Department of **Employment, Economic Development and Innovation**

# 2011 Gas Market Review
# Queensland

Queensland Government

CS0446 08/11

# Contents

# Preface

I am pleased to present the second 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 2011 GMR builds on the platform of the first GMR in 2010 to provide a comprehensive picture and detailed analysis of the current state of the Queensland gas market, together with forecasts for future industry growth and participants' needs.

The GMR is still in its formative years and evolving, so there are changes from last year's format. These changes are designed to provide an improved market context; achieve better separation of the discussion on demand growth from expected infrastructure impacts; capture the significant industry and market progress made in the past 12 months; and improve market communication of these changes.

This year's review also has a particular focus on identifying the timing of volume growth and existing load coming to market and developing the modelling horizons required to identify potential future supply shortfalls. This will assist discussion and consideration of Prospective Gas Production Land Reserve issues.

The 2011 GMR consists of a general overview and background; a summary and update on relevant government legislation, regulation and initiatives; a market update and discussion of competition issues; a response to issues raised by the 2010 GMR; and a supply–demand review that includes the consultant's modelling report and summary findings.

There have been high levels of engagement with industry participants and comprehensive public consultation in developing the 2011 GMR. Our aim was to capture all relevant views and ensure transparency and industry consensus on the outcomes. Further feedback is sought from stakeholders in order to refine the modelling and analysis and settle the scope of the GMR.

I look forward to your ongoing contribution to the issues surrounding the development of the Queensland gas market.

Kay Gardiner
Queensland Gas Commissioner

# Acknowledgments

The Queensland Annual Gas Market Review is entirely dependent on the active engagement and contributions of gas market participants. I gratefully acknowledge the many organisations within the gas industry who voluntarily and enthusiastically participated in the review process and supplied information and views to help shape the preparation of the 2011 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.

# Executive summary

The annual Gas Market Review (GMR) is an initiative of the Queensland Government. It informs government decision-making regarding the need to develop Prospective Gas Production Land Reserve tenure. It also considers the development of a more competitive and transparent Queensland gas market.

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

## Background

The Queensland annual GMR deals exclusively with natural gas—referred to simply as 'gas'. The history of gas exploration and production in Queensland shows us that the pattern of development has been cyclical—lengthy periods of incremental development have been interspersed with periods of major investment, projects and growth. In 2011, we are in one such growth period, with the development of a coal seam gas (CSG) to liquefied natural gas (LNG) export industry.

By 2007–08, it had become evident that the availability and potential of gas reserves in Queensland had outstripped existing and potential demand in the greater east coast Australian gas market. Queensland CSG producers then looked to access international gas markets via LNG. LNG development projects began to appear on drawing boards from 2007. The first CSG-based LNG project was announced in May 2007 and since that time a further nine have followed, of which four have achieved 'significant project' status and three have all the necessary approvals for the projects to proceed.

## Modelling scenarios

The 2011 GMR focuses on developing the appropriate modelling horizons to identify major potential demand growth or supply shortfalls. In particular, this means modelling into the immediate years to 2015–17 when LNG exports are scheduled to commence.

Economic assumptions provide a framework for assessing impacts on the broad marketplace and are sufficient when modelling for the medium and long term, as economic influences have the time to drive infrastructure and market responses. Three economic scenarios were developed and are referred to as High, Medium and Low because they largely correlate with high, medium and low economic parameters, although they are not the only parameters used.

The Queensland Gas Commissioner has noted that infrastructure and market responses have implementation time frames that cannot always be met in the short term. The period to 2015 is the time frame during which LNG export projects will be under development and economic responses may not be able to mitigate technical and operational impacts. To model the impact of this issue, a Technical/Operational Impacts scenario was developed. This scenario takes into account the time frames required to construct transmission infrastructure to link additional gas resources to the existing Queensland

transmission network. Where no start has been made, it is assumed infrastructure and reserves cannot be developed in the time frame.

In 2010 and 2011, Queensland experienced major flood events, which have impacted producers' appraisal programs and subsequent reserves development; it seems unlikely that the reserves growth achieved in 2007–08 and 2008–09 will be achieved in 2010–11. There could be additional impacts on appraisals in the coming years if recent weather patterns signal a return to heavy wet seasons.

In order to assess the potential impact of weather and floods on reserves growth, the Technical/Operational Impacts scenario assumes that proved and probable (2P) reserves growth is restricted to 50 per cent of maximum achievable levels in 2010–11 and 2011–12.

## Gas demand

Consultant group SKM MMA estimates the 2011 eastern Australian demand at 704 PJ/year. Demand for gas within eastern Australia is considered in two segments: domestic and LNG export. Domestic demand is further broken down into customer segments:

- utility—gas for customers who are supplied principally from distribution mains
- large industrial—customers consuming significant quantities who are supplied principally from transmission mains
- gas power generation (GPG)—gas for power generation, including large cogeneration projects.

The outcomes of modelling for Queensland markets are:

- *Brisbane*: Projected demand of the Brisbane utility plus large industrial loads over the period 2010 to 2029 is forecast to grow at a slow but steady rate of between 1.2 per cent and 1.8 per cent; the results are very similar for all modelled scenarios.
- *Gladstone*: All scenarios show significant lumpy increases over the period, related largely to cogeneration and potential major user expansions. The Medium and Low scenarios are similar. Projected demand over the period 2010 to 2030 is forecast to grow in a range between 3.8 per cent and 8.4 per cent.
- *Mount Isa*: The project to connect the Mount Isa electricity market to the National Electricity Market (NEM) via cable from either central or northern Queensland would impact GSG flows significantly. The project is included in the High scenario, reducing gas demand by about 20 PJ/year and resulting in a High scenario growth outcome that is lower than either the Low or Medium scenarios.
- *Townsville*: Townsville is a GPG market for the Townsville Power Station and has large industrial load for major customers Queensland Nickel and Copper Refineries Limited. For Townsville, the Low scenario is largely 'business as usual'.
- *Gas power generation*: Aggregate GPG modelling outcomes show a doubling of load from 200 PJ/year to 400 PJ/year between 2012 and 2014, mostly in Victoria due to the assumed retirement of brown coal generating plant.

When Queensland domestic gas demand is aggregated with demand from New South Wales, Victoria, South Australia and Tasmania, growth is strong in all scenarios. Demand outcomes by 2030 are in the range of 1200 PJ/year (41% increase) to 1850 PJ/year (62% increase). Cumulatively, the requirement for contracts for new loads exceeds the requirement for existing loads in the High and Medium scenarios and the requirements are approximately equal in the Low scenario. In Queensland, many gas sales agreements (GSAs) reach term in the period 2015 to 2020 and the requirement for contracts for new loads exceeds the requirement for existing loads in all three scenarios, as shown in Figure E1.

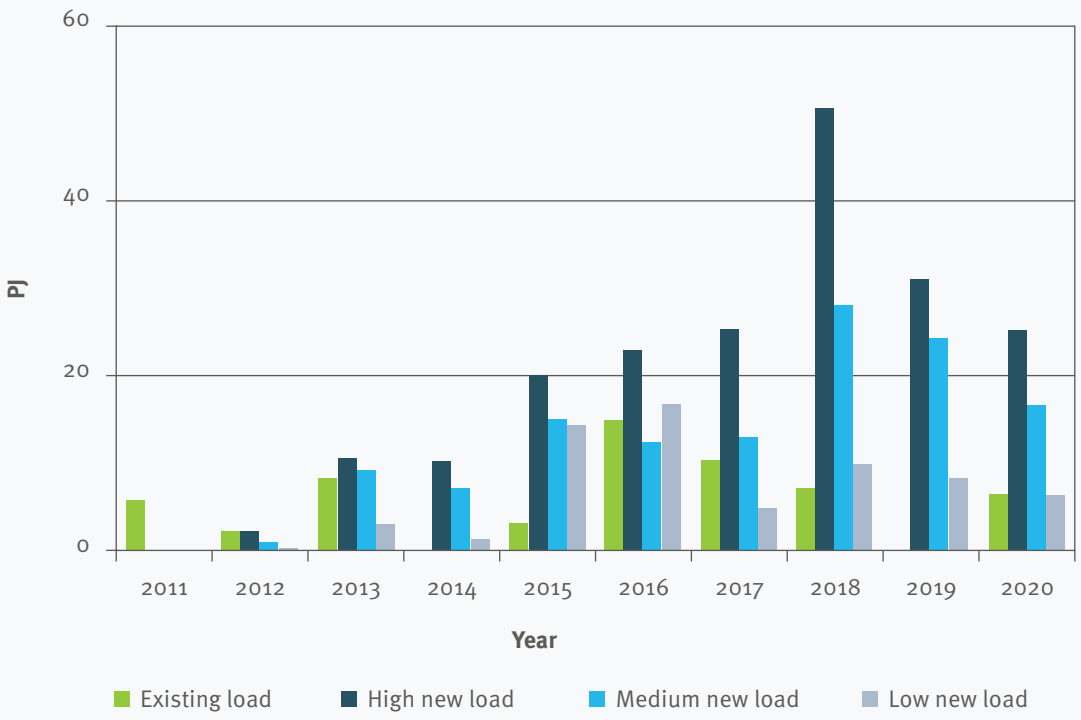



***Figure E1*** *Annual new contract requirements for existing and new loads, Queensland, 2011–2020 (PJ/year)*

*Source: SKM MMA (2011)*

## Gas reserves

Conventional 2P 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 in 2008. For the eastern Australian gas market, total 2P reserves are estimated at 43 650 PJ. The contingent and prospective gas resource is estimated at 202 991 PJ.

