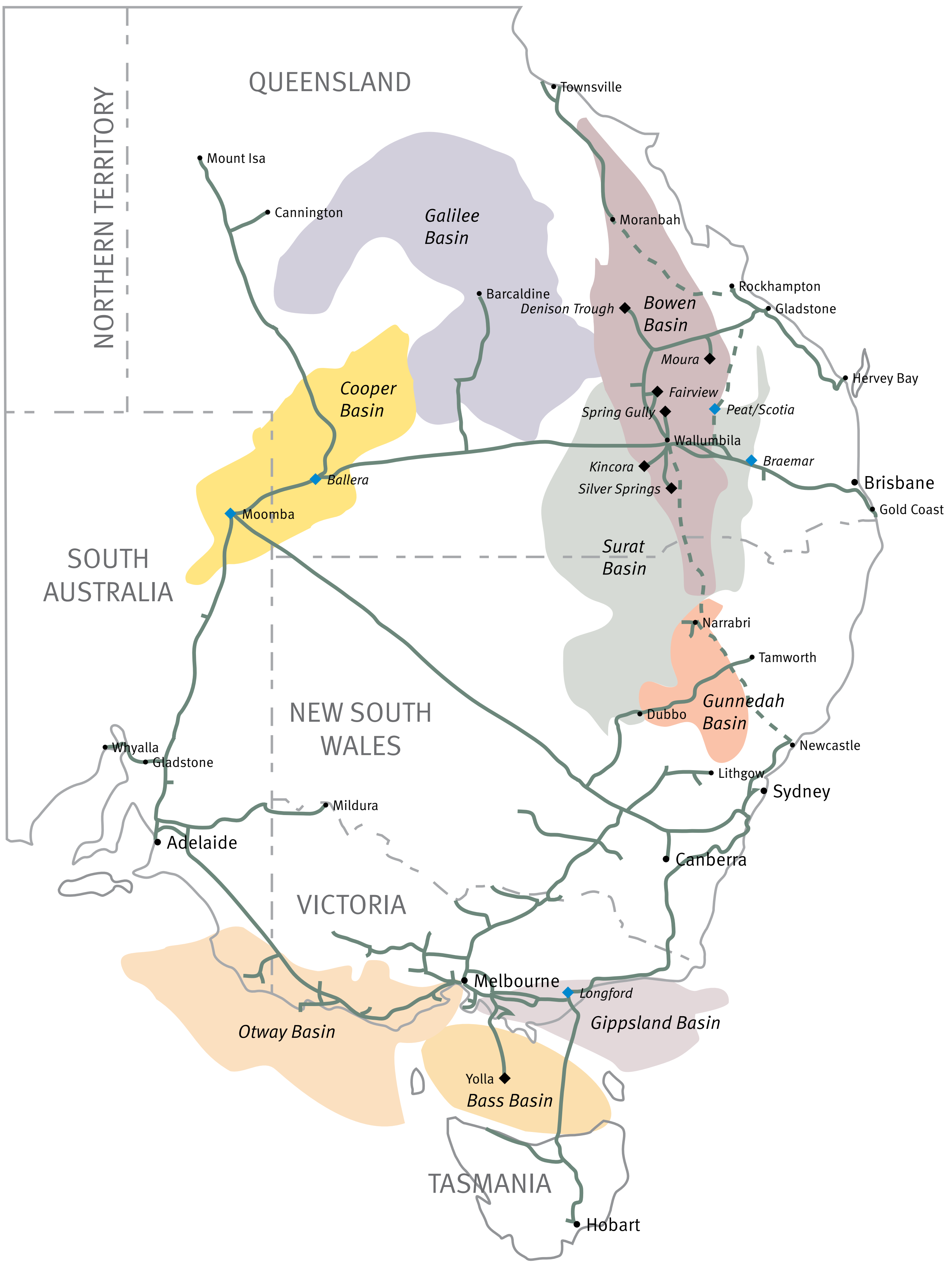


Figure 7 Eastern Australian gas basins and pipeline network

Source: Data sourced from IES/RLMS (2012)

Gas distribution networks

Gas distribution refers to the delivery of natural gas via distribution pipeline networks (serviced by transmission pipelines)—natural gas distribution networks in Queensland are operated by APA. In Brisbane, the network covers the Gold Coast and southern and northern Brisbane. Small distribution networks are also located in the regional areas of Toowoomba, Oakey, Bundaberg, Maryborough and Hervey Bay. Roma and Dalby are serviced by networks owned and operated by their local councils.

Gas distribution networks in Queensland continue to increase overall customer connection numbers; but overall gas use is declining, reflecting the impact of competition from other fuel sources and improved appliance and operational efficiencies. Gas consumption of the Queensland distribution networks is approximately 29.5 PJ per annum consumed by approximately 172 000 customers. Around 96 per cent of these customers are residential users consuming approximately 1.6 PJ per annum or 5 per cent of total consumption.

Average residential consumption in Queensland is currently about 9 to 10 GJ per annum; down from the 11 to 12 GJ per annum of earlier years. The primary gas use underpinning residential load is gas hot-water heating, which faces strong competition from solar and heat pump appliances and improved water-use efficiency by south-east Queensland households. Lower water use means lower hot water use, and this is reflected in a reduction in gas consumption for water heating.

In the commercial and small industrial sector, volume is growing slowly but steadily at around 1 per cent per annum due to increasing business focus on efficient energy use. Customer numbers are expected to grow at less than 1 per cent per annum.

Retail market

The retail market for gas in Queensland is deregulated and based on the distribution networks. Maranoa Regional Council and Western Downs Regional Council operate small combined distribution and retail businesses, and there are five holders of general retail authorities to retail gas in Queensland:

- AGL
- Origin Energy
- Australian Power & Gas (AP&G)
- Dodo Power & Gas
- EnergyAustralia.

AGL, Origin Energy and AP&G are active in the Queensland retail market. AP&G services a small number of customers. While there is no impediment to customers changing retailers, there currently appears to be low levels of customer churn. There is potential for additional new entrant retailers and improved competition since the commencement of the Short Term Trading Market (STTM) in Brisbane on 1 December 2011. The STTM also offers larger retail customers the opportunity to purchase gas from the STTM as a further supply option and to address trade imbalances.

Eastern Australian gas market

The eastern Australian gas market—which consists of Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania—has a domestic gas demand estimated at 780 PJ per annum. The eastern Australian gas market operates with long-term GSAs between gas producers and buyers such as retailers, large industrial users and generators. Gas is delivered via equally long-term transmission agreements.

Although it will be 3 to 5 years before exports of LNG start from Queensland (based on current project schedules), the export projects have already changed the domestic demand-supply dynamic. The primary factors expected to influence the future direction of the gas industry in eastern Australia are LNG exports and gas reserves development.

LNG

Once gas is cooled to 161 °C at atmospheric pressure, it becomes a liquid that occupies less than 0.2 per cent of its original volume, making international transportation economical.

LNG production facilities are called 'trains'. Each train is an independent unit that converts (or liquefies) gas. Typically, trains produce 3 to 5 MTPA of LNG, equivalent to 165 to 275 PJ per annum.

The LNG market represents about 9 per cent of the global gas market and is the primary source of supply for countries with no domestic gas supplies, such as Japan, Korea and Taiwan. LNG is a supplementary supply in other countries, including many European countries, China and India. The international LNG import market has three broad regions—Asia, Europe and the Americas—with Asia being the region of growth.

LNG projects

The first CSG-based LNG project was announced in May 2007. Four projects currently have 'significant project' status and three have all the necessary approvals for project development.

Table 2 LNG project trains under construction/development

LNG project	Train capacity (MTPA)	Trains under construction	Project size (MTPA)	Gas use per train (PJ/a)	Scheduled start-up
Australia Pacific LNG (APLNG)	4 500 000	2	18 000 000	270	Q2-2015
Gladstone LNG (GLNG)	3 900 000	2	12 000 000	234	Q1-2015
Queensland Curtis LNG (QCLNG)	4 250 000	2	13 500 000	255	Q4-2014
Arrow LNG	4 000 000	0	16 000 000	260	Q1-2017*

**Project has not currently reached FID.*

Source: RLMS (2012)

Two projects—QCLNG and GLNG—have reached FID and are constructing 2 LNG trains. The project schedules suggest that QCLNG's trains will start up in 2014 and 2015, and that GLNG's trains will start up in 2015 and 2016. APLNG has reached FID for the project's first train and is expected to reach FID for the second train in the second half of 2012.

Arrow LNG is owned in a 50/50 joint venture by Royal Dutch Shell and China National Petroleum Corporation (PetroChina), and has released the project's environmental impact statement (EIS) for consultation.

More detailed information on the four major LNG projects is provided in Table 3 (overleaf).

Table 3 Queensland LNG major project structure and key proposed parameters

Project	No. of trains proposed (× MTPA)	Date project announced	Participants	Committed customers (HoA or MoU) (MTPA)	Significant project declaration	Environmental approval		FID	Train start-up schedule
						Queensland	Federal		
Queensland Curtis LNG (QCLNG)	3 × 4.25	1 Feb 2008	• Queensland Gas Company (wholly owned by BG Group) • Tokyo Gas • China National Offshore Corporation	CNOOC (3.6) Tokyo Gas (1.2) Singapore (up to 3) Chile (1.7) Chubu Electric (0.4)	4 Jul 2008	23 Jun 2010	22 Oct 2010	31 Oct 2010	2014 2015
Gladstone LNG (GLNG)	2 × 3.9 1 x 2.2	18 Jul 2007	• Santos • Petronas • Total • KOGAS	Petronas (3.5) KOGAS (3.5)	16 Jul 2007	28 May 2010	22 Oct 2010	13 Jan 2011	2015 2016
Australia Pacific LNG (APLNG)	4 × 4.5	8 Sep 2008	• Origin Energy • ConocoPhillips • Sinopec	Sinopec (4.3)	9 Apr 2009	8 Nov 2010	21 Feb 2011	28 July 2011 (1st train) (Expected 2012 for 2nd train)	2015 2016
Arrow LNG Project (Arrow LNG)	4 × 4	16 Feb 2009*	• Shell • PetroChina	PetroChina (n/a)	12 Jun 2009	Pending EIS	Pending EIS	Late 2013 (target)	2017/2018

**This is the original date of a Shell proposal for a 4 × 3–4 MTPA project on Curtis Island. The joint venture bid for Arrow was announced on 8 March 2010.*

Responses to issues raised in the 2011 GMR

In August 2011, the Queensland Government considered the 2011 GMR and accepted all the recommendations made.

Gas reserves

During consultation for the 2011 GMR, customers and potential customers advised of an almost universal inability to engage in meaningful, substantive negotiations with producers regarding domestic GSAs for supply in the period 2015 to 2020. The 2011 GMR concluded that:

- customer concerns regarding access to gas reserves for contracting in the period 2011 to 2015, for gas supply commencing in the period 2015 to 2020, were supported by the modelling and analysis undertaken for the 2011 GMR
- for efficient operation, the Queensland gas market required clarity on the activities underway to develop reserves for domestic market use post-2015
- unless domestic appraisal plans were in place or shortly to be put in place, available gas reserves may not be sufficient to underpin execution of new domestic GSAs.

It was recommended that the government seek detailed advice, confirmation and commitment from gas producers regarding drilling and appraisal programs to provide reserves for new domestic contracting in the period 2011 to 2015 for gas supply in the period 2015 to 2020. The government sought this information from six major gas producers/LNG proponents:

- AGL
- APLNG
- Arrow
- Origin
- QGC (part of the BG Group)
- Santos.

All six respondents firmly reiterated their commitment to being a long-term supplier to the domestic gas market. Information was provided by some proponents on tenures being developed for domestic supply, redevelopment of the Cooper Basin and further exploration of tight and shale gas resources.

Gas transmission pipelines

The initial capacity of the RBP, QGP, SWQP and CGP has been expanded, with more expansions either underway or planned. While these are being undertaken in a timely manner, pipeline owner-operators expressed a desire to allow a reasonable volume for further incremental growth when undertaking a major capacity expansion. Customers also sought this outcome. This issue was also noted by the Australian Government in its *Draft energy white paper 2011* released on 13 December 2011.

The 2011 GMR concluded that there appeared to be the potential for a category of customer to be excluded from timely purchase of pipeline capacity due to their volume requirements, and the issue would require a review of the relevant sections of the national legislation. It was recommended that the government act through the appropriate jurisdictional forum/s to raise the issue of incremental pipeline capacity expansion for review.

Development of the gas supply trading hub will require a concurrent consideration of gas pipeline capacity issues and the drivers for incremental investment in capacity. This issue is on the current Standing Council on Energy and Resources (SCER) work program.