The LNG projects will use substantial volumes of gas—approximately 220 PJ/year for each 3.5-Mtpa train. The committed projects therefore require approximately 17 600 PJ plus further margins for risk management. Additional trains or projects will add to this requirement. This and existing domestic GSA requirements can be translated directly into requirements for gas reserves.

Physical shortfalls do not occur in any of the modelled economic scenarios. The economic scenario modelling highlights that the aggregate reserves requirements for LNG export and domestic demand in the High economic scenario, with maximum reserves development, maintain a 2P reserve margin of approximately 30 000 PJ until 2020. If the High economic scenario result has reserves growth reduced in line with the Technical/Operational Impacts scenario, the reserves available remain at approximately 10 000 PJ from 2011 to 2017.

The requirements in the Medium and Low economic scenarios can also be met readily with much larger margins extending into the long term, to the extent that reserves development at the maximum rate is unlikely to be required.

The picture is somewhat different in the Technical/Operational Impacts scenario, which focuses only on the period to 2015–2016 and does not consider gas reserves and potential reserves that cannot be accessed due to lack of infrastructure from now until 2015. Queensland domestic reserves requirements in this scenario are:

- in 2011, 622 PJ for domestic contracts and 1139 PJ for third-party LNG contracts (reflecting a projected deficit owing to the impact of floods on reserves development)
- in 2012, 379 PJ for domestic contracts and 233 PJ for third-party LNG contracts.

In this outcome, total reserves available in 2011 are 1751 PJ and the total reserves requirements are 1761 PJ, leaving a small shortfall of 10 PJ. In 2012, the only reserves available would be 197 PJ due to reserves increases, assumed to be 97 PJ in the Cooper Basin and 100 PJ for the second-tier Surat–Bowen producers, against 612 PJ of reserves requirements. This leaves a substantial shortfall of 415 PJ or 425 PJ if the 2011 shortfall is accumulated.

This scenario outcome demonstrates that an inability to supply gas for domestic GSAs is possible under circumstances that are plausible and aligns with reports of delayed appraisal programs. Even if the constraint of weather and flood is assumed to apply only in 2010–11, the scenario demonstrates that access to reserves for domestic contracting would be tight.

During consultation for the 2011 GMR, customers and potential customers have 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. This aligns with the Technical/Operational Impacts scenario outcome.

The Queensland Gas Commissioner is concerned that, unless domestic appraisal plans are in place or shortly put in place, available gas reserves may not be sufficient to underpin execution of new domestic GSAs. For efficient operation, the Queensland gas market requires clarity on the activities underway to develop reserves for domestic market use post-2015.

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 are supported by the modelling and analysis undertaken for the GMR. This indicates a tight reserves position as LNG projects prove up reserves to underpin LNG projects.

### *Recommendation*

The Queensland Gas Commissioner recommends 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.

## Gas supply

An analysis of the projected aggregate gas supply outcomes for eastern Australia (including LNG export requirements) for the three economic scenarios shows that the key aspects are:

- overall dominance of Queensland CSG production (LNG exports)
- strong growth in New South Wales CSG from the Gunnedah Basin, particularly in the High scenario
- a modest resurgence in Cooper Basin production owing to the sale of gas to Gladstone LNG
- modest growth in Gippsland Basin production
- declining production in the Otway and Bass basins owing to declining reserves
- in the High scenario, an overall decline in production at the end of the period owing to the rise in prices at that time.

The Medium scenario outcome is shown in Figure E2.

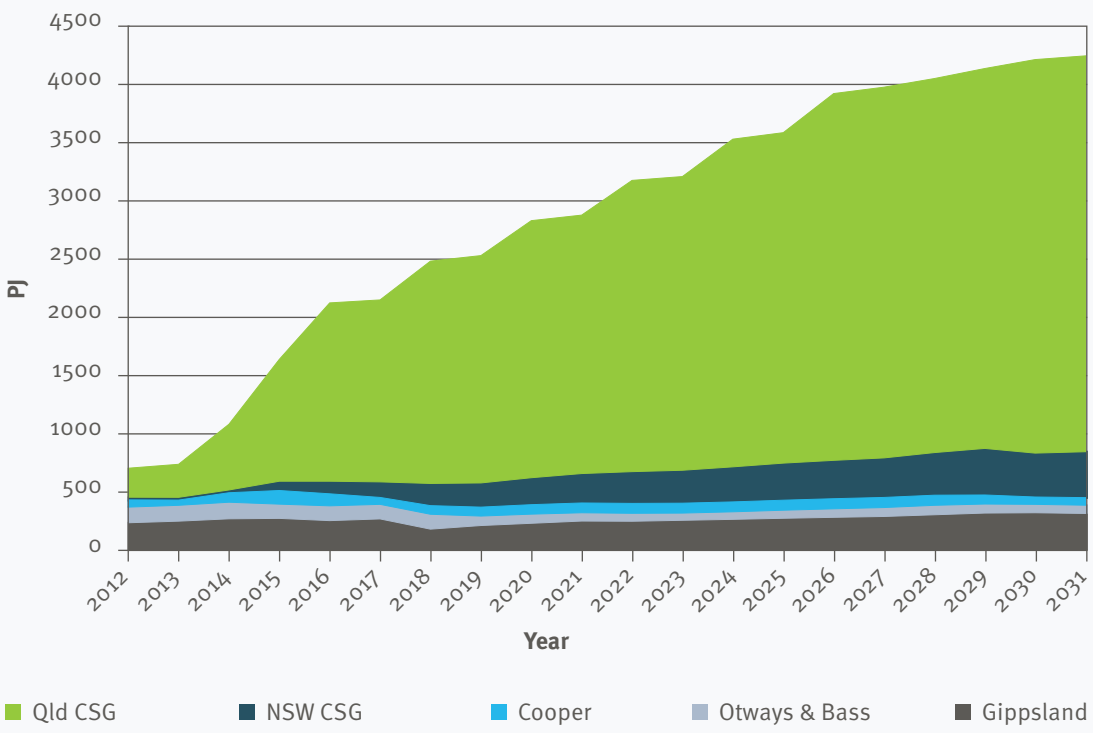



***Figure E2*** *Projected supply eastern Australia (domestic plus exports), 2012–2031, Medium scenario (PJ/year)*

*Source: SKM MMA (2011)*

## Domestic gas pricing

Projected gas pricing in all Queensland markets is very sensitive to the scenario assumptions, but the scenarios have similar outcomes (Figure E3). Across Queensland in aggregate:

- In the High scenario, new contract prices are expected to rise substantially from 2013, to over $8/GJ in most markets. This level is maintained until growth in LNG stops in the mid-2020s, at which point prices temporarily fall by $1–2/GJ, but then rise back to former levels owing to reserves depletion. The High scenario most closely replicates projections of LNG netback prices with oil price indexation.
- In the Medium scenario, new contract prices are expected to rise initially to approximately $6/GJ but then ease to $5/GJ as reserves growth outpaces growth in exports after 2018.
- In the Low scenario, new contract prices are expected to rise slightly up to 2016 but are expected to be more restrained.
- Ramp-up gas is included in initial contracts and is reflected in the declining average price in Queensland up to 2014.

Current market price expectations and behaviour indicate the High scenario is likely to eventuate. The price rises in this year's High scenario are higher than in the High scenario modelled for the 2010 GMR, largely because of the higher LNG projections. The price rises in the Medium and Low scenarios are very similar to those in the 2010 GMR.

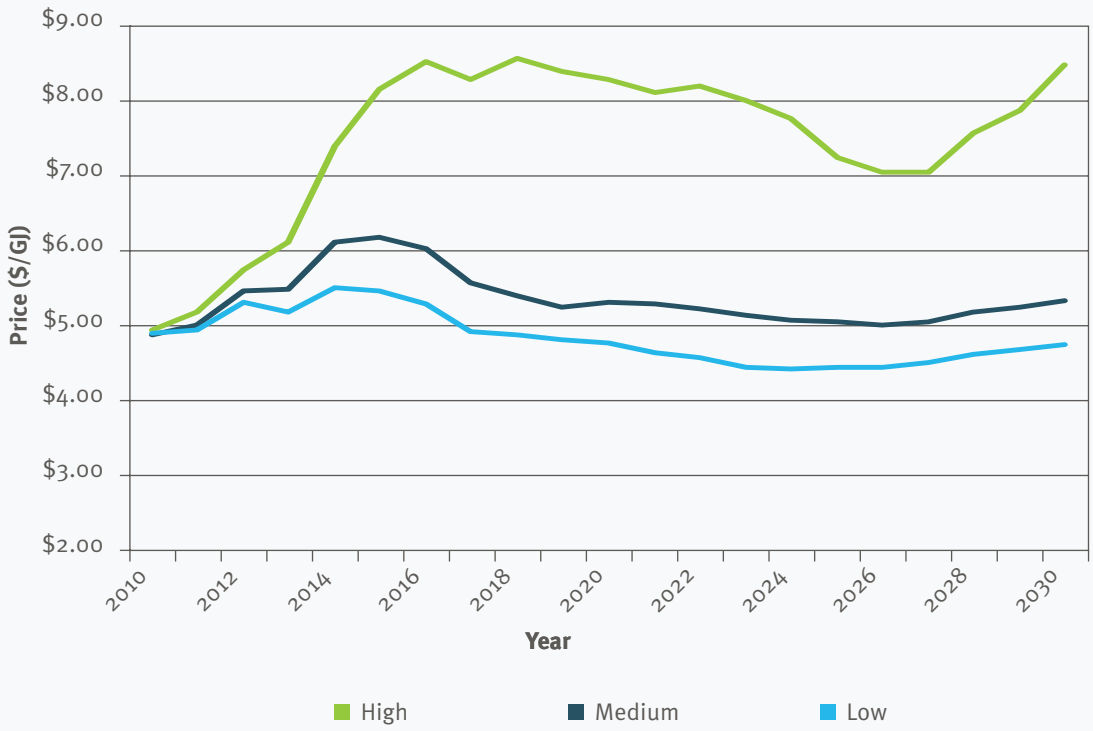



***Figure E3*** *New contract prices, Queensland aggregate, 2010–2030, all scenarios ($/GJ, $2011 real)*

*Source: SKM MMA (2011)*

New contract prices in southern states are projected to rise slightly later than Queensland prices. This is attributed to a more limited requirement for new contracts, especially in Victoria until 2018.

## Market overview and issues identified

### Gas transmission pipelines

There are four major interconnected gas transmission pipelines in Queensland. These are the Roma to Brisbane Pipeline (RBP), the Carpentaria Gas Pipeline (CGP), the Queensland Gas Pipeline (QGP) and the South West Queensland Pipeline (SWQP). The QSN Link (QSN) interconnects the SWQP with the Moomba to Sydney and Moomba to Adelaide pipelines.

Another major pipeline, the North Queensland Gas Pipeline (NQGP), runs from Moranbah to Townsville and is currently unconstrained with opportunities for future pipeline expansion through the addition of compression. Modelling shows that even in the High scenario, additional capacity would not be required until 2023.

Modelling of the interconnected pipelines and the QSN suggests that they will face nearly static load factors over the next 10 years and that pipeline expansion in proportion to annual demand, in line with current load factors, will be sufficient to meet peak domestic market requirements (Figure E4).


***Figure E4*** *Actual and estimated throughput of major Queensland pipelines, 2009 and 2010 (PJ/year)*

*Source: SKM MMA (2011)*

Note: RBP = Roma to Brisbane Pipeline; CGP = Carpentaria Gas Pipeline; QGP = Queensland Gas Pipeline; SWQP = South West Queensland Pipeline; QSN = QSN Link Pipeline

The initial capacity of the RBP, QGP, SWQP and CGP has been expanded, with more expansions either underway or planned. These are being undertaken in a timely manner. With five new pipelines under development to support growth of the LNG industry, investment in pipelines and capacity expansions puts Queensland in a very strong position.

Pipeline owner-operators have expressed a desire to allow a reasonable volume for further incremental growth when undertaking a major capacity expansion. Customers also seek this outcome. It is acknowledged that many factors play into successful investment in pipeline capacity expansions. Nevertheless, there appears to be the potential for a category of customer to be excluded from timely purchase of pipeline capacity due to their volume requirements. To address this issue, a review of this section of the national legislation would be required.

Pipeline owner-operators and customers have expressed concern that national legislative provisions discourage investment in uncontracted capacity when pipeline expansions are being undertaken.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government act through the appropriate jurisdictional forum/s to raise the issue of incremental pipeline capacity expansion for review.

## Gas distribution networks

There are approximately 165 000 customers on Queensland gas distribution networks; about 95 per cent of these customers are residential users. Average residential consumption in Queensland is currently approximately 9–10 GJ/year, down from the 11–12 GJ/year of earlier years. Networks continue to increase overall customer connections, while overall gas use is declining. This reflects the impact of competition from other fuel sources and improved appliance and operational efficiencies. In this environment it will be difficult to grow gas use in the residential sector.

In the commercial and small industrial sector, volume is expected to grow slowly but steadily at 1.1 per cent annually due to increasing business focus on efficient energy use. Customer numbers are expected to grow at less than 1 per cent per year. The sector also faces fuel competition, including from coal, which continues to be used as a fuel by some customers with access to gas. Coal use has dropped over the years, but it is understood that use still equates to several petajoules per year of gas use. Little work has been done in this area, but it offers some potential to increase gas consumption on the distribution networks and improve utilisation of the infrastructure.

The use of coal as a fuel in areas served by gas distribution networks has dropped over the years, but coal remains a competitor to increased gas uptake in the commercial gas customer sector.

### *Recommendation*

The Queensland Gas Commissioner recommends that 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.

## Short Term Trading Market

The Sydney, Adelaide and Brisbane gas markets and the design of the Short Term Trading Market (STTM) reflect the interaction of retailers and users operating on, or in close proximity to, the capital city distribution networks; this is demand based.

Once the two committed LNG projects (four trains) are fully operational after 2015–16, the annual volume of gas required by the projects will equal the current eastern Australian gas market consumption. Demand in Queensland will exceed 1000 PJ/year.

Balancing a large gas market and gas supplies to large LNG plants will require trading among LNG participants and other gas producers and users. This trading should be visible to the market and supported by market structures.

The growth in gas production centred in the Surat Basin region around Wallumbilla—where three major gas transmission pipelines interconnect and four new pipelines are planned—provides a timely opportunity in the period to 2015 to design, develop and implement a supply-based trading market.

A supply-based trading market has the potential to substantially improve market liquidity and transparency and offers a timely opportunity to work with other jurisdictions to underpin investment in transmission interconnections and lever the benefits of a supply STTM.

During consultation for the 2011 GMR, stakeholders indicated strong support for the development and implementation of a supply-based trading market. Given that LNG production will start from 2015, it would be desirable for the supply-based trading market to be operational by 2015 at the latest.

Stakeholders have indicated strong support for the development of a supply-based trading market centred in the Surat Basin around Wallumbilla (Roma) that would support market trading of produced gas and commencement of LNG production from 2015.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government continue to work through the Standing Council for Energy and Resources (SCER), the gas market reform process and with stakeholders to settle a design for a supply-based trading market for implementation by 2015.

The market developments in Queensland and a potential supply-based trading market offer a timely opportunity to work with other jurisdictions to underpin investment in transmission pipeline interconnections and lever the benefits of a supply-based trading market.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government consider opportunities to work with the New South Wales Government and industry to facilitate the development of improved gas infrastructure interconnections and lever the market benefits of a supply-based trading market.

## 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. Most dedicated gas (non LNG) storage facilities are developed from depleted gas or oil fields, but natural aquifers and salt caverns are also used.

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. In an evolving and rapidly growing and maturing gas market such as Queensland's, the development of dedicated commercial natural gas storage facilities can provide flexibility for both producers and customers. Gas storage can also support competitive market trading and enhance security of supply for export and domestic customers, including gas-fired generation.

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.

### *Recommendation*

The Queensland Gas Commissioner recommends 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.

# Introduction

The annual Gas Market Review (GMR) is an initiative of the Queensland Government. It informs government decision-making regarding the need to develop Prospective Gas Production Land Reserve tenure. The GMR also:

- identifies and analyses key issues affecting the effective management of resources
- considers the development of a more competitive and transparent Queensland gas market
- aims to help stakeholders and government keep abreast of the increasing complexities of the Queensland market gas and its links to interstate and international markets.

The annual GMR provides an opportunity for improved industry communication about the gas industry in Queensland and aims to grow stakeholder knowledge and understanding of the current state of the gas market and the issues impacting different market sectors.

The outcomes of the GMR inform government and the Queensland gas market about identified constraints on gas supply availability, gas market development and security of supply within the relative context of the broader eastern Australian gas market.