Gas distribution networks

The 2011 GMR found that Queensland gas distribution networks face significant fuel competition, including from coal, which continues to be used as a fuel by some customers with access to gas. Coal use had dropped over the years, but it remained as a competitor and its use equated to several petajoules per year of gas use.

Little work had been done, but the 2011 GMR concluded that this area offered some potential to increase gas consumption on the distribution networks and improve utilisation of the infrastructure. It was recommended the government investigate the potential to increase gas consumption on the distribution networks and improve utilisation of network infrastructure by encouraging customers using coal as a fuel to move to gas, where gas is available.

The investigation is being undertaken by the Department of Energy and Water Supply.

Trading markets

Once the three committed Queensland CSG to LNG projects are fully operational after 2015–16, the annual volume of gas required by the projects will exceed 1500 PJ per annum. Total demand in Queensland will exceed 1700 PJ per annum—around 2.5 times the volume of gas currently consumed in the entire east coast gas market. The growth in gas production is centred in the Surat Basin region around Wallumbilla where three major gas transmission pipelines interconnect and four new pipelines are planned.

The 2011 GMR concluded this provides a timely opportunity in the period to 2015 to design, develop and implement a wholesale gas trading market at Wallumbilla. It was recommended that the government continue to work through the SCER and with other jurisdictions, the gas market reform process and stakeholders to settle a design for a supply-based trading market for implementation by 2015.

At its 9 December 2011 meeting, SCER noted the rapid changes in the Queensland gas market and identified the gas supply trading hub as a potential next step in the gas market reform process. SCER requested that the AEMO undertake rigorous consideration of whether pursuing a gas supply hub trading market had merit. AEMO worked with an industry reference group to develop a market design for consideration by SCER at the June 2012 meeting.

At the SCER 8 June 2012 meeting, Ministers noted the scoping and cost report prepared by AEMO and agreed to give further consideration to its implementation. Ministers agreed to task AEMO to prepare a report, in close consultation with industry participants, on the detailed design of a gas supply 'brokerage hub' trading market at Wallumbilla, Queensland. SCER also noted the importance of pipeline capacity trading in ensuring the success of the gas supply hub. Ministers have requested that the issue be considered further, in close consultation with stakeholders, as part of the broader SCER gas market development agenda. Ministers will consider this issue further in December 2012.

Gas storage

Produced and processed natural gas can be stored for an indefinite period. Storage of sales-quality gas is, like trading markets, a feature of mature gas markets and is widely used in North America and Europe to better manage variations in production capability and market and customer demand. The development of dedicated commercial natural gas storage facilities can provide flexibility for both producers and customers, support competitive market trading and enhance security of supply.

Under existing Queensland petroleum legislation, underground storage of petroleum can be undertaken under a petroleum lease. The legislation does not envisage gas storage outside of a current depleted petroleum area (e.g. the use of salt caverns) and does not seek to regulate the safe operation of such facilities.

The 2011 GMR concluded future investment in gas storage projects in Queensland will require appropriate tenure and tenure management, and the ability to effectively regulate the safe operation of storage facilities regardless of tenure type or location. It was recommended that the government consider a review of existing Queensland petroleum and minerals legislation to ensure a solid legislative foundation for future investment in, and operation of, dedicated gas storage facilities in Queensland.

The review is being undertaken by the Department of Natural Resources and Mines.

Modelling and analysis

The GMR is underpinned by gas market modelling and analysis. For the 2012 GMR, IES was engaged in conjunction with RLMS and Jenkins Advisory Services to undertake gas market analysis and modelling for a 20-year study period. The IES report on the modelling and analysis has been released with this 2012 GMR.

IES undertook economic modelling that addressed the economic fundaments and ignored participant reserve requirements, thereby providing insights such as the level of GPG and new pipeline developments. Next, modelling that tracked the reserve positions of the individual LNG proponents, their required reserve holding for their respective LNG trains and the reserves of non-LNG companies was undertaken. This modelling also considered the sensitivity of how cooperation between the LNG proponents would influence the market.

Other issues included in the modelling were:

- **gas demand**
  - timing of LNG plant commitment, construction, start-up and the consequent timing of gas reserves commitments in the context of global LNG demand
  - domestic gas demand projections, the requirement for new gas contracts to support demand growth and replacement of existing contracts and the gas reserves required
- **gas supply**
  - the rate of development of gas reserves (importantly CSG in Queensland) and factors that may affect it
  - factors and behaviours that may restrict production of gas from certain reserves, such as transmission connection to markets
- **demand–supply balance**
  - assessment of the physical ability of gas supply to meet projected gas demand
  - projected demand, supply and price outcomes for three economic scenarios.

Terms of reference/key inputs

It was a requirement for IES, to the extent possible and reasonable, to ensure consistency with AEMO GSOO scenarios and the economic scenarios used in the 2011 GMR. This ensures stakeholders can make valid comparisons between the outcomes of the 2011 and 2012 GMR and the GSOO. Where there are reasonable differences these are identified.

It was also a requirement that IES address the issues confronting the gas industry over the next 5 to 7 years. It should also address the longer term and additional scenarios that take into account technical and operational issues.

Key direct inputs and scenario variables for the modelling included:

- domestic gas demand and LNG export development in Queensland
- gas production costs
- gas reserves estimates, reserves conversion rates and production projections
- economic parameters, including economic growth and associated commodity prices, the price of carbon and international oil and gas prices
- electricity market demand.

Key components of the 2012 GMR are the scenarios that are to be subject to modelling.

The scenarios

The scenarios developed and the assumptions made by IES are explained below. Please refer to the IES modelling report for further detailed information on the scenarios and assumptions.

In order to address the influence of economic conditions and technical/operational issues, the scenarios were developed to incorporate three key dimensions that influence gas availability and price:

- **Macro-economic conditions** – This refers to the factors that influence costs, domestic demand, GPG development and economics of LNG export development. This includes factors such as carbon emission policy, global conditions, oil price etc. These were developed using the AEMO scenarios as a basis.
- **LNG developments** – This refers to the number of LNG trains developed in Queensland before 2020 and after 2020. While the economics of an LNG plant is being treated as an output of the modelling, this recognises that there is a potential range of developments within a set of macro-economic conditions.
- **CSG development factors** – This refers to the dynamics of CSG gas availability as influenced by (1) the development rate of reserves (conversion efficiency) compared with that planned and (2) the productivity of wells compared with that expected.

Three modelling scenarios were developed for each driver. From these 27 combinations, 12 scenarios were identified for modelling. The scenarios are intended to capture the potential spread of long-term economic outlooks as contained in the AEMO scenarios, as well as the influence LNG economic projections and reserves development can have in the medium term.

Economic scenarios

As a basis of the macro-economic scenarios for this study, IES developed three 'modified AEMO scenarios' as follows:

- **Modified AEMO scenario medium** – This is based on the planning scenario modified to account for factors such as lower growth than AEMO medium.
- **Modified AEMO scenario low** – This is based on the slow rate of change scenario. Particular change is a low price on carbon emissions.
- **Modified AEMO scenario high** – This is based on the decentralised world scenario modified, among other things, to have a slightly higher economic growth than the planning scenario.

The basis of the assumptions is as follows:

- domestic gas demand – 2011 GSOO modified through discussions with users and scenario assumptions
- electricity demand – 2011 Electricity Statement of Opportunities (ESOO) adjusted for current level and trend
- carbon price – consistency with AEMO scenario interpretation
- oil price – determined by the current price level and a conceivable view of the long-term price range
- exchange rate – consistent with the range and pattern presented in the ACIL report, *Fuel cost projections natural gas and coal outlooks for AEMO modelling*, dated December 2011.

Table 4 (overleaf) provides a summary of these assumptions. IES provide very detailed descriptions of the scenarios in Appendix G of the IES modelling report.

Table 4 Overview of key assumptions for economic scenarios

	High	Medium	Low
Economic growth			
Gas demand	GSOO modified	GSOO modified	GSOO modified
Electricity demand	Current moving to ESOO low	Current moving to ESOO low	Lower than ESOO low
Number LNG trains			
Committed	6	6	6
Additional**	Outcome of modelling	Outcome of modelling	Outcome of modelling
Oil prices	Moving to USD140	Moving to USD110	Moving to USD95
Carbon price			
Pre-2018	Commonwealth Treasury Core scenario	Between high and low	Near floor price
Post-2018	$57 by 2030	$40 by 2030	$24 by 2030
USD/AUD exchange rate			
Pre-2018	1.05	1	0.95
Post-2018	1	0.9	0.8

Source: IES (2012)

Reserves development scenarios

The LNG proponents are currently developing and stockpiling reserves to support the committed LNG projects. The level of reserves held by each LNG proponent is shown in Figure 8.

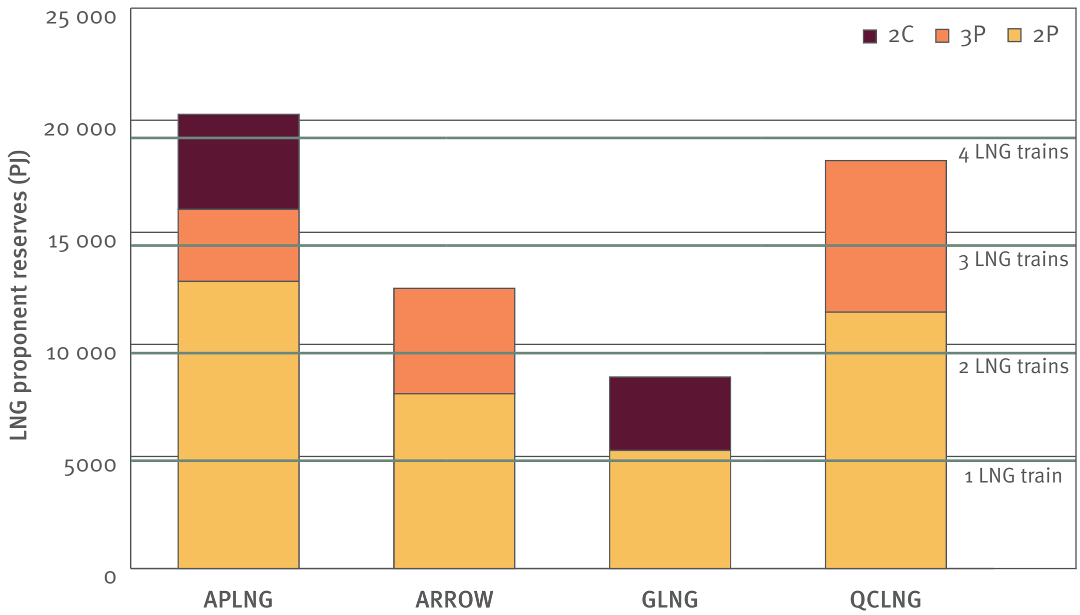


Figure 8 LNG proponent reserves at 31 December 2011 (PJ)

Source: IES (2012)

Future reserve levels will be determined by the current level of reserves, less the drawdown of reserves to meet domestic and export demand plus the development of new reserves. The rate at which new reserves are developed is critical to future supply capability.

The history of CSG reserves development (see Figure 9 overleaf) shows a significant increase since about 2005, a maximum annual increase of 14 933 PJ in declared 2P reserves in 2010, followed by an increase of only 2079 PJ in 2011. The drop in reserves declared in 2011 was due to weather effects in 2010–11.