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

The 2011 GMR is the second review. The initial GMR took place in 2010.

## Consultation for the 2011 GMR

A primary objective for the Queensland Gas Commissioner 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 2011, together with issues likely to impact the future of the gas market.

In undertaking the 2011 GMR:

- The Stakeholder Reference Group was formed.
- Two stakeholder forums were held.
- The draft modelling and analysis work was put out to consultation through the Stakeholder Reference Group.
- The Queensland Gas Commissioner engaged in 31 one-on-one meetings with stakeholders.
- The review draft was released for full 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.

Consultation has provided an excellent understanding of issues faced by stakeholders and of current gas market directions. 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 2011 GMR.

## Prospective Gas Production Land Reserve policy

In November 2009, the Queensland Government announced a range of measures to enhance competition and promote transparency in the state's gas market in view of the emerging liquefied natural gas (LNG) export industry and the expected growth for this sector. The initiatives included the Prospective Gas Production Land Reserve (PGPLR) policy. The PGPLR aims to ensure future security of supply for domestic gas users in light of the international demand for gas. In particular, large industrial users and electricity generators must have access to large volumes of gas to underpin current operations and support future growth.

The *Gas Security Amendment Act 2011* received assent on 19 May 2011. The Act delivers the framework to implement the PGPLR policy, if domestic markets become supply constrained. The PGPLR provides the ability to condition future exploration tenure releases to ensure that any gas produced from a subsequent petroleum lease over the area can only be consumed within the Australian gas market.

The decision to impose PGPLR conditions will be made by government where supported by outcomes of the annual GMR process. It is assumed that grant of PGPLR land needs to precede a forecast production shortfall by up to seven years and reserves shortfalls (for contracting) by up to three years. The GMR considers and models issues such as:

- gas market supply
- demand and price variations for prescribed scenarios and time frames
- sensitivity on certain variables
- reserves and production
- transportation constraints
- demand requirements
- regulatory constraints
- drivers affecting gas prices
- likely impact of constraints and drivers on future gas prices and investment in the gas market.

## Focus of the 2011 GMR

The 2011 GMR focuses on developing the appropriate modelling horizons to identify major potential demand growth or supply shortfalls. In particular, this means modelling into the immediate years to 2015 to 2017 when LNG exports are scheduled to start. This period is important as it reflects the general seven-year time frame within which reserves can be developed and available for contracting by customers—two to three years of appraisal and reserves declaration, followed by three to four years to develop production capability (assuming that the reserves are contracted soon after they are declared due to strong demand).

In considering this time frame, the modelling and analysis conducted for the GMR covers the following.

*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 and final investment decision (FID) announcements
- 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 coal seam gas in Queensland) and factors that may affect it
- Factors 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

# Gas and its uses

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. It is frequently categorised as 'conventional' or 'unconventional' when exploring or producing.

**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.

**Unconventional gas** is tight gas, shale gas or coal seam gas.

- **Tight gas** is gas held tightly in low permeability conventional gas reservoirs.
- **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) and is the most common sedimentary rock found worldwide.
- **Coal seam gas** (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.

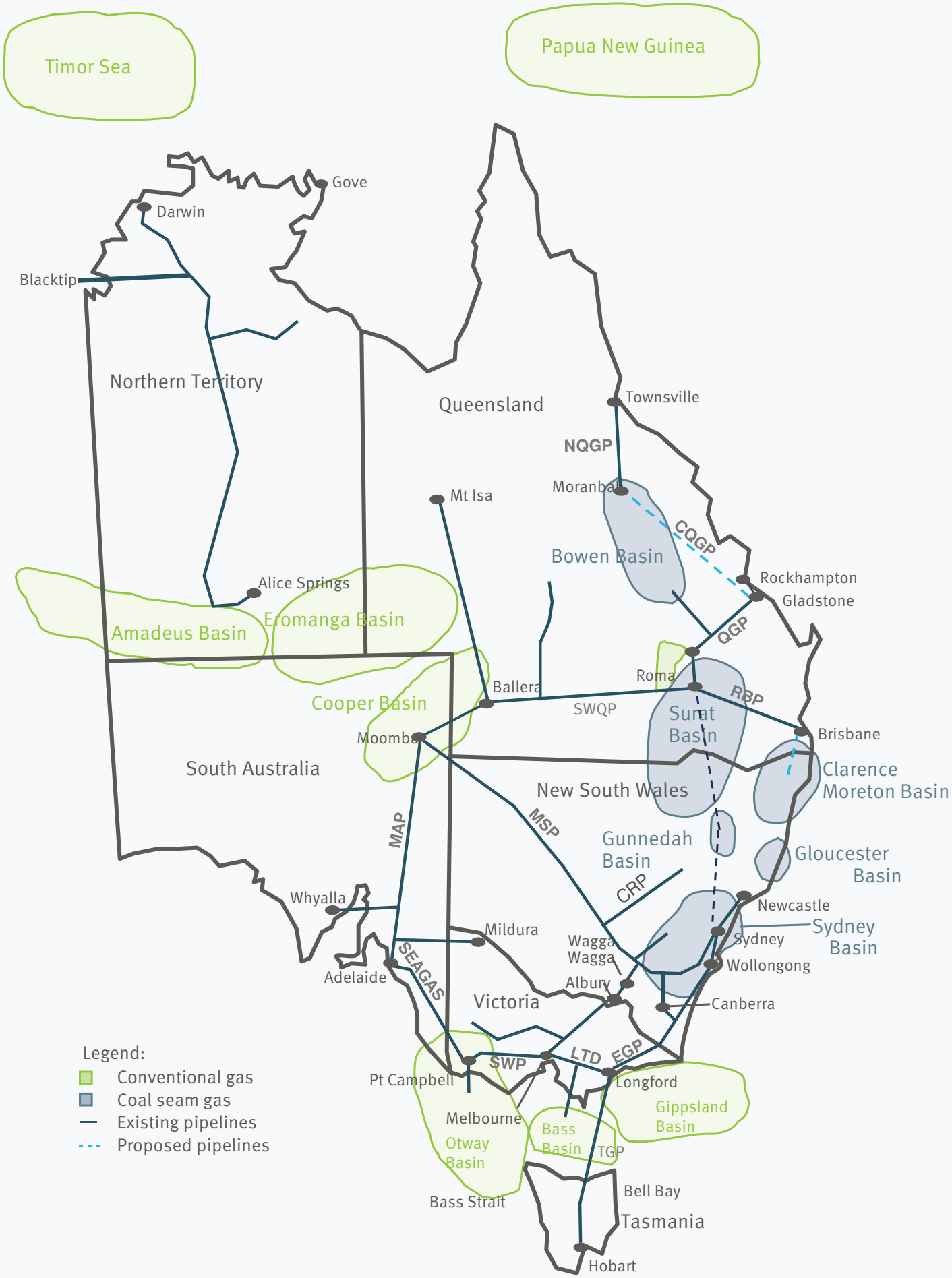
## Gas uses

The uses of gas are many and varied. Gas is used in Queensland as a residential fuel primarily for water heating but also to fuel stoves, ovens and clothes dryers. Gas is also used as an ingredient to make fertilisers, antifreezes, plastics, pharmaceuticals and fabrics and to manufacture a wide range of chemicals such as ammonia and methanol. Many manufacturing processes require heat to melt, dry, bake or glaze a product. Gas is used as a heat source in making glass, steel, cement, bricks, ceramics, tile, paper, food products and many other commodities. Gas is also used for industrial incineration and for cremation.

Of the three fossil fuels used for electricity power generation—coal, oil and gas—gas emits the least carbon dioxide per unit of energy produced. In Queensland, gas is used to generate electricity; over 2000 megawatts of installed gas-fired generation capacity supplies about 10 per cent of Queensland's total electricity demand.

Gas can also be used as a vehicle fuel, when it is known as compressed natural gas (CNG). This type of gas has significant advantages over gasoline and diesel because CNG vehicles emit 60–90 per cent less pollutants and 30–40 per cent less greenhouse gases. Brisbane City Council buses use CNG as a fuel.

Origin's 635 MW Darling Downs Power Station is the country's largest combined cycle gas-fired power station. Photo courtesy of Origin Energy.




Eastern Australia gas fields and pipelines
Source: SKM MMA (2011)

# Background

## History of gas in Queensland

Gas is not new in Queensland. In fact, Queensland has the longest gas history in Australia and has led the way on many fronts.

Queensland was the site of the first:

- gas discovery in Australia
- reticulation of natural gas
- commercial gas project
- major gas pipeline
- interstate gas sale
- capital city (Brisbane) to be supplied with reticulated natural gas
- producing CSG well
- development of CSG resources
- commercial CSG to LNG export projects.

The history of gas exploration and production in Queensland shows us that the pattern of development has been cyclical, with the state undergoing lengthy periods of incremental development interspersed with periods of major investment, projects and growth. In 2011, we are in one such growth period with the development of a CSG to LNG export industry.

### The early years

The first gas used in Queensland for industrial and residential use was a manufactured coal gas mixture of methane and other gases usually referred to as 'town gas'. In 1863, development of a gasworks on the Brisbane River at Teneriffe was under construction and in November 1865 town gas was first supplied to Brisbane business customers.

Town gas was reticulated and used for street lighting, heating, cooking and industrial use—many of the same uses as today.

Gas was first discovered in Australia by accident in 1899 at Roma when workers were drilling for water for the local hospital. This was a common occurrence in the early days of agricultural water drilling in Queensland, with drillers sometimes encountering gas and small quantities of oil mixed with the water. It is not known if this gas came from small conventional plays or coal seams as both are found around Roma.

In 1906, gas was connected for street lighting in Roma and lasted 10 days before the flow stopped. Nevertheless, it represents the first reticulation of gas in Australia.

## Conventional gas

There was intermittent gas exploration activity from the early 1900s onwards, but it was not until the early 1950s that serious gas exploration started in Queensland. For the next 10 years, exploring and proving of natural gas deposits was undertaken around north-west Roma and Gilmore in Central Queensland. These gas finds were from conventional gas plays.

By 1961, sustained gas production was sufficient to supply a commercial customer and the old Roma Power Station was converted to a gas-fired generator, becoming Australia's first commercial gas project.

With increasing gas production capability in Roma and a growing capital city in Brisbane to the west, the project to develop a 435 km gas pipeline to take gas from Wallumbilla (30 km east of Roma) into Brisbane started. The Roma to Brisbane (RBP) gas pipeline was officially opened on 17 March 1969 and was the first major natural gas pipeline in Australia.

With the opening of the RBP, Brisbane became the first capital city in Australia to have a supply of natural gas for commercial and domestic use and the first to have a natural gas distribution network. The Roma region supplied Brisbane through the 1970s and 1980s, but by the early 1990s it became obvious that the region's conventional gas supplies were declining.

In the late 1980s and early 1990s, the Ballera conventional gas field west of Roma in south-west Queensland was being developed. The first agreement in Australia to sell natural gas across state borders was completed in 1991, allowing the sale of gas from south-west Queensland to South Australian customers. In 1992, the first phase of the project was completed with the construction of the 180 km raw gas pipeline linking Ballera to the Moomba gas plant in South Australia. In 1994, the supply of gas from south-west Queensland to South Australia commenced.

The South-West Queensland Gas Project was developed to transport gas from Ballera to Brisbane to replace declining Roma region gas supplies. During 1995, major Brisbane customers Incitec, Allgas Energy and the Gas Corporation of Queensland agreed to purchase gas from south-west Queensland. These agreements underpinned the construction of a gas transmission pipeline to link the Ballera gas field and processing plant with the RBP at Wallumbilla.

The South West Queensland Pipeline (SWQP) was constructed in 1996; by 1997 gas from south-west Queensland was being supplied to Brisbane. Also in 1997, with long-term gas supply for Brisbane now secure, the town gas plant was completely decommissioned after 132 years of operation.

The Queensland gas market grew steadily, if unspectacularly, through to the 1990s. Growth was underpinned by conventional gas reserves that remained relatively static from the 1980s.

## Coal seam gas

Queensland has extensive coal reserves and it was recognised in the 1970s that there was the potential for these coal resources to contain large volumes of CSG. However, exploration for CSG during the late 1980s and 1990s was largely disappointing. Using techniques and technology imported from the United States, explorers spent hundreds of millions of dollars drilling for CSG in Queensland with little commercial success. The drilling techniques proved to be non-transferable, despite the geological similarities between the Queensland and US coalfields.

CSG exploration in the 1980s and 1990s was largely centred in the Bowen Basin in central Queensland. In the late 1990s, discoveries and later production from fields near Moura, at Fairview and Spring Gully near Injune, and Peat and Scotia near Wandoan demonstrated that large volumes of CSG could be produced from the Bowen Basin.

The first producing CSG well in Australia started production in 1988 from the Pleasant Hills gas field near Roma. Santos, the well owner, reports the well continues to produce CSG. It was not until 1996 that drilling and production techniques improved to the extent that CSG could support a commercial operation. The first commercial CSG operation started with a methane drainage project at the Moura coal mine. Also in 1996, CSG from mine operations was used to fuel on-site, small-scale gas-fired power stations. In the late 1990s, discoveries and production from fields near Moura, Injune and Wandoan demonstrated that large volumes of CSG could be produced. Since then, rapid growth of demand has been underpinned by the development of CSG reserves. The overwhelming majority of Australia's current CSG reserves are found in Queensland (more than 92%).

The biggest incentive to invest in gas exploration is an available market. In May 2000, the Queensland Government released an energy policy that included an initiative to mandate that 13 per cent of the state's electricity be sourced from gas from 1 January 2005. In February 2002, it was announced that CSG would fuel the converted Townsville Power Station. These initiatives underpinned rapid growth in demand (Figure 1), as well as growth in exploration and production of CSG.

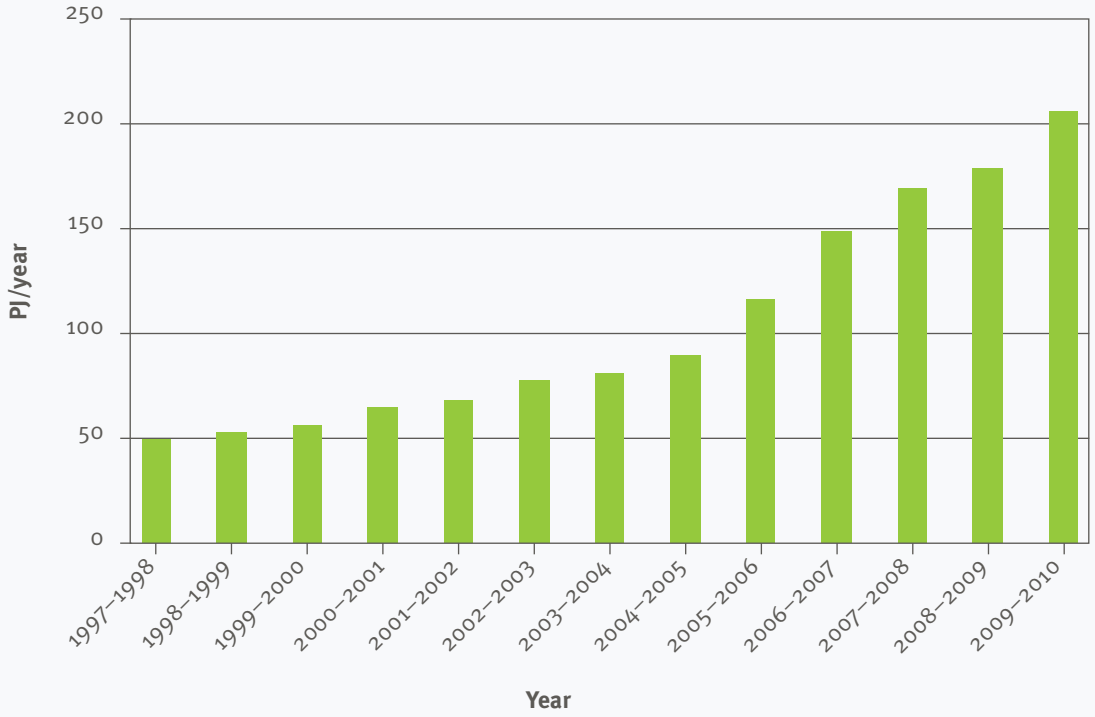



*Figure 1 Queensland gas demand, 1997–2010 (PJ/year)*

# CSG production

CSG has been extracted in the US for close to 30 years. This has made the US the world leader in CSG production, with 1746 PJ produced in 2008 (CIGI 2009).

CSG is produced by drilling a well into a coal seam; gas is then released by pumping out water to reduce water pressure. If the gas does not flow in sufficient volumes just by releasing water pressure, the coal seam is hydraulically fractured.

Hydraulic fracturing is achieved by pumping large volumes of water and sand at high pressure down the well into the coal seam. This causes the seam to fracture for distances of up to 400 m from the well. The sand carried in the water is deposited in the fractures to prevent them closing when pumping pressure ceases. The gas then moves through the sand-filled fractures to the well.

A commercial CSG production operation needs the right combination of:

- coal thickness
- gas content
- permeability
- drilling costs (number of wells, seam depth and coal type)
- volume of dewatering required to allow gas flow
- proximity to infrastructure.

In 2001, for the first time, the number of CSG wells drilled in a year surpassed the total number of conventional petroleum (oil and gas) wells drilled. Figure 2 shows the rapid growth of CSG production from the Bowen and Surat basins.