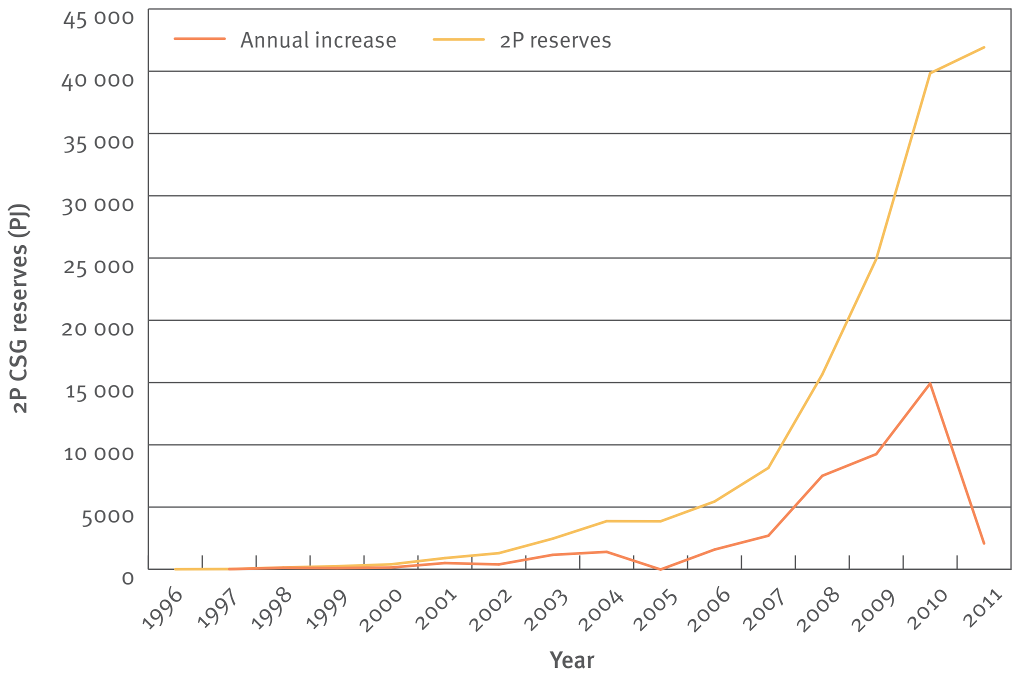


Figure 9 *Total CSG annual 2P reserves and annual increase (PJ)*

Source: IES (2012)

Given the variation in declared 2P reserves growth, in looking forward, IES assessed the expected and potential variation in the rate at which 2P reserves will be developed. This was undertaken by a consideration of:

- the percentage of (3P-2P) / 2C / (3C-2C) that will realise 2P reserves—referred to as conversion efficiency
- the time taken for the conversions (3P-2P) to 2P, (3C-2C) to 2P and 2C to 2P to occur—referred to as conversion time.

Conversion time and conversion efficiency

Factors that influence conversion efficiency and conversion rate are well productivity and drilling rates (that impact the rate at which wells are developed). Below-standard performance, in either drilling rates or well productivity, could impact the ability of LNG proponents to reach the level of reserves required to underpin the current LNG trains under construction and supply gas to the domestic market through long-term contracts to domestic users.

It was assumed that expected weather conditions over a number of years would result in a conversion period of 5 years, and that weather conditions below and above that expected would result in the conversion period being 6 and 4 years respectively.

From the three scenarios of reserve conversion efficiency, three scenarios of reserves development that combine reserve conversion efficiency and reserve conversion assumptions were developed. These were labelled 'above planned', 'planned', and 'below planned' (Table 5).

Table 5 *Reserve development scenarios*

Conversion rate Conversion efficiency	High	Medium	Low
High	Above planned		
Medium		Planned	
Low			Below planned

Source: IES (2012)

The conversion efficiencies and conversion rates presented in Table 5 correspond to annual 2P increases in the range of about 3500 to 9500 PJ with an expected increase of about 5000 PJ.

Also modelled were options to the operating rules for three 'modes'. These were the cooperation between the LNG proponents and the inclusion of prospective reserves. The name of the options and description is shown in Table 6.

Table 6 IES Gas Reserves Availability Model (GRAM) operation rule scenarios

Mode	LNG proponents	Prospective reserves
Base	Non-cooperative	Included
Sensitivity 1	Cooperative	Included
Sensitivity 2	Non-cooperative	Not included

Source: IES (2012)

Severe weather delays reserves appraisal drilling programs

For the second year in succession, extreme wet weather conditions impacted the Bowen and Surat Basins during the 2011–12 summer. After 10 years of dry and drought conditions prior to 2010–11, severe rainfall and floods in summer 2011–12 again hampered access to gas wells while causing minimal damage to infrastructure and CSG production.

The adverse weather conditions had a major impact on the appraisal and development activities underway to prove up CSG reserves to underpin LNG export.

In addition to limited access to land due to flooded roads (mostly over short periods), the major constraints were ground conditions that delayed drilling and the inability to establish and operate multi-well pilot operations, partly due to the inability to handle and process co-produced water as most water storage dams were full.

To mitigate the delays, the LNG project proponents have increased the number of drilling rigs (particularly production drilling units), introduced single pad and directional drilling processes, reprogrammed field development schedules and entered into some early phase gas swapping arrangements with those that have slightly later start-up schedules.

Reference case

The reference case was used to model potential gas reserves outcomes and was developed by IES to represent the most likely and realistic representation of how the market would develop, using:

- medium growth outlook
- medium LNG train development (8 trains by 2020, 12 trains by 2030)
- planned reserve development (medium reserve conversion efficiency, medium conversion rate)
- GRAM model operated in base mode scenario to model:
  - prospective resources included
  - LNG proponents that do not cooperate with each other (meaning that proponents with surplus reserves do not sell to proponents with a shortage of reserves).

LNG in the scenarios

Two future demand growth scenarios (labelled low and high) of LNG development were developed by IES. Using a primarily World Bank–based forecast estimate of gross domestic product growth for 2012 and 2013, growth extrapolated for the period up to 2020 provides a conservative 2020 low demand scenario (given the modest growth rates incorporated for the Asian region of approximately 4 per cent). The low demand scenario results in a forecast LNG demand of 332 MT in 2020 and 470 MT in 2030, which represents an overall growth rate of approximately 3.5 per cent per annum since 2011. In the period to 2020, potential supply options (uncommitted projects) greatly exceeds the forecast capacity shortfall.

The 2020 high demand scenario assumes higher LNG growth in Europe, South America and across the five major LNG-consuming countries of Asia. The high scenario results in a forecast LNG demand of 425 MT in 2020 and 800 MT in 2030, which represents an overall growth rate of approximately 6.5 per cent per annum since 2011.

Table 7 LNG demand scenarios

	2020 MTPA			2030 MTPA	
	Committed capacity	Additional demand	Shortfall	Additional demand	Total demand
Low demand (assumes extrapolation of 3.5% per annum global LNG growth)	318	332	14	138	470
High demand (assumes extrapolation of 6.5% per annum global LNG growth)	318	425	107	375	800

Source: IES (2012)

LNG price assumptions

The modelling assumed 6 LNG trains are committed and that these would begin operation prior to 2016 (APLNG—2 trains, QCLNG—2 trains, GLNG—2 trains).

The LNG outlook has changed since 2011, with substantial competition for LNG sales appearing on the world market—for instance, the Cheniere projects approval to export LNG from the United States (US).

Nevertheless, the large deficit in LNG requirements means that potential remains for additional significant developments. This is causing additional uncertainty in relation to LNG prices and the economics of additional LNG trains at Gladstone.

LNG pricing structure

LNG contracting terms vary across different international trading regions. In general, the delivered price of LNG depends primarily on the price of crude oil (using the Japan Crude Cocktail (JCC)) and the US dollar to Australian dollar conversion rate (USD/AUD), and secondarily on the link between LNG prices (in USD per million BTU or USD/mmbtu) and the JCC price (in USD per barrel or USD/bbl).

The values used in the scenarios are shown in the Table 8.

Table 8 LNG netback values at Gladstone

	Low scenario	Medium scenario	High scenario
JCC price (USD/bbl)	$95	$110	$140
Exchange rate (USD/AUD)	$0.95	$1.00	$1.05
Post 2018	$0.80	$0.90	$1.00
Slope	0.10	0.12	0.13
LNG netback price (AUD/GJ)	$4.40	$9.00	$14.00

Source: IES information (2012)

The Asian region is the customer for the Queensland LNG export projects. Other features of Asian contract pricing sometimes include:

- the ‘primary slope’, which represents the linkage to crude oil and is expressed as a decimal
- an ‘S-curve’ mechanism, which introduces a lower ‘primary slope’ value to apply when crude prices are in a low or high range (‘secondary slope’), protecting sellers at low crude oil prices and buyers at high crude oil prices (‘kink points’)

or

- ceiling/floor constraints usually linked to crude oil prices.

New term contracts to Asian buyers over the past several years have displayed the following elements within the traditional formula:

- values for slope in the range 0.1395 to 0.154
- values for 'b' reflecting shipping costs for delivered sales or close to zero for free on board (FOB) sales
- increasing adoption of 'S-curves' (but not in all cases), with low and high crude price trigger points often at around US$50/bbl and US$90/bbl respectively.

Looking forward, IES considers that the current pricing formula for LNG sales in Asia would remain (i.e. linked to JCC via the formula's slope), but that the slope could reduce to between 0.10 and 0.13.

Carbon pricing in the modelling scenarios

In electricity generation, carbon pricing should have the effect of making gas more competitive with coal, but simultaneously less competitive with low- or no-carbon options such as renewables. A secondary effect of carbon pricing on gas is the expected growth of peaking gas generation plants to support intermittent renewable generation such as wind.

The basis of the scenarios is that the current legislated carbon pricing scheme continues and:

- a high price outlook is taken to be prices at the federal treasury core scenario (this is consistent with AEMO and ACIL interpretations of the decentralised world scenario)
- a low price outlook is taken to be prices near the floor price (this is different than the AEMO interpretation for this scenario that has prices at $23 for the first 3 years and near $0 after that)
- a medium case is taken to be between the high case and the legislated floor price.

See Figure 10 for a graph of the scenario carbon prices.

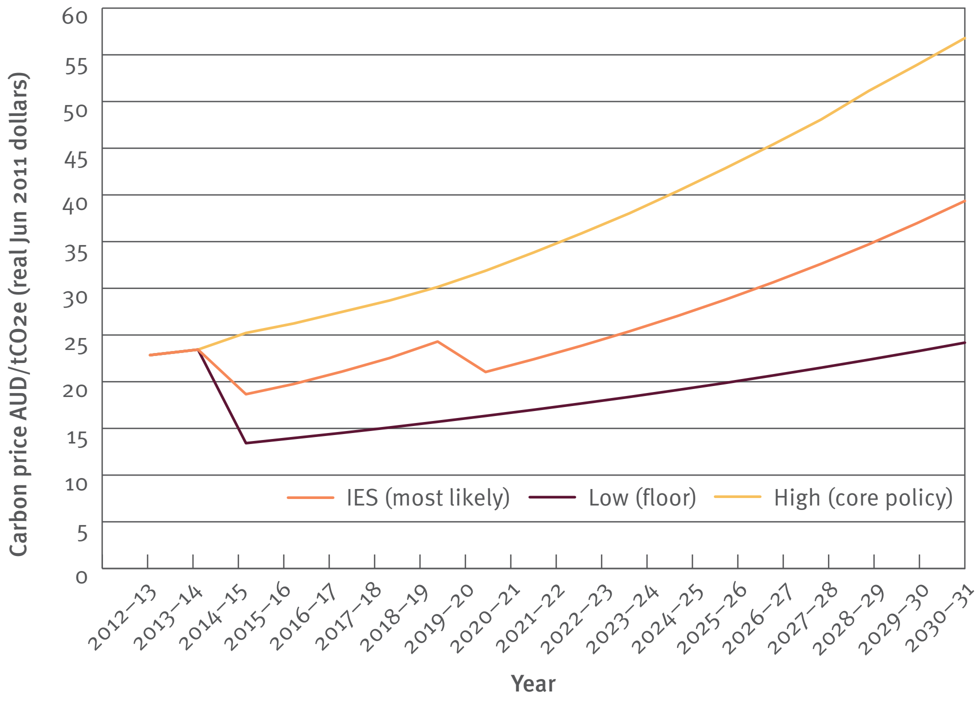


Figure 10 Scenarios of future carbon emissions price ($/tonne)

Source: IES (2012)

Gas production cost assumptions

For the purposes of modelling for the 2012 GMR, IES assumed current gas production costs to be:

- conventional gas – $3.50/GJ to $4.00/GJ
- CSG – $2.65/GJ to $4.42/GJ.

For CSG, the costs of producing gas vary considerably across fields. The review showed costs currently in the range of $2.65/PJ to $4.42/PJ. As more remote and marginal locations are utilised, the costs would be expected to increase to about $7/GJ at reserve levels of 80 000 PJ.

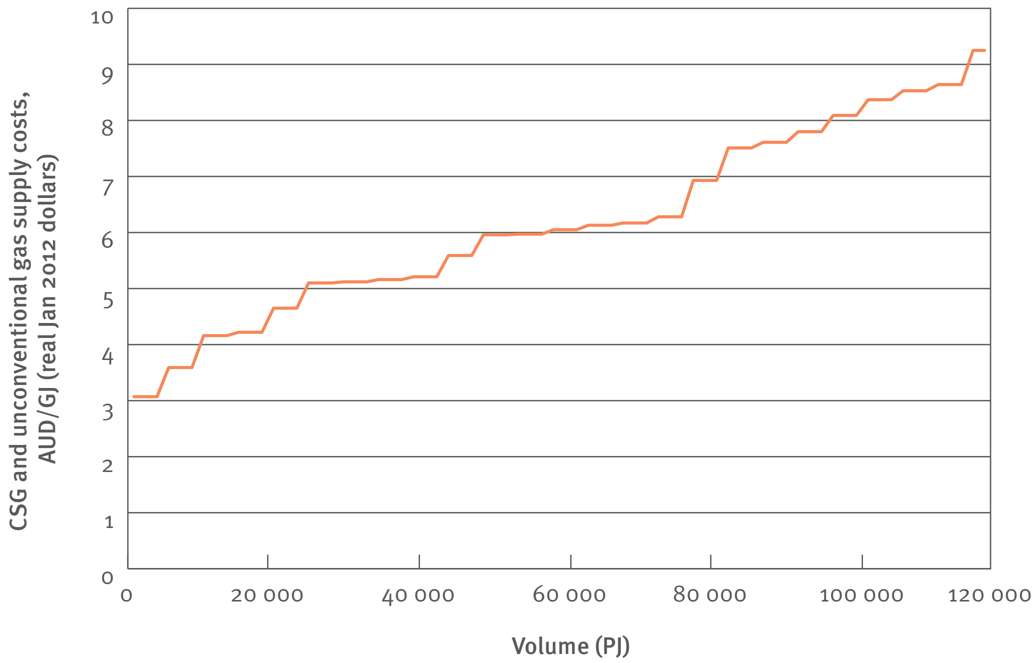


Figure 11 CSG supply curve ($/GJ)

Source: IES (2012)

The development and economics of conventional gas is very different from that of CSG. The main resources are the Cooper Basin and offshore in the Gippsland and Otway Basins. There are no ramp-up gas issues. The economics can be highly influenced by the oil recovered, which may be of significantly more value than the gas obtained.

The cost structure of conventional gas is thus dependent on many issues and an assessment, including that of oil, is difficult to assess. Assessments of supply cost have the Gippsland and Otway Basins in the order of $3.50/GJ and the Cooper Basin slightly higher in the order of $4/GJ.

These gas resources may become an economically viable alternative supply to Queensland under conditions of high Queensland wholesale gas prices and low production costs.

Future oil prices

IES developed and used (without reference) the following oil price outlook for the three economic scenarios being considered. These prices (shown overleaf) are consistent with the range of prices that could be expected, noting that in practice oil prices can be expected to show volatility through time.

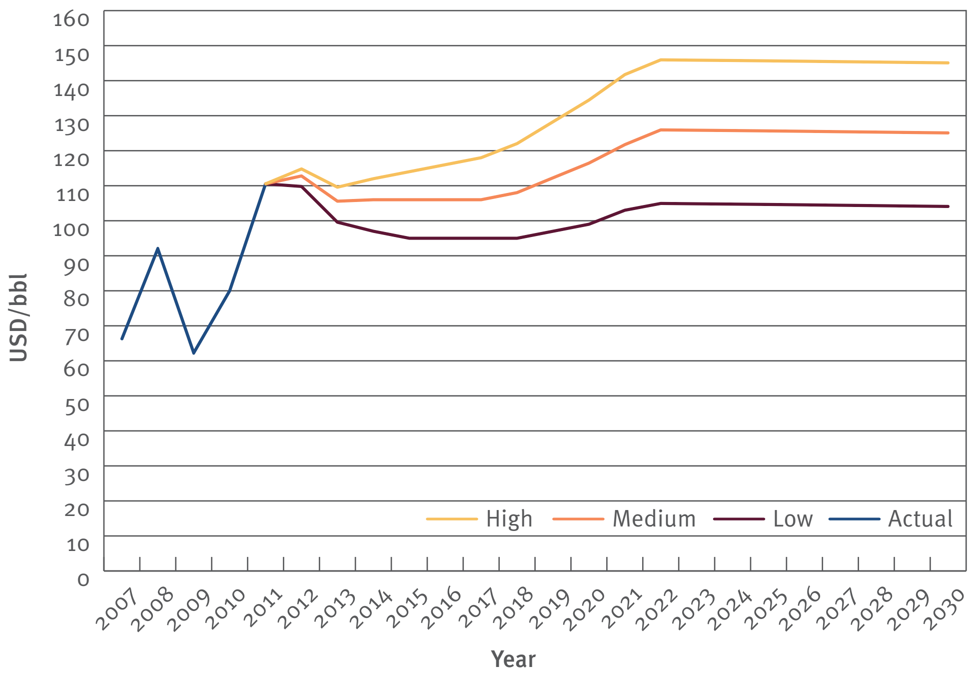


Figure 12 Scenarios of future oil price (USD/bbl)

Source: IES (2012)

Gas demand in the scenarios

Gas demand, excluding LNG and non-GPG, was based on the 2011 AEMO GSOO. The basis of the gas demand projections for each of the three economic growth scenarios are as follows:

- The high scenario is based on the 2011 AEMO scenario 'decentralised world'.
- The low scenario is based on the 2011 AEMO scenario 'slow rate of change'.
- The medium scenario is between the high and low scenarios.

These demand projections were modified using information obtained from meetings held by IES with large gas users associated with this study. LNG demand was part of the output of the scenario and was consistent with the scenario description and LNG economics.

Domestic gas price assumptions

Indications are that gas prices are in the process of moving from cost-based to export-opportunity value. Export-opportunity value is based on the price of LNG sold ex-Gladstone, less the costs associated with liquefaction and upstream pipeline transportation (assumed to be $5/GJ). This is referred to as netback pricing.

Netback price (to the ex-field location) is determined as the LNG FOB export price less the costs of liquefaction and pipeline transportation.

The costs of liquefaction and upstream pipeline transportation can vary depending on many factors such as plant size, location and exchange rate.

IES assumed a generic Gladstone LNG project liquefaction cost and upstream pipeline transportation cost, with a combined cost of $5/GJ.

IES identified two possible future price formation models:

- **Domestic prices based on supply costs** – Under market conditions where the level of LNG exports is fixed (with no expected increase) and sufficient reserves have been developed and set-aside for that purpose, additional domestic sales would not impact LNG export sales. Under such conditions, the LNG sector would be effectively ring-fenced from the domestic market and domestic prices would be formed on the basis of cost and the level of competition.

- **Domestic prices internationally linked** – Under market conditions where LNG proponents are developing reserves to support an increasing level of LNG exports, additional domestic sales would impact the date of financial close of an LNG export facility or the ability to sign long-term supply contracts. Under such conditions, all gas would have an LNG export-opportunity cost and there would be a close link between domestic prices and LNG netback prices.

It may be that the LNG developers are unsure of the economics of additional LNG export trains, but determine that a medium-term strategy of stockpiling reserves is appropriate pending a future decision on LNG. This could be described as domestic prices being loosely internationally linked. The modelling undertaken was required to identify the conditions under which price formation process should be the dominant influence.

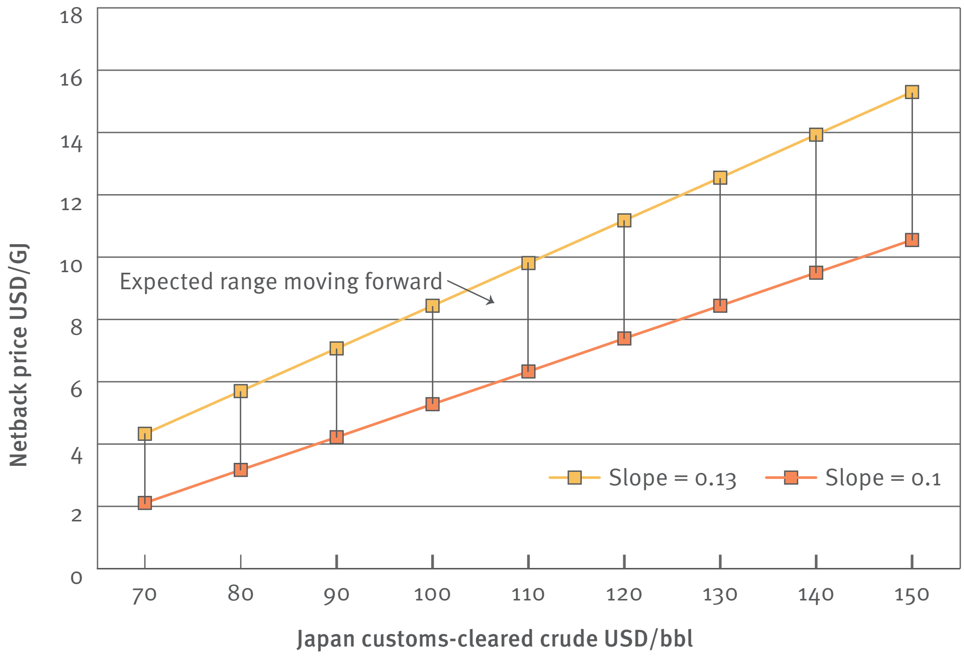


Figure 13 *Netback price (ex-field) range as a function of JCC ($/GJ)*

Source: IES (2012)

Gas demand

Demand for gas within eastern Australia is considered in two broad segments—domestic and LNG export. Domestic demand is further broken down into customer segments.

Customer segments

- **Mass market** customers are residential, small business and larger commercial and industrial customers who are supplied principally from distribution mains.
- **Large industrial** customers consuming significant quantities (typically more than 1 to 2 PJ per annum) and are supplied principally from transmission mains. Large industrial customer demand was projected using information available in the market and following consultation with the operators and proponents of large industrial projects. Utility and large industrial demand are modelled together because they represent the section of the gas market not directly linked to electricity generation and gas export markets.
- **GPG** is gas for power generation, including large cogeneration projects. GPG was modelled based on assumptions related to electricity demand, timing and price of carbon emissions, renewable energy schemes, fuel prices and availability of alternative fuels and technologies.

Domestic customer contracting

In highly competitive markets, price is set by the short-run cost of the marginal product being produced. Historically, the gas markets in Australia have not had a highly competitive structure and prices have mostly reflected the all-up costs of supply. This has been in the range \$3/GJ to \$4/GJ.

The advent of gas export sales (via LNG) from Queensland connects the east coast gas market gas prices to internationally traded gas (LNG) prices, and it would appear that prices are now being based on export-opportunity value. This means that domestic users seeking to recontract supply are for the first time competing with LNG and the initial start of the LNG export facilities when contracting for ongoing supply and new projects.

When graphed, demand appears as a straight line, but the underlying contracts reach term and require recontracting at different times. This timing is critical for assessing market activity. Existing east coast supply contracts reached a peak around 2008, which means as a whole there will be a very high contract replacement requirement in 2018 due to the termination of contracts (primarily in Victoria). In Queensland, the majority of major users must recontract at least part of their load in the period 2015 to 2016. LNG project development combined with the need for existing major users to recontract is placing pressure on reserves development to underpin contracting.

Domestic demand modelling outcomes

Queensland has a gas consumption of around 240 PJ per year and the eastern Australia gas market consumption is around 718 PJ per year. LNG is the dominant force in the Queensland gas market moving forward (as can be seen in Figure 14 opposite). Figure 14 shows Queensland's gas demand and projected gas demand for LNG export. It assumes domestic demand is static at 2011–12 levels, with 6 LNG trains by 2015–16 and a further 2 trains by 2020–21.

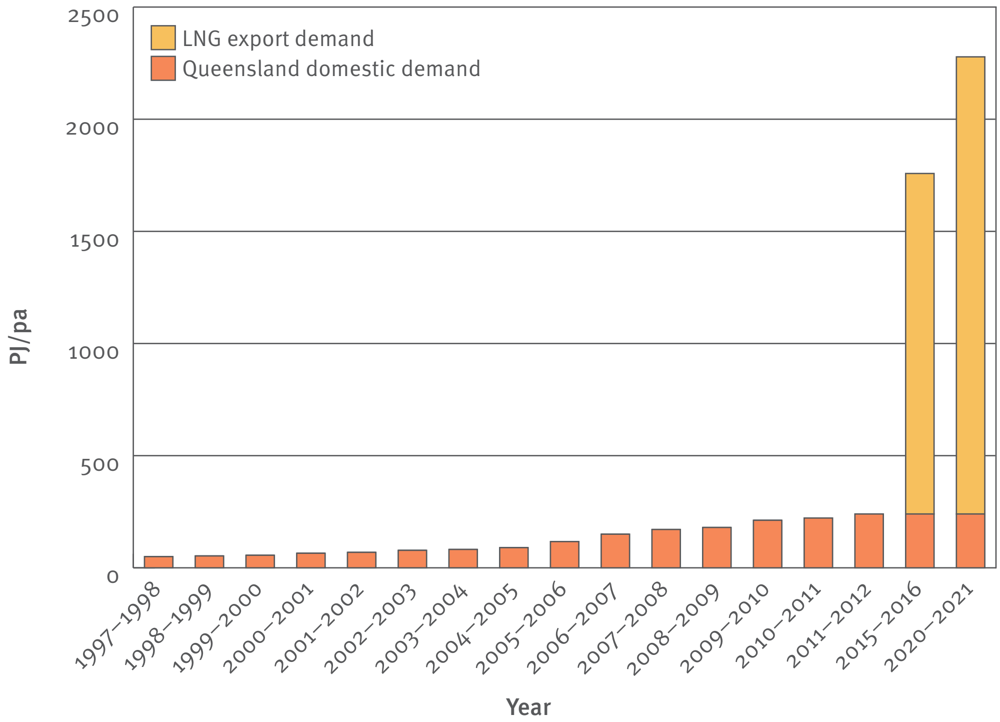


Figure 14 Queensland domestic gas demand and projected gas demand for LNG exports

Mass market

As part of the AEMO GSOO publication, projections of mass market gas demand and large industrial demand by the state are provided under a range of economic outlook scenarios. These were used by IES as the basis of these demands in the economic outlook scenarios developed in this report (labelled high, medium and low).