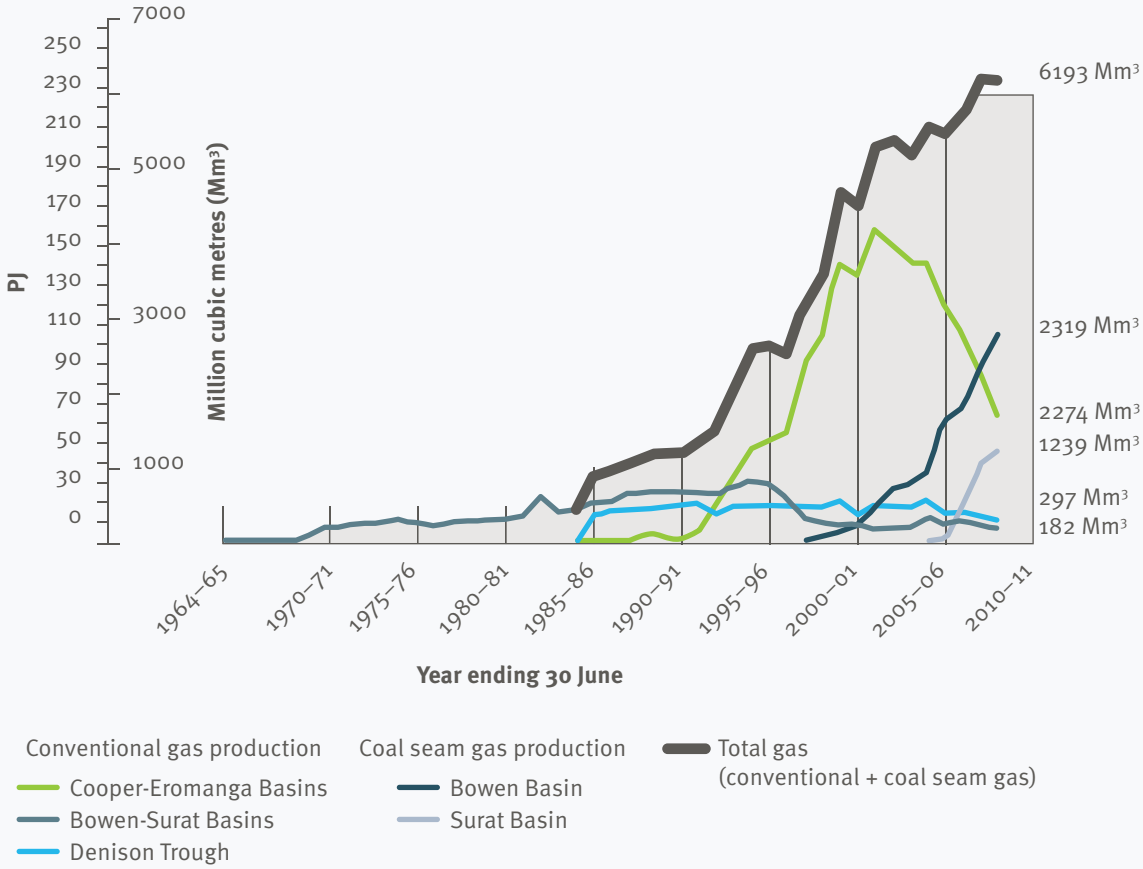



***Figure 2*** *Conventional and coal seam gas production, 1964–2011*

*Source: Department of Employment, Economic Development and Innovation (2010)*

## Development of the eastern Australian gas market

The eastern Australian gas market—which consists of New South Wales, Victoria, Queensland, South Australia, Tasmania and the Australian Capital Territory—has a growing domestic gas demand. Analysis conducted for the GMR estimates 2010 demand at an annual 704 PJ. Table 1 shows annual demand for gas by state. This demand is supplied from conventional and CSG reserves.

***Table 1*** *Gas demand by state, at 31 December 2010 (PJ/year)*

| State | NSW | Victoria | SA | Tasmania | Queensland | Total |
|---|---|---|---|---|---|---|
| Demand | 148 | 221 | 106 | 16 | 214 | 704 |

*Source: SKM MMA (2011)*

The eastern Australian gas market operates with long-term gas sales agreements (GSAs) between gas producers and buyers such as retailers, large industrial users and generators. Gas is delivered via equally long-term transmission agreements.

Historically, Australian gas markets have operated in isolation from one another. However, the past decade has seen increasing development and interconnection of gas transmission infrastructure and, in Queensland, the rapid growth of CSG in new locations closer to demand centres. The majority of eastern Australian sub-markets are now served by multiple basins and/or pipelines, the key exception being Townsville. The QSN Link

Pipeline between Ballera and Moomba, which started operations in February 2009, directly links Queensland supply to the southern states, replacing the previous swap arrangements.

These changes have brought gas supply conditions and prices closer and, together with the national and state gas market reform process, have led to the development of the eastern Australian gas market. The market is underpinned by a range of regulatory mechanisms such as the gas access regime, the National Gas Market Bulletin Board, the Short Term Trading Market (STTM) operated by Australian Energy Market Operator (AEMO) and, in Victoria, the market carriage/gas pool market also operated by AEMO.

The growth of gas producer competition in Queensland in the period 1998 to 2007 was sufficient to maintain price levels for new GSAs and to reduce prices in some Queensland sub-markets. But by 2007–08, it had become evident that the availability and potential of gas reserves in Queensland had outstripped existing and potential demand and viable economic access to the greater east coast Australian gas market. Queensland CSG producers then looked to access international gas markets via LNG. This has brought about the most recent changes to the eastern Australian gas market.

Although it will be four to six years before exports of LNG start from Queensland (based on current schedules), the export projects have already begun to change the domestic supply–demand dynamic. This change is compounded by the consolidation of CSG producers and the involvement, since 2007, of global energy companies such as BG Group, ConocoPhillips, Petronas and Shell together with large offshore gas purchasers such as China National Petroleum Corporation, Kogas and PetroChina. These changes are expected to result in different decision-making processes regarding investment in CSG production. Customers have expressed concerns regarding the domestic market focus of companies with no history in Australian domestic markets.

The primary factors expected to influence the future direction of the gas industry in eastern Australia are LNG exports and carbon pricing.

## LNG development projects

LNG development projects began to appear on drawing boards from 2007 and the first CSG-based LNG project was announced in May 2007. Four of these projects have achieved 'significant project' status and three have all the necessary approvals in place for the projects to proceed.

Two projects—Queensland Curtis LNG (QCLNG) operated by Queensland Gas Company, a subsidiary of BG Group, and Gladstone LNG (GLNG), operated by Santos—have reached final investment decisions (FIDs) and are committed to constructing the first two trains of their respective projects. 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.

Australia Pacific LNG (APLNG)—a consortium between Origin Energy, ConocoPhillips and Sinopec—reached FID in July 2011 for the project's first train and infrastructure to support a second train. APLNG expects to reach FID for the second train in 2012.

The Arrow Energy LNG Project is owned in a 50-50 joint venture by Royal Dutch Shell and China National Petroleum Corporation (PetroChina). It is also under development with an environmental impact statement (EIS) being prepared.

More detailed information on the four major LNG projects is provided in Table 2.

*Table 2 Queensland LNG major project structure and key parameters*

| Project | Trains No. x Mtpa | Date announced | Participants | Participation | | Committed customers (HoA or MoU) (Mtpa) | Significant project declaration | Environmental approval | | FID | Train start-up schedule |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Upstream (Production) | Downstream (Liquefaction) | | | QLD | Federal | | |
| Queensland Curtis LNG (QCLNG) | 3 x 4.25 | 1 Feb 08 | • Queensland Gas Company (wholly owned by BG Group)<br>• Tokyo Gas<br>• China National Offshore Corporation | • 93.75%<br>• 1.25%<br>• 5% | • 87.5%<br>• 2.5%<br>• 10% | CNOOC (3.6)<br>Tokyo Gas (1.2)<br>Singapore ( up to 3)<br>Chile (1.7)<br>Chubu Electric (0.4) | 4 Jul 2008 | 23 Jun 10 | 22 Oct 10 | 31 Oct 10 | 2014<br>2015<br>3rd later |
| Gladstone LNG (GLNG) | 3 x 3.6 | 18 Jul 07 | • Santos<br>• Petronas<br>• Total<br>• KOGAS | • 30%<br>• 27.5%<br>• 27.5%<br>• 15% | • 30%<br>• 27.5%<br>• 27.5%<br>• 15% | Petronas (3.5)<br>KOGAS (3.5) | 16 Jul 2007 | 28 May 10 | 22 Oct 10 | 13 Jan 11 | 2015<br>2016<br>3rd later |
| Australia Pacific LNG (APLNG) | 4 x 4.5 | 8 Sep 08 | • Origin Energy<br>• ConocoPhillips<br>• China Petroleum Corporation | • 42.5%<br>• 42.5%<br>• 15% | • 42.5%<br>• 42.5%<br>• 15% | Sinopec (4.3) | 9 Apr 2009 | 8 Nov 10 | 21 Feb 11 | 28 Jul 11 | 2015<br>2016<br>3rd and 4th later |
| Arrow LNG Project (Arrow LNG) | 4 x 4 | 16 Feb 09[1] | • Shell<br>• PetroChina | • 50%<br>• 50% | • 50%<br>• 50% | PetroChina (n/a) | 12 Jun 2009 | Pending IES | Pending IES | late 2013 (target) | 2017?<br>Others later |

[1] This is the original date of a Shell proposal for a 4 x 3–4 Mtpa project on Curtis Island. The joint venture bid for Arrow was announced on 8 March 2010.