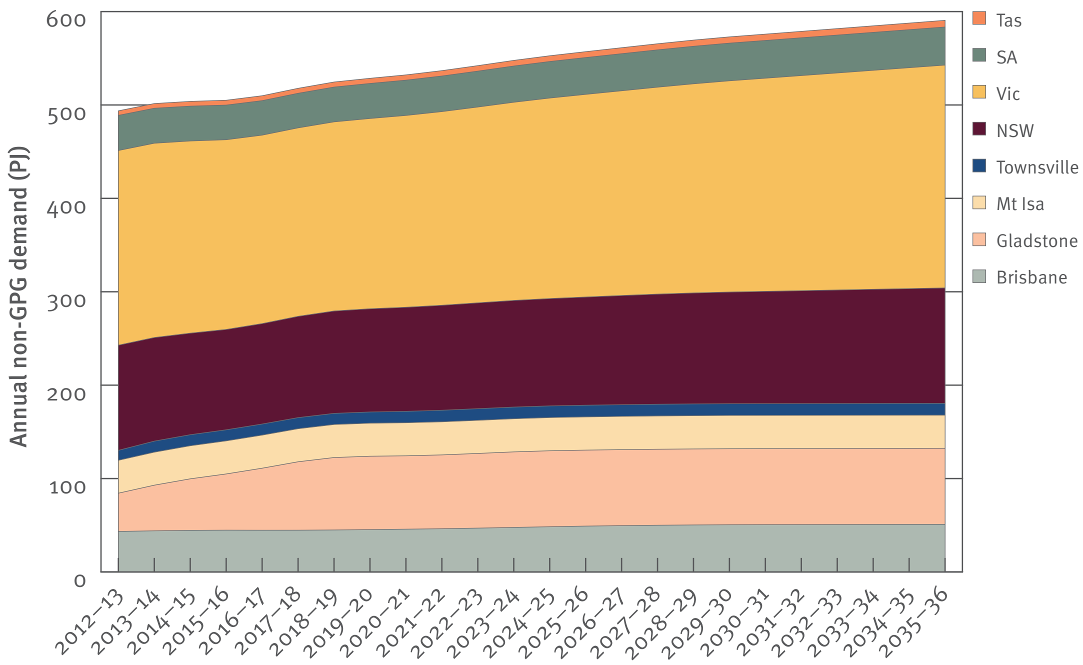


Figure 15 AEMO 2011 GSOO demand outlook (PJ per annum)—excludes GPG and LNG exports

Source: AEMO (2011)

Queensland large industrial

The large industrial customers in Queensland comprise over 70 per cent of Queensland gas demand (excluding GPG and LNG exports). The economic modelling showed that the level of large-user demand in Queensland was greatest for the low growth scenario. In the high scenario, the gas requirements of Queensland large users reduced, but there was a relatively small increase in gas use in the other states. The change in large-user industrial demand for the high and low scenarios compared with the medium scenario (current volumes) is shown in Figure 16.

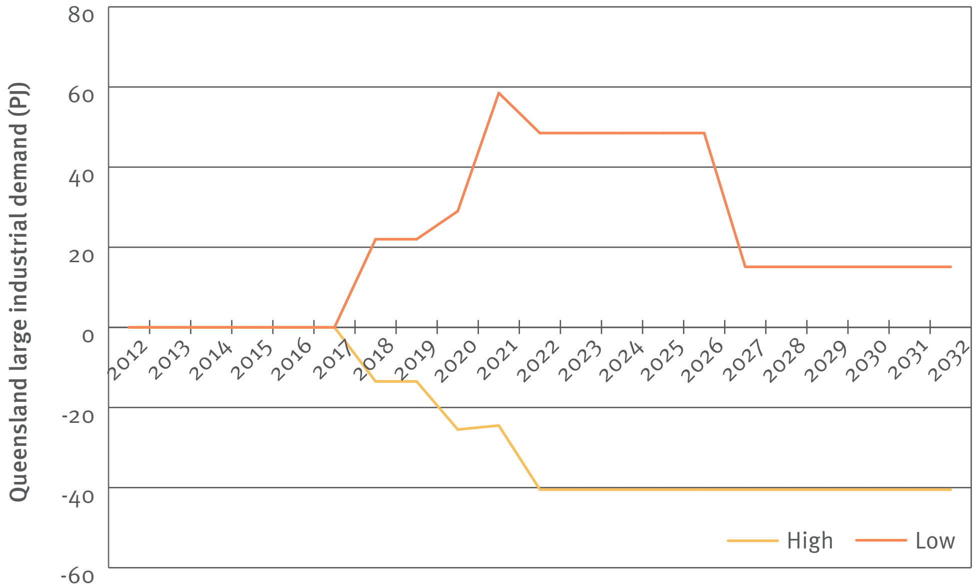


Figure 16 Queensland large industrial demand changes from the medium scenario (PJ)

Source: IES (2012)

Gas power generation

On average, 12 per cent of electricity in the National Energy Market (NEM) was generated by gas in the financial years 2009 to 2011. In the NEM as a whole, the gas consumption by power generators has increased from 101 PJ in the 2009 financial year to 124 PJ in 2011, confirming a recent general trend to more gas-fired electricity generation.

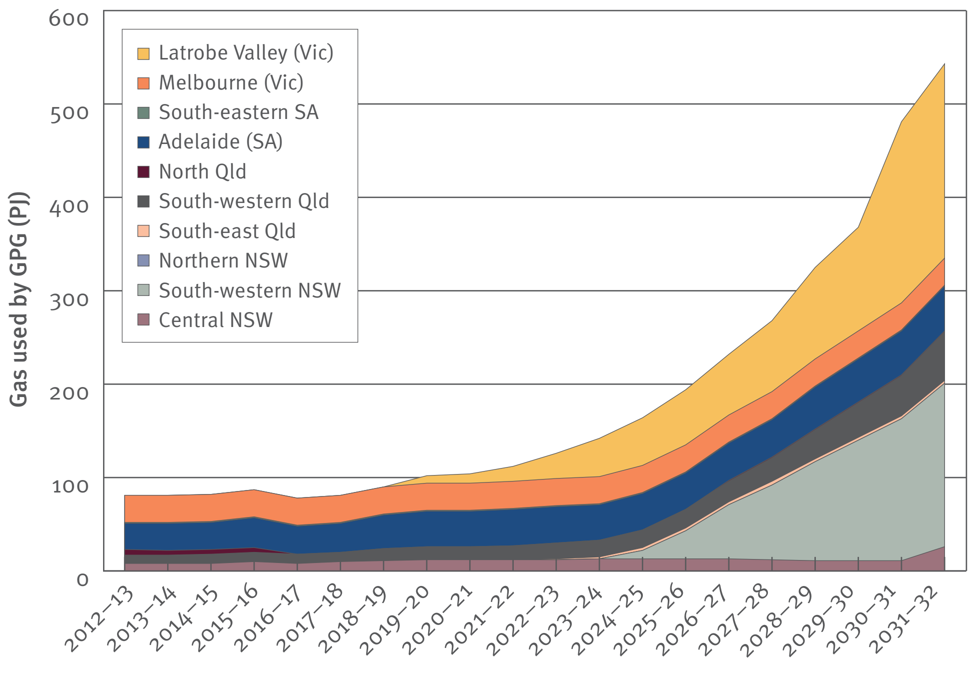


Figure 17 Gas usage for power generation by location for the medium growth/medium LNG scenario (PJ)

Source: IES (2012)

GPG was envisaged to continue to play an increasing role in the generation of electricity due to the lower carbon emissions of gas generation compared with coal generation. However, the economic modelling showed that the level of GPG did not change significantly between scenarios to 2020, and the increase in the level of GPG over the period to 2020 is small under all scenarios.

This reflects the state of the electricity market (sufficient generation and low load growth) and the economics of gas generation in light of a low carbon price outlook and higher gas costs. Post-2020, GPG increases significantly with the level of increase being scenario sensitive.

Another issue impacting future development of GPG in Queensland and elsewhere in the NEM is securing gas. Parties that cannot secure a viable supply may be unwilling to invest in GPG. However, there are synergies associated with GPG that can result from integration of generation with other steps in the supply chain. Synergies and risk mitigation are greatest for a party with all of the following:

- its own low-cost gas near electricity transmission line(s)
- a captive electricity market
- a captive gas market.

Another type of synergy is electricity demand together with demand for low/medium pressure steam in close proximity to each other, which can make cogeneration viable.

LNG export

By the end of 2015 (subject to possible delays), there are likely to be 6 LNG trains in operation at Gladstone with a total gas consumption of 1518 PJ per year.

Table 9 Committed LNG trains and annual demand volumes

Project	No. of committed trains	Gas use per train PJ per annum	Scheduled start-up
Australia Pacific LNG (APLNG)	2	270	2015
Gladstone LNG (GLNG)	2	234	2015
Queensland Curtis LNG (QCLNG)	2	255	2014
Arrow LNG	0	260	2017

Source: IES (2012)

The LNG developments occurring in Queensland mean there are a potential range of outcomes that may emerge in the longer term. These are considered in context to total gas demand in Queensland and the east coast gas market.

Gas pricing

The modelled price outcomes for the domestic market reflect the assessment of supply costs and the pipeline tariffs. The key observations from the IES economic modelling of prices are:

- prices reflect the underlying economic costs—ramp-up gas over the next 2 to 3 years may have prices lower than in the projections, but based on the supply curve presented by IES, costs would be expected to reflect economic costs under a competitive industry structure
- gas prices are sensitive to the level of LNG development to the extent they require the development of gas sites to be more costly than would otherwise be the case—costs are the critical issues in this circumstance.

The sensitivity of reserve availability to LNG outlook meant that gas contract prices could be linked to LNG export prices, with a discount depending on the number of projected LNG developments that would occur. However, this is a complex dynamic where the key drivers are exogenous to Australia, are difficult to assess and largely based on factors that include LNG proponents' longer term aspirations, oil price outlook to the extent this impacts LNG development economics and competing LNG developments in North America and East Africa.

Gas pricing outcomes—Queensland

The resulting range of average Queensland contract price outcomes based on the different outlooks of oil price (at a slope of 0.12) is shown in Figure 18.

A high demand LNG development outlook accompanied by high projected oil prices would likely lead to domestic gas prices increasing to over $10/GJ by 2015 and gas scarcity for domestic contracts.

A modest oil and LNG development outlook could see prices in the order of $6.50/GJ by 2015. Under the same scenarios, gas prices in 2020 would be in the range (high to low) of $12/GJ to $7/GJ.

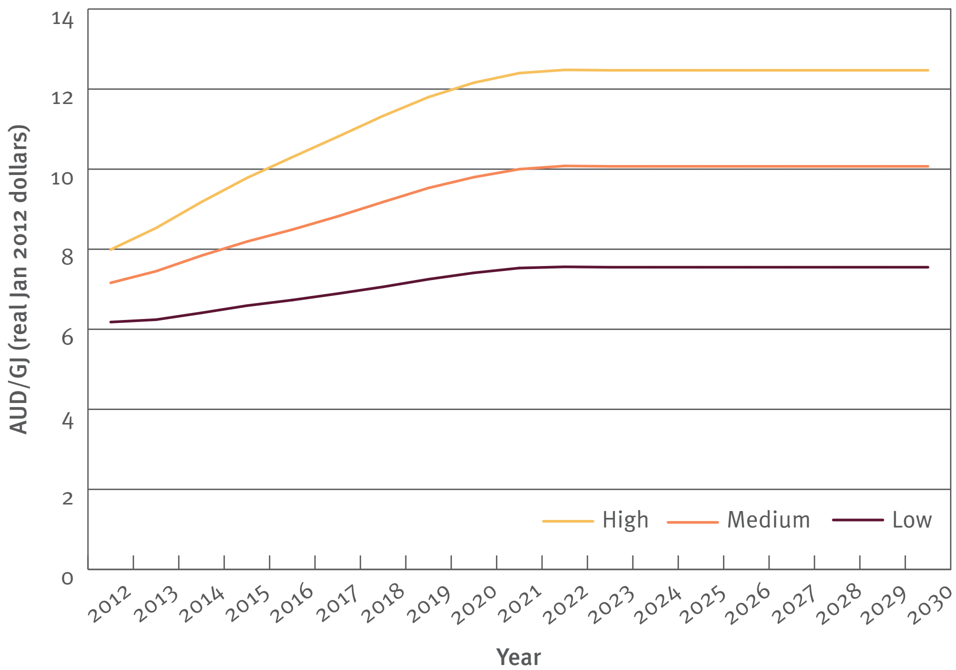


Figure 18 Range of Queensland long-term ex-field gas contract price outcomes ($/GJ)

Source: IES (2012)

Gas pricing outcomes—Queensland submarkets

The eastern Australian gas market is, in reality, a series of interconnected markets. Queensland, more so than any other eastern Australian state, also has a series of submarkets with different characteristics. For the 2012 GMR, the state markets are modelled as a group and the Queensland submarkets are considered separately as Brisbane, Gladstone, Mount Isa and Townsville. Wallumbilla, while not a true demand centre, was also modelled as it is a focal point for gas movement and pricing.

When prices are considered for the submarkets, the variations can be seen. Some of this variation can be attributed to the different production cost of gas from different fields that supply these markets, and to the different distances gas must be transported from the fields to the submarkets. Wallumbilla prices do not include the variations to the same extent and provide a useful comparator to southern state prices.

The modelling indicates that, with the exception of Brisbane, the submarket variation will decrease over time and prices will converge. The modelling also shows a widening gap over time between Queensland gas prices and those in southern states. If this price variation bridges the difference in Queensland CSG and southern conventional gas production costs, it could underpin the flow of southern states gas to Queensland.

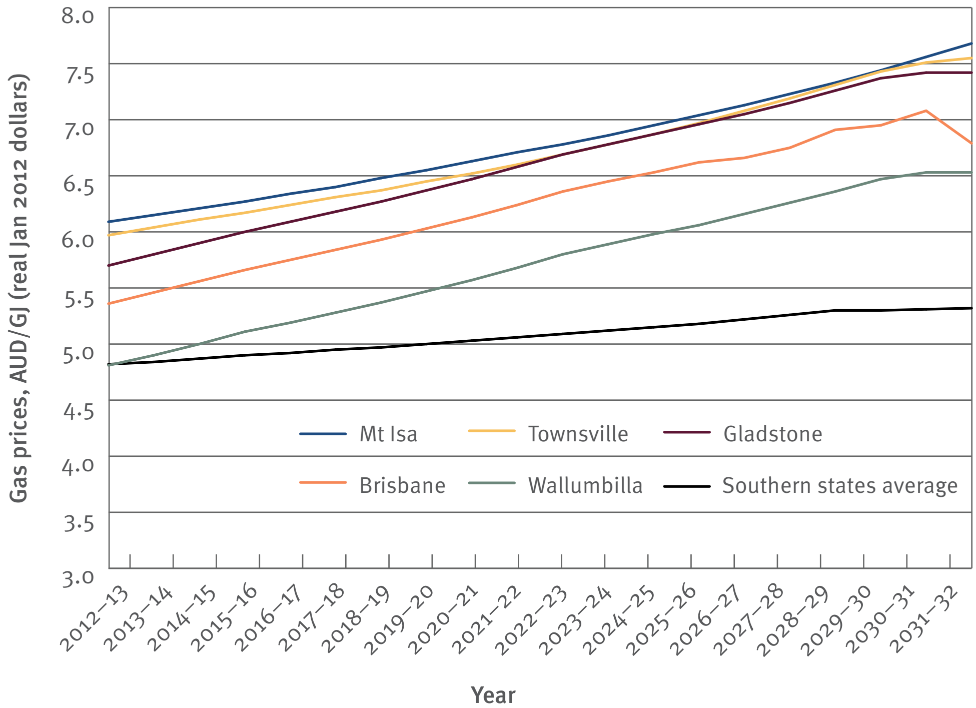


Figure 19 *Gas prices by location for the medium growth/medium LNG scenario ($/GJ)*

Source: IES (2012)

Gas reserves

Long-term contracts for gas supply are struck using 2P reserves estimates—these are the most widely quoted. In general, 2P reserves equal to the total contract gas quantity are required, although the producer may undertake to prove up sufficient reserves within a set period or on an annual basis, or agree to maintain a minimum number of years of reserves coverage at all times.

On this basis, the potential development spread of 2P reserves in Queensland is shown in Figure 20. Also shown are the total reserves required for 6 and 14 LNG trains (notionally of 4 MTPA capacity each). This illustrates that if the reserve development rate was to decrease much below the low case, the time required to develop reserves necessary to support additional LNG trains could increase substantially.

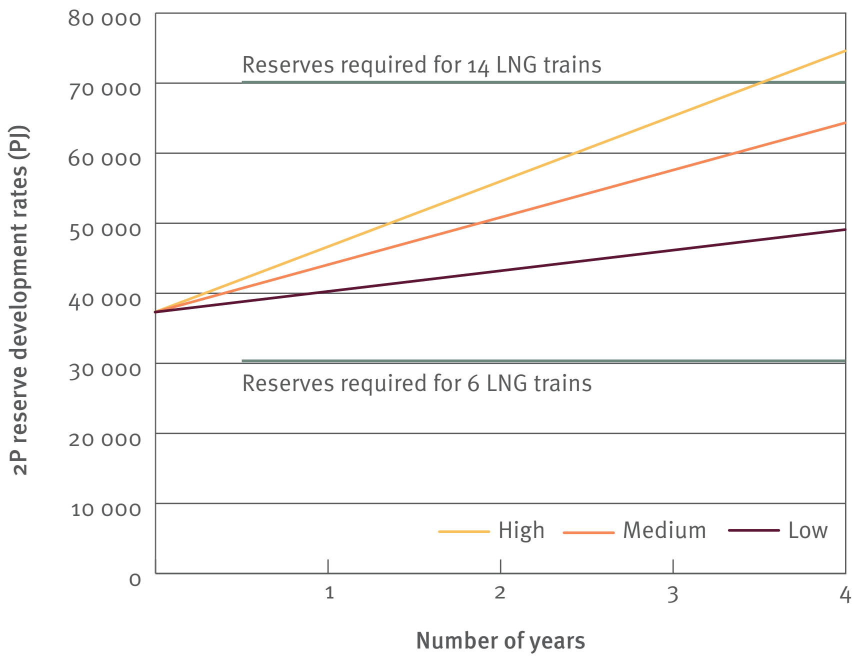


Figure 20 2P reserves development rates

Source: IES (2012)

Gas reserves classification

Commercial reserves

Demonstrated reserves that would yield a commercial return at expected prices:

- *proved (1P) reserves*
- *proved and probable (2P) reserves*
- *proved, probable and possible (3P) reserves*

Subcommercial contingent resources

Demonstrated resources for which commerciality requires further assessment:

- *low estimates (1C)*
- *best estimates (2C)*
- *high estimates (3C)*

Prospective resources

Inferred resources:

- *low estimates*
- *medium estimates*
- *high estimates*

Reserve levels

Conventional reserves holdings have been largely static through to 2000, but are now declining, while CSG reserves have grown rapidly from a zero base in 1995 to overtake conventional reserves from 2008. For the eastern Australian gas market, total 2P reserves are estimated at 50 385 PJ with CSG reserves making up 41 920 (82 per cent) of the total. Table 10 provides a regional breakdown. CSG reserves grew by 2750 PJ over 2011, compared with growth of in excess of 10 000 PJ in recent years. Queensland severe summer weather was a significant factor in the reduction in reserves growth.

Table 10 Eastern Australian 2P reserves (PJ) at 31 December 2011

2P reserves	New South Wales	Victoria	Tasmania	South Australia	Queensland	Total
Conventional	6	6 394	241	1 594	230	8 465
CSG	2 846	0	0	0	39 074	41 920
Total 2P reserves	2 852	6 394	0	1 594	38 645	50 385

Source: IES (2012)

Potential 2P reserves by company ordered from highest to lowest are presented in Figure 21 (overleaf). Potential 2P reserves represent the likely 2P reserves that will result from the conversion of 3P, 2C and 3C resources. This illustrates the ‘tiered’ nature of reserve ownership of the CSG companies.

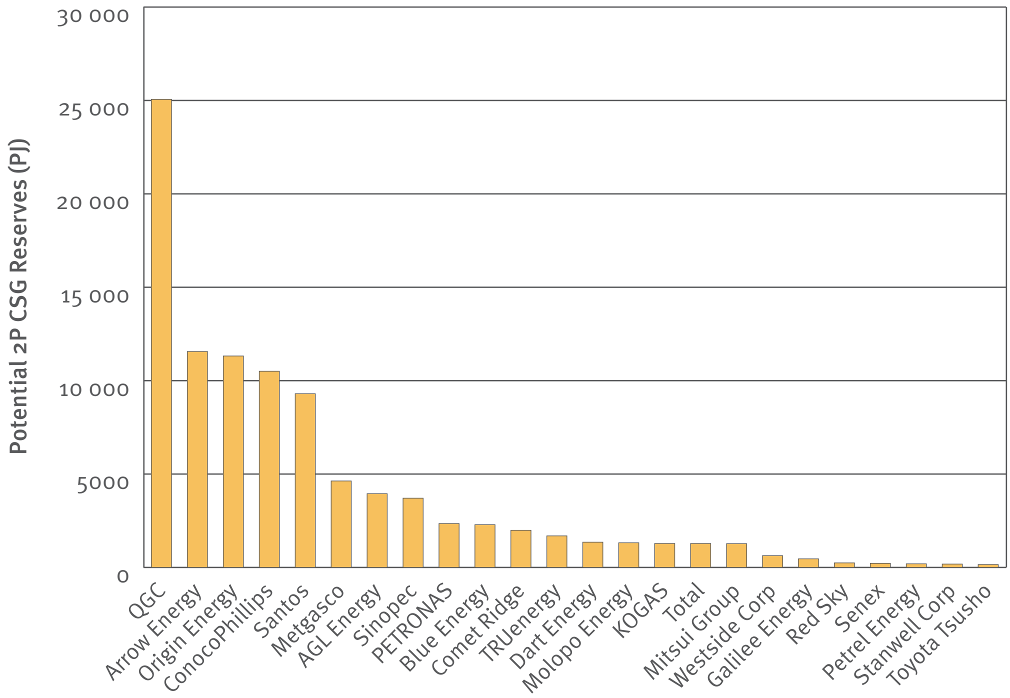


Figure 21 2P potential CSG reserves by CSG company

Source: IES (2012)

QGC has by far the largest holding of reserves, being more than twice the next tier—which consists of Arrow, Origin Energy, Conoco Philips and Santos. All of these companies have an LNG export focus.

The concentration of the ownership of the largest volume of gas reserves is shown in Figure 22, where companies holding less than 1000 PJ of 2P reserves are grouped together.

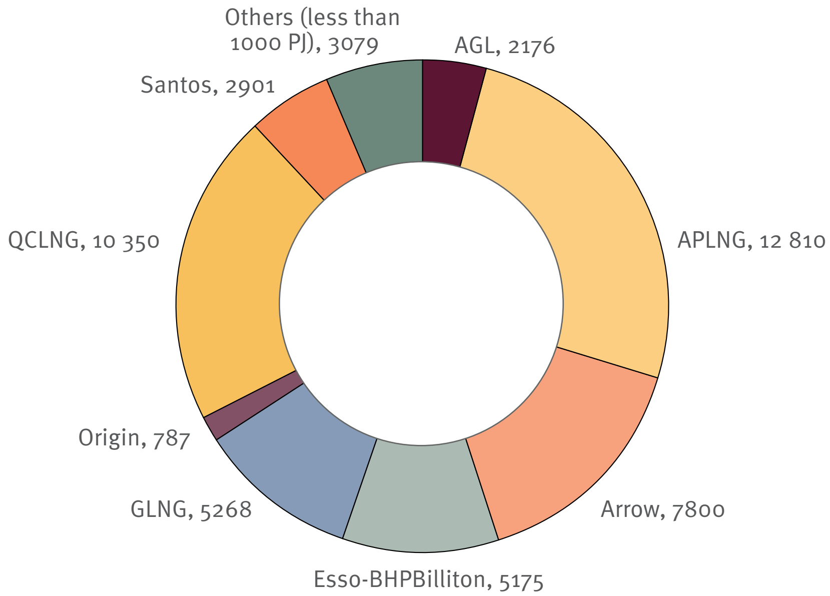


Figure 22 2P potential CSG reserves by CSG company

Source: Data sourced from IES/RLMS (2012)

The reserves modelling outcomes

Based on the range of 2P reserves development of 3500 to 9500 PJ with an expected increase of about 5000 PJ, the potential development spread of 2P reserves in Queensland is shown in Figure 23. Also shown are the total reserves required for 6 and 14 LNG trains (notionally of 4 MTPA capacity each and not related to the individual positions of the 4 proponents or geographical locations). Figure 23 illustrates that if the reserve development rate was to decrease much below the low case shown below, the time required to develop reserves to support additional LNG trains could increase substantially.