In addition to the four major projects, there are a number of smaller LNG projects of less than 3 million tonnes per annum (Mtpa). These are:

- *LNG Limited's LNG Project at Fishermans Landing (Gladstone LNG Project)*: The project is operated by Gladstone LNG Pty Ltd, a subsidiary of LNG Limited. On 28 January 2011, LNG Limited announced an agreement with Huanqiu Contracting and Engineering Corporation (HQCEC)—a subsidiary of China National Petroleum Corporation—for HQCEC to acquire a 19.9 per cent stake in the company pending government approvals. Exports were initially projected to start in 2012; this has been revised to 2014, with the date conditional on the project securing gas supply.
- *Abbot Point LNG Project*: Energy World Corporation proposes to develop an LNG export plant at Abbot Point and/or Hay Point in Queensland. The initial phase of the project will involve four LNG trains of 0.5 Mtpa each and potential expansion to a total of 5 Mtpa. The project involves building a pipeline linking Abbot Point and Hay Point to the Bowen Basin and eventually through to Cooper Basin.
- *Southern Cross LNG Project*: The project is operated by Impel LNG, a wholly owned subsidiary of Galveston LNG. It is planned to be an open-access service to export LNG from Curtis Island near Gladstone, enabling gas producers not involved in LNG production projects to export their gas to international markets. The project involves three trains, each with a capacity of 0.7–1.3 Mtpa. The first train was originally scheduled to start up in 2013. This is now not achievable and there do not appear to have been any further developments associated with this project.
- *Metgasco Flex LNG*: In September 2010, Metgasco announced a memorandum of understanding (MoU) with Flex LNG to launch a feasibility study into the possibility of exporting LNG offshore using a floating LNG plant. The gas would be supplied by Metgasco's tenements in the Clarence-Moreton Basin in New South Wales although certified proved and probable (2P) reserves are not yet sufficient.
- *LNG Newcastle Project (LNGN)*: The project was announced in June 2010 with an MoU between Eastern Star Gas, Hitachi Limited and Tokyo Engineering Corporation for a feasibility study of an LNG export project in Newcastle, New South Wales. As of February 2011, the project had entered the front-end engineering and design phase (FEED) with completion expected mid-2011. The project has the possibility of reaching FID in 2012 and first export by 2015. The first phase of the project involves two trains of 0.5 Mtpa each using electric motor driven technology and a possible expansion up to 4 Mtpa. The plant will use gas from the Narrabri gas field in the Gunnedah Basin.
- *SA LNG*: An MoU between Beach Energy and Itochu Corporation to develop an LNG export facility in South Australia was announced in November 2010. The facility is proposed to have a capacity of 1 Mtpa, with supply expected to come from Beach Energy's gas portfolio of conventional and unconventional gas resources.

# Liquefied natural gas

Gas can be stored as a liquid until it is needed, then converted back to gas and shipped via pipeline or tanker to markets. Gas cooled to –161 °C at atmospheric pressure becomes a liquid that occupies less than one-six-hundredth of its original volume, making international transportation economical.

The natural gas liquefaction process dates back to 1873 when the first practical compressor refrigeration machine was developed in Munich. LNG was proven viable in 1917, when the first LNG plant began operations in the US. The first liquefaction plant to produce for the commercial market was built in Ohio in 1941.

In January 1959, the world's first LNG tanker carried LNG from the US to the UK, demonstrating that large quantities of LNG could be transported safely across the ocean. The modern era of LNG international transportation started in 1965 with the first commercial shipments of LNG from Algeria to the UK.

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

Once liquefied, the LNG is transferred to an LNG tanker for transport to the purchasing market.

In March 2011, there were 355 registered LNG tankers in operation worldwide. New LNG tankers have an average capacity of 3 billion cubic feet (bcf) and cost approximately $260 million each. LNG tankers typically have a number of separate holds or compartments.

## Global LNG market

The LNG market represents about 9 per cent of the global gas market. LNG is the primary source of supply in countries with no domestic gas, such as Japan, Korea and Taiwan, and a supplementary source in other countries, including the US, many European countries, China and India. LNG has recently been the most rapidly growing fossil fuel sub-sector, averaging 6 per cent between 2005 and 2009, compared to 3 per cent for the gas market as a whole. The LNG market has continued to grow through 2009 and 2010.

After falling by about 2 per cent in 2009 due to the global financial crisis, gas demand has rebounded and is on the rise according to energy outlook projections by the International Energy Agency and several others (IEA 2010; BP 2011; ExxonMobil 2011; EIA 2010). International demand is being driven by the increasing use of gas for electricity generation in preference to coal.

The LNG import markets are made up of the three broad regions of Asia, Europe and the Americas. The growth region is in Asia, with traditional LNG importers Japan, Korea and Taiwan recently joined by strong growth from China and India. Demand for gas in China is projected to increase annually by an average of 6–7 per cent, with demand from India expected to grow by 4–5 per cent per year. Brazil and the Middle East are also forecast to have growth of 4–5 per cent per year.

Gas is projected to continue displacing coal-fired generation as countries aim to reduce their carbon emissions.

SKM MMA (2011) notes that the development of the shale gas industry in the US has resulted in LNG that had previously been contracted for current and future delivery being diverted to other markets. This will impact LNG market demand and tanker movement; however, there is a broad consensus that global LNG demand will continue to enjoy growth rates of about 4.5 per cent per year over the coming decades, in a range of about 4–6 per cent.

## *LNG in Australia*

The LNG industry in Australia began operation in 1989, with supplies from the North West Shelf Project at Dampier, Western Australia, exported to Japan. This plant has been expanded to five trains and will be joined by the first train of Pluto LNG in 2011. Gorgon LNG, currently planned as three trains, has begun construction with scheduled operation in 2014. The single-train Darwin LNG operation started up in 2006. In addition to further trains at Pluto and Gorgon, there are a number of other Western Australian LNG projects in various stages of planning, including Wheatstone, Ichthys, Browse, Prelude and Scarborough.

The possibility of exporting LNG from the east coast of Australia has arisen as a result of significant growth in CSG reserves, which now exceed requirements of the Queensland and eastern Australian markets.

# Response to issues raised by the 2010 GMR

The 2010 GMR was undertaken in response to industry concerns about the operation of the Queensland gas market in light of the emerging LNG export industry. The report identified that domestic gas demand, supply and price outcomes in eastern Australia as a whole, and Queensland in particular, were critically dependent on the projected rate of development of projects to export LNG from Gladstone.

Based on the trends observed in the first half of 2010, there did not appear to be any prospect of a material imbalance of demand and supply. This was because, when broadly comparing the aggregate demand and supply requirements, a reserves buffer existed and no gas reserve adequacy issues were identified in the short to medium term. This meant there would be sufficient gas available to service the eastern Australian gas market and the LNG export industry, even when modelling assumed the strongest economic growth.

The 2010 GMR noted, however, that aggregate projections concealed the commercial reality that competition among LNG projects would reduce the volumes of gas available for the domestic market to levels that were considerably lower than the reserves buffer illustrated. The eastern Australian gas supply was projected to come increasingly from CSG, not only from Queensland but also New South Wales.

Projections of delivered gas prices in Queensland in the period 2020 to 2028 varied considerably between modelling scenarios and locations, with new contract prices projected to be in the range of $4/GJ (Low scenario) to $7.50/GJ (High scenario). The issue of export parity pricing was canvassed, with the report arguing that parity might not occur, depending on whether export capacity increased more rapidly than overall reserves growth.

Pipeline capacity was modelled and the report noted capacity appeared adequate for all major Queensland pipelines except the RBP, which appeared to be at full capacity.

The Queensland Government considered the 2010 GMR and, based on its findings, concluded that the intervention to secure future domestic gas supply through the development of the PGPLR was not warranted at the time.

It was decided that infrastructure capacity constraints on the RBP required investigation and that implementation of the STTM in 2011 was to be facilitated by the Queensland Gas Commissioner in order to continue to promote an efficient Queensland gas market.

## Capacity constraints on the RBP

### Constraints reports

Anecdotal reports of RBP capacity constraint issues are longstanding; gas market modelling for the 2009 and 2010 AEMO Gas Statement of Opportunities (AEMO 2009, 2010a) and the 2010 GMR all flagged future capacity constraints on the RBP.

A major new load, such as a gas-fired power station, can underpin and justify a pipeline capacity expansion. However new smaller volume demand for gas is not large enough to underpin a capacity expansion and, therefore, these customers can have difficulty in accessing new pipeline capacity. These smaller loads can represent new customers, existing customers that wish to expand or incremental market growth (small volume growth by a number of customers). A constraint on small load growth can have a marked impact on competition and overall gas market effectiveness and growth.

Following the Queensland Gas Commissioner taking up her role in September 2010, an investigation was undertaken of current RBP capacity constraints and the potential for future constraints. The investigation focused on the available capacity for small volume loads. The objective of the investigation was to:

- substantiate anecdotal reports
- establish the extent and impact of current constraints
- identify the basis of the modelling that projected significant future RBP demand growth.

To establish the nature, extent, impact and veracity of constraints, the Queensland Gas Commissioner consulted gas users directly and via the peak industry group Energy Users Association Australia (EUAA). In parallel with direct consultation, customers were surveyed with the assistance of the EUAA. This was to ensure that users had a variety of forums where they could freely discuss any RBP constraint issues they had encountered.

## *Pipeline capacity constraints*

Pipeline capacity expansions are achieved either by the addition of compressors that can compress the gas up to the maximum allowable operating pressure (MAOP) under the pipeline engineering specification, or by 'looping', which is the construction of duplicate, parallel sections of pipeline.

A gas pipeline is generally considered to be constrained if:

- the capacity of the pipeline does not meet actual demand and excess demand is not sufficient to underpin a capacity expansion
  or
- the pipeline owner is not willing to expand the pipeline
  or
- the pipeline has reached the maximum capacity of the physical and technical construction and no further expansion is possible.

Comments received were very general in nature and anecdotal; they provided no specific details to support claims. However, the comments did serve to outline some of the potential impacts of capacity constraints, including:

- lack of competition, leading to uncompetitive GSAs
- difficulty in swapping retailers
- higher gas prices due to increased transmission costs (resulting in a reduced rate of return for users' projects)
- inability or unwillingness to proceed with new investments
- security of supply implications.

The RBP owner, APA Group, advised that capacity was available on the RBP and was being actively marketed to potential users. In addition, a number of contracts had been agreed for capacity in the period 2009–10 and a major supply contract was being recontracted from mid-2012.

The STTM starts in Brisbane from December 2011 (see following section for details). The fundamental design of the STTM values firm transmission capacity as a signal to drive infrastructure investment such as pipeline expansions. Ahead of the start of the STTM, customers have reviewed their future transmission requirements; it is understood that in 2011, remaining RBP capacity has been contracted. A project to expand RBP capacity was being marketed to customers in 2010–11 and this project was subsequently finalised and announced on 28 April 2011.

Information on capacity and expansion projects under development is not widely disseminated to the market, which can give rise to perceptions of a problem when there is in fact none. More and better communication about available pipeline capacity and planned capacity expansions would help market participants understand and plan for pipeline capacity requirements.

To address this issue, the Queensland Gas Commissioner has initiated a number of strategies to improve market knowledge of capacity and expansion plans, including working with market participants. In addition, the start of the STTM is expected to improve the transparency of pipeline capacity, gas pricing and market participant activities.

## Modelling potential capacity issues

As noted previously, gas market modelling has flagged future capacity constraints on the RBP.

An investigation of the modelling outcomes has identified that many existing models have an assumption that all gas required for new South East Queensland gas-fired generation will be transported on the RBP. This assumption does not reflect recent gas-fired generation construction trends. For example, major new gas-fired electricity generators such as the Braemar and the Darling Downs power stations are located on the gas fields close to the Queensland–New South Wales Electricity Interconnector and do not take gas from the RBP. No new major gas-fired generator has connected to the RBP for primary gas supply since Swanbank E in 2002.

The potential for future RBP capacity constraints due to major new load has therefore been significantly overstated.

To address the issue of the overstating of future RBP demand growth, the Queensland Gas Commissioner has ensured that modelling for the 2011 GMR appropriately separates the growth in demand for gas-fired generation in South East Queensland. Future demand for RBP capacity and industry discussion will be monitored and clarified by the Queensland Gas Commissioner where necessary.

# Short Term Trading Market

## Background

The Ministerial Council on Energy (MCE) decided in 2004, as part of the national energy reform program, to expand the gas market segment of the program in order to increase the penetration of natural gas as a fuel, expedite development of a competitive gas market and ensure security of supply.

Later in 2004, the MCE approved the principles for gas market development as the basis for future development of the Australian wholesale gas market (MCE 2004). The aim was to deliver increased transparency, promote further efficient investment in gas infrastructure and provide efficient management of supply and demand interruptions.

During the period 2005 to 2009, the market concept and design was developed under the management of an industry stakeholder group—the Gas Market Leaders Group. In September 2010, following a market trial, the STTM commenced operations in Sydney and Adelaide.

## Brisbane STTM implementation

In November 2009, the Queensland Government announced a range of new measures designed to enhance gas market competition and promote transparency in the state's gas market in light of the emerging LNG export industry. These initiatives included the implementation of the gas STTM in Brisbane.

In the second half of 2010, AEMO established a project team in Brisbane to manage the implementation. The Queensland STTM Working Group of gas market participants was also established to provide input and ensure liaison and consultation on issues arising from implementation. The Queensland STTM Working Group and AEMO are working towards a market trial starting in September, with STTM operations to start in December 2011.

In 2011, AEMO and participants are testing market readiness, reviewing underlying contractual arrangement for gas supply and transmission services, and commissioning data management systems.

The Queensland Gas Commissioner is facilitating the STTM implementation and has supported AEMO and participants in addressing a number of confidential issues arising from contractual arrangements and market operations. Facilitation will continue in the lead-up to the December start date.

# STTM operation

The STTM is a mandatory wholesale gas market authorised by the National Gas Law, which establishes the broad governance principles. The National Gas Rules specify the operational aspects of the STTM and are supplemented by market procedures which are developed by AEMO to cover technical or procedural matters.

All gas sales and purchases through specified custody transfer points, including gas supplied under existing long-term gas supply contracts, take place within the STTM. Each STTM hub is scheduled and settled separately. Trading participants bid and are exposed to the market. However, entities may sell gas into the STTM and buy gas from the STTM to reflect their contractual requirements and to meet their demand.

## Features of the STTM

- Gas is traded a day ahead of the actual gas day and the day-ahead price (ex ante market price) is applied to all gas that is supplied according to the market schedules through the hub on the gas day.
- A market price is set each day at each hub for clearing all trades in the ex ante market.
- The market provides financial incentives for participants to keep to their schedules and, by doing so, provides financial drivers for keeping the gas supply system balanced.
- Bids and offers are scheduled based on price to deliver the maximum benefit to the market as a whole and, when required, the market ensures that firm shippers are compensated when non-firm, lower priced shippers use the capacity that they have funded.
- Mechanisms for balancing flows to and from the hub are part of the normal daily operation of the market, and system security events are resolved systematically using a clearly defined set of procedures.

## Key features preserved by the STTM

While the STTM brings many important changes to the gas supply system, it also preserves a number of important features of the existing system:

- AEMO only operates the STTM and has no involvement in how production facilities, transmission pipelines, storage facilities and distribution networks are operated. These facilities continue to be operated and scheduled by their owners.
- The fundamental contract carriage arrangements on which the industry (outside Victoria) is based are preserved. The contractual arrangements between pipeline operators and shippers for haulage priority and contracted capacities are recognised in the STTM and form the basis for the trading rights issued by AEMO by which all gas is bought and sold.
- Although AEMO plays a key role in assessing and resolving system security events, it is not responsible for system security, which remains the responsibility of the operators and governments.

The information provided above is sourced from AEMO (2010b, 2011). Further information on the STTM is available from the AEMO website at www.aemo.com.au

The National Gas Law is set out in the Schedule to the *National Gas (South Australia) Act 2008* (SA). It is applied as a law of South Australia by that Act, and as a law of other jurisdictions by their application Acts. The National Gas Law can be found at the South Australian legislation website, www.legislation.sa.gov.au

The National Gas Rules are available from the website of the Australian Energy Market Commission, www.aemc.gov.au

# Modelling scenarios

The modelling for the 2011 GMR was conducted by SKM MMA (2011). The scenarios and the assumptions made are explained in this section.

Key direct inputs and scenario variables for the modelling included:

- domestic gas demand