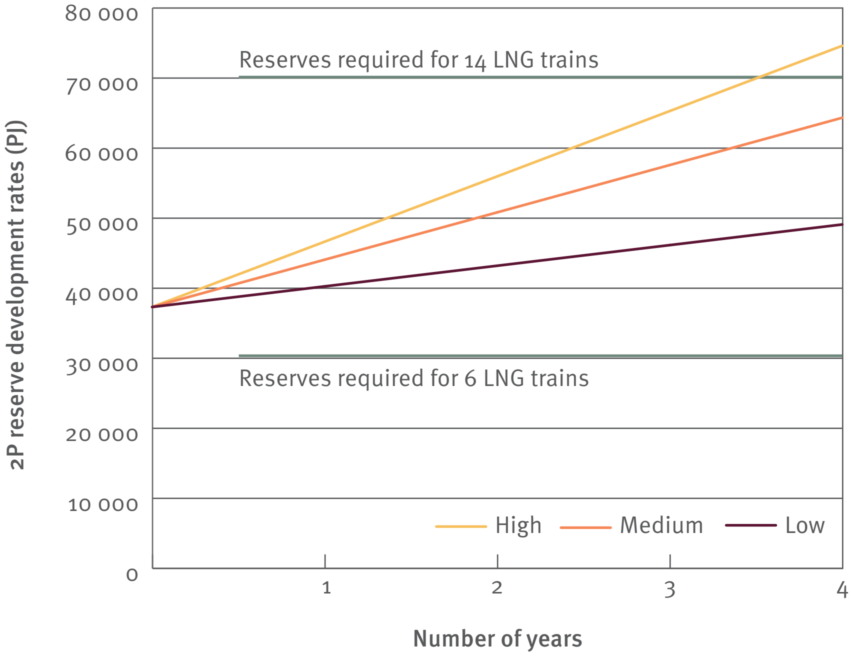


Figure 23 2P reserves development rates

Source: IES (2012)

Reference case

When the reference case is modelled, there is currently just over 2000 PJ of non-LNG 2P reserves in Queensland and the Cooper Basin. This reduces over time to a low point around 2020 to 2022, primarily due to acquisition by LNG proponents who require more reserves for their LNG trains. Beyond this point, non-aligned 2P reserves increase back to a high of around 4000 PJ due to the assumed commencement of the development of unconventional gas reserves in the Cooper Basin.

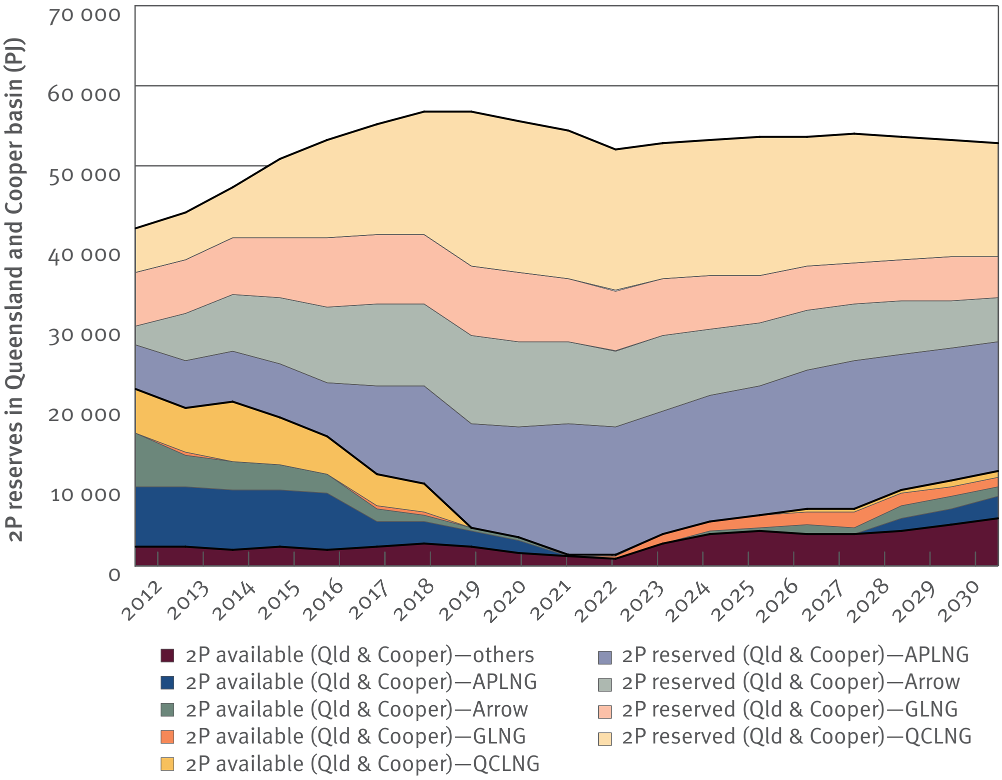


Figure 24 Reference case (base mode)—2P reserves in Queensland and Cooper Basin

Source: IES (2012)

Reserves owned by LNG proponents that are additional to their reserve requirements for operational and future LNG trains (whose produced gas is assumed to be available for sale to the domestic market) are currently estimated to be just under 10 000 PJ. The volume decreases to zero over the years to 2021, as the reserves required to be withheld for operational and future LNG train increases and as the reserves are depleted through gas production to meet LNG train and domestic demand. With the development of unconventional gas in the Cooper Basin, these reserves begin to increase once more. In total, the modelling indicates that over 8000 PJ of 3P reserves will exist surplus to LNG requirements in 2030.

Reserves that are being withheld for operational and future LNG trains grows throughout this decade, reflecting the fact that the reserves required to be withheld peaks around 2021. Based on the reserve assumptions used, GLNG has almost no reserves surplus to the 20 years of potential 2P reserves being kept for its assumed LNG trains in this decade. However, it still has substantial reserves being withheld for its LNG trains, and sufficient gas to operate the plant.

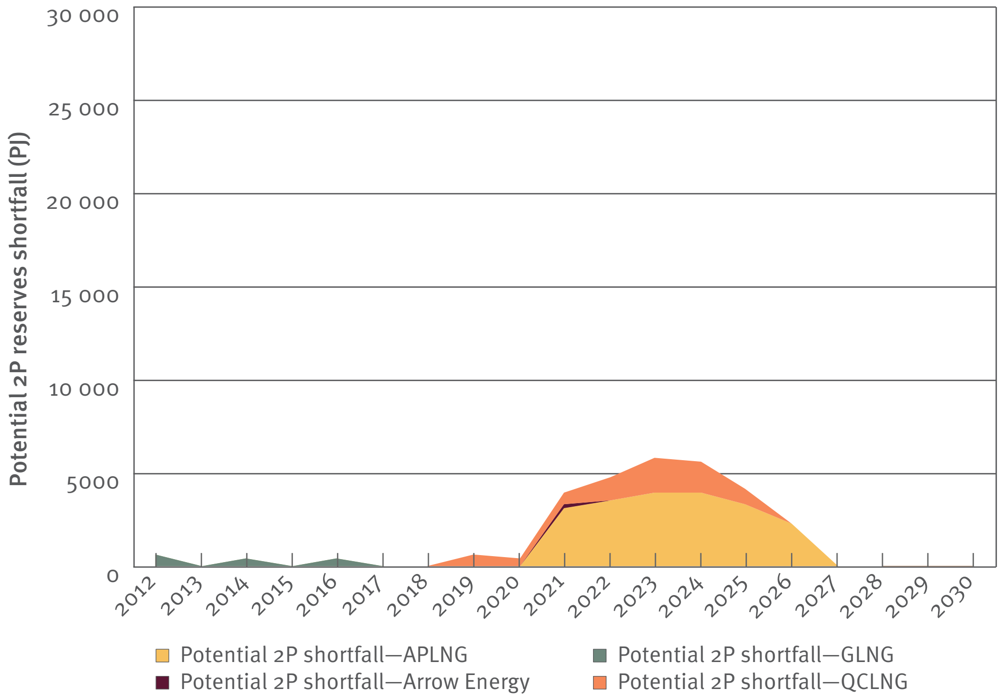


Figure 25 Reference case (base mode)—shortfall in potential 2P reserves by LNG proponent

Source: IES (2012)

Variables modelled

- **Low 2P reserve development** – When the reference case is modelled with the below planned 2P reserve development rate assumed, the available (for sale) reserves are substantially reduced and close to exhausted by 2018. There is also significantly less reserves owned by the non-LNG aligned suppliers, resulting from the continuing acquisition of reserves by the LNG proponents aiming to meet their reserve requirements. The availability of gas to non-LNG demands is very low from 2018 to 2022 when unconventional gas in the Cooper Basin is developed. This shows that the development rate of 2P reserves is an important factor in the continuing availability of gas reserves under an 8 LNG train by 2020 scenario.
- **Additional LNG trains** – When the reference case is modelled with 2 additional LNG trains by 2020 and 4 additional LNG trains post-2020 (a total of 10 trains by 2020 and an additional 6 trains post-2020), the availability of gas to non-LNG demands is very low over the middle years around 2020. This scenario indicates that:
  - » a higher reserve development rate than that assumed would be necessary from the LNG proponents if they were to develop more than 8 LNG trains by 2020
  - » as a consequence of this, reserves to the domestic market would unlikely be made available by the LNG proponents during the early years of the study period.
- **Reduced number of LNG trains, low domestic demand** – When the reference case is modelled with 2 less LNG trains by 2020 (6 in total by 2020), 4 less LNG trains post-2020 (total of 12 trains by 2030) and low domestic demand, it shows that spare reserves are available throughout the study period, owned by both LNG proponents and non-LNG businesses. On the basis that there was no aspiration to develop LNG trains beyond that assumed here, there would be a considerable amount of available gas, and it would be expected that this would be made available to the domestic market.
- **Cooperation between LNG proponents** – When the reference case is modelled with the LNG proponents assumed to be fully cooperative (that is, they act as a single entity, sharing all LNG trains and gas reserves), they need to acquire overall less reserves owned by non-LNG proponents in order to fulfil their LNG reserves requirements. This difference is due to the fact that some LNG proponents currently have more reserves than they need for their assumed LNG train development, and that under a cooperative sensitivity these reserves may be used by other LNG proponents who are short of the reserves they require. Without cooperation, these other proponents instead acquire reserves from non-LNG businesses, which adds further pressure on the reserves available to the domestic market.

- **Prospective reserves** – When the reference case is modelled with prospective reserves not included in the model prior to 2021, the results appear very similar to the base mode when prospective reserves are included. This is because it is assumed that the bulk of the prospective reserves (primarily located in the Cooper Basin) start being developed to 2P reserves only after this time. Under an 8 LNG train scenario, the reserves required to be withheld for the LNG trains are greater than the total of the proven, probable and contingent reserves in Queensland and the Cooper Basin, resulting in a full acquisition of these reserves by the LNG proponents.

Reserves modelling outcomes

All four LNG proponents are modelled to experience a shortfall in their required gas reserves for their LNG plant at some stage during the study period. This occurs in the first few years for GLNG and in the middle to later years for the other three proponents. Over this period of time, the LNG proponents are expected to be acquiring available reserves located in Queensland and the Cooper Basin from non-LNG businesses.

No gas supply shortfalls occur during the study period modelling, but this is dependent on the time and efficiency rates of conversion of reserves to 2P, and of 2P reserves to produced gas. It also assumes that LNG proponents would make their surplus gas reserves available to non-LNG gas users.

In summary, with LNG developments limited to 8 trains by 2020 and an additional 4 trains by 2030, there are sufficient reserves to provide gas for the domestic market and any operational LNG trains over the study period. However, the rate of reserve development is insufficient for the LNG proponents to fully meet the reserve requirements for their planned LNG train development post-2020. For this reason, it is possible that the LNG proponents may choose to withhold their available reserves from the domestic market in the first few years in order to reduce their reserve shortfall later in the study period.

The results also indicate that with the assumed LNG train development scenario, the gas market is expected to tighten further to 2021 before unconventional gas located in the Cooper Basin becomes available.

The modelling led IES to conclude that over the next 2 to 4 years leading up to the commissioning of the 6 committed LNG trains, the reserve holding of the LNG proponents would have option value in maintaining opportunities for decisions on additional LNG trains to be made and this might lead to a reluctance to make these available to the domestic market until/unless the option is not deemed viable. Domestic supply may become seen as more desirable/feasible in the event of a relatively pessimistic LNG outlook.

Gas supply and transmission

Supply modelling outcomes

In the medium growth/medium LNG scenario, Queensland CSG dominates future supply from the commencement of LNG export in the period 2014 to 2015. By the middle of the next decade, Victoria conventional gas supply will increase with a modest, but increasing supply from New South Wales CSG.

When the high growth/high LNG scenario is compared with the medium growth/medium LNG scenario, the increase in gas supply required to meet the higher demand comes from Queensland CSG. However, when compared with the medium scenarios, the low growth/low LNG scenario shows a decrease in supply from all sources with the exception of Cooper Basin conventional gas.

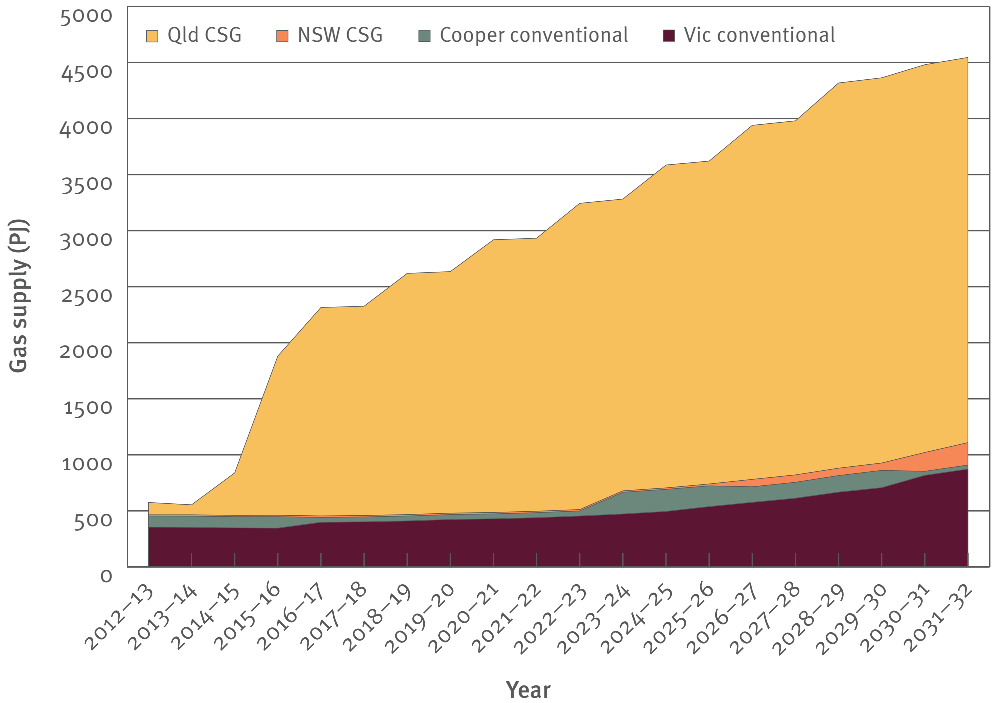


Figure 26 Gas supply by type for the medium growth/medium LNG scenario (PJ)

Source: IES (2012)

Transmission modelling outcomes

LNG is the dominant issue in the Queensland gas market moving forward. Given that dedicated gas pipelines will be developed for these projects, gas flow impacts on existing gas pipelines will be minimal with the exception of the SWQP/QSN, which has already been expanded.

The modelling indicates that stage 1 of the Queensland Hunter Gas Pipeline could enter the Queensland market in 2030–31, but due to the opportunity it presents to monetise gas in the Gunnedah Basin it may enter earlier. Also, due to the established reserves in the Clarence–Moreton Basin, the modelling indicates (in all scenarios) that the Lions Way Gas Pipeline would commence operation in the period 2023–24 to 2028–29.

Potential supply from the southern states

IES modelled the potential for gas supply from the southern states to support future Queensland demand. This showed that (using the cost of supply plus pipeline costs) the economic outcome was Queensland gas demand supplied by gas fields in Queensland and that physical transport of gas from Victoria was not likely to be economical.

Physical constraints and the cost of transport etc. present significant hurdles to wholesale sales of Victorian gas in Queensland. Gas transfers would be only be considered likely if supply costs in Victoria are substantially cheaper than Queensland CSG or if the gas price in Queensland is substantially higher than the southern states. On this basis, significant gas swaps over longer timeframes would require a price differential settlement, but some small gas swaps could potentially proceed on a net transfer basis.

Market conditions, issues and recommendations

Market conditions

- The Queensland gas market lacks liquidity with gas in short supply for new contracts both pre- and post-2015.
- This is contributing to a high level of uncertainty in the market, which is also impacted by the uncertainties of domestic and international LNG and future gas prices.
- Ramp-up gas, that previous modelling assumed would be a feature of the market prior to the commencement of LNG export, has not materialised due to a range of management techniques including gas swaps between LNG proponents, and storage and production delays resulting from floods.
- In the 12 months to June 2012, customers seeking a new domestic supply contract for gas post-2015 reported a continued lack of access to basic market information (forward prices, volumes available and potential delivery timeframes) for forward contracting. No customer seeking domestic supply of gas reported achieving a term sheet (binding or non-binding) for a large volume of gas. A small number of customers reported offers for small volumes of gas for short terms.
- A feature of market activity in the past 12 month has been the entrance of LNG proponents as customers of other producers. In contrast to customers seeking domestic supply of gas, LNG proponents have been able to access the required information and contract for gas.

Market issues

- Access to gas reserves for domestic contracting is particularly sensitive to the development of new LNG trains prior to 2020, and this sensitivity could continue if a significant number of trains continued to be developed post 2020:
  - For the current level of 6 committed LNG trains and a further 2 trains post-2020 (8 in total), the modelling of gas reserves and ownership found that there were available reserves throughout the 20-year study period and sufficient gas to supply all demand, including LNG trains. Under this scenario, gas would be expected to become available to the domestic market.
  - For the current level of 6 committed LNG trains and the construction of a further 2 trains prior to 2020 (8 in total), reserves level available for domestic market contracting would be highly sensitive to, and dependent upon, on planned or above planned reserves conversion and development rates—low reserves conversion rates and slow development could result in a continuation of the current tight market conditions or, in the worse case, a potential reserves shortfall.
  - Beyond the development of 8 LNG trains prior to 2020 (currently 6 committed plus 2 additional), reserves shortfalls would occur, with the level of shortfall proportional to the number of additional trains developed.
- Modelled gas prices fell in a wide range—$6 to $12/GJ depending on the submarket demand and oil prices. Similar to the 2011 GMR outcomes, regardless of demand, market expectation of future gas prices continues to remain at the higher end of the range.
- Implementation of the PGPLR cannot be supported based on current LNG projects that have reached FID. However, even when these developments reach production capacity and gas reserves might be assumed to be available in the future to the domestic market, there is the potential for stockpiling of reserves to retain the option of developing further LNG trains. The pace of development of LNG trains, in addition to the 6 under construction plus a further 2 trains, will be a key issue impacting whether future domestic gas market liquidity improves or declines further.

Recommendation

The Queensland Gas Market Advisor recommends that government consider the security of domestic gas supply and market liquidity in the planning and approval process for development of future new LNG trains.

- Major industrial customers in the domestic market are effectively unable to resolve future contracting requirements and business plans due to lack of access to future gas supply contracting information—in market terms, the market is unable to 'clear'.
- Balance has not been achieved between large gas demand for export supply and demand for domestic gas supply.
- Industry debate on the issue appears to have become captured by the option to reserve gas for domestic use (reservation) and the price impact for domestic gas customers as result of connection to the international LNG market.
- There are a range of potential options, ranging from regulatory intervention to market facilitation, that could encourage market participants to achieve balanced export/domestic market outcomes, and a wider, more informed debate is desirable.

The Gas Market Advisor cautions that if the next 12 months does not see the future domestic supply situation improve, there could be insufficient time for development, consideration, consultation and implementation of measures that could be implemented by government to address a domestic supply constraint in the period 2015 to 2020.

Recommendation

The Queensland Gas Market Advisor recommends that government undertake early work to develop and consider measures that could be implemented in a timely manner should the future domestic supply constraint continue.

List of shortened forms

1C	Sub-commercial contingent resources (low estimate)
2C	Sub-commercial contingent resources (best estimate)
3C	Sub-commercial contingent resources (high estimate)
1P	Proved reserves
2P	Proved and probable reserves
3P	Proved, probable and possible reserves
AEMO	Australian Energy Market Operator
AP&G	Australian Power & Gas
APLNG	Australia Pacific LNG
AUD	Australian dollar
bbl	United States dollars per barrel of oil
BG	British Gas Group
BTU	British thermal units
CGP	Carpentaria Gas Pipeline
CSG	Coal seam gas
EGP	Eastern Gas Pipeline
EIS	Environmental impact statement
ESOO	Electricity Statement of Opportunities (AEMO)
FID	Final investment decision
FOB	Free on board
GJ	Gigajoule
GLNG	Gladstone LNG
GMR	Gas Market Review
GPG	Gas power generation
GRAM	Gas Reserves Availability Model
GSA	Gas sales agreement
GSOO	Gas Statement of Opportunities (AEMO)
HoA	Heads of Agreement
IES	Intelligent Energy Systems
JCC	Japan Crude Cocktail/Japan Customs-cleared Crude
LNG	Liquefied natural gas
MAP	Moomba to Adelaide Pipeline
MoU	Memorandum of understanding
MSP	Moomba to Sydney Pipeline
mmbtu	Million British thermal units
MPa	Megapascal
MT	Megatonne
MTPA	Million tonnes per annum
NEM	National Electricity Market
NQGP	North Queensland Gas Pipeline
PetroChina	China National Petroleum Corporation
PGPLR	Prospective Gas Production Land Reserve
PJ	Petajoules
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
QSN	QSN Link Pipeline
RBP	Roma to Brisbane Pipeline
RLMS	Resource and Land Management Services
SCER	Standing Council on Energy and Resources
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
TJ/d	Terajoules per day
USD	United States dollar

References and further reading

AEMO, see Australian Energy Market Operator, <www.aemo.com.au>.

Australian Energy Market Operator, *Electricity statement of opportunities for the National Electricity Market 2011*, AEMO, available from <www.aemo.com.au>.

Australian Energy Market Operator, *Gas statement of opportunities for eastern and south eastern Australia 2011*, AEMO, Melbourne, available from <www.aemo.com.au>.

Australian Energy Market Operator, *Industry guide to the STTM 2011*, version 3.3, AEMO, available from <www.aemo.com.au>.

Australian Energy Market Operator, *Overview of the Short Term Trading Market 2011*, version 4.2, AEMO, available from <www.aemo.com.au>.

Australian Energy Market Operator, *Review of the operation and design of the Short Term Trading Market 2012*, AEMO, available from <www.aemo.com.au>.

Australian Energy Regulator, *State of the energy market 2011*, Australian Competition and Consumer Commission, Canberra, available from <www.accc.gov.au>.

BP, *BP energy outlook 2030*, BP, London, available from <www.bp.com>.

CIGI, *see* Centre for International Governance Innovation, <www.cigionline.org>.

DNRW, *Queensland's Petroleum: Exploration and Development Potential*, Brisbane, available from <www.mines.industry.qld.gov.au>.

EIA, *see* US Energy Information Administration, <www.eia.gov>.

ExxonMobil, *The outlook for energy: a view to 2040*, ExxonMobil, Irving, Texas, available from <www.exxonmobil.com>.

Geoscience Australia, *Oil and gas resources Australia 2010*, available from <www.ga.gov.au>.

Geoscience Australia & ABARE 2010, *Australian energy resource assessment*, Canberra, Department of Resources, Energy and Tourism, available from <www.abare.gov.au>.

International Energy Agency, *World energy outlook 2011*, OECD/IEA, Paris, available from <www.worldenergyoutlook.org>.

Ministerial Council on Energy, *Statement on principles for gas market development 2004*, MCE, Canberra, available from <www.ret.gov.au>.

SKM MMA, *Gas market modelling for the Queensland 2011 Gas Market Review*, available from <www.deedi.qld.gov.au>.

Standing Council on Energy and Resources communiques available from <www.scer.gov.au>.

US Energy Information Administration, *Annual energy outlook 2011*, EIA, Washington DC, available from <www.eia.gov>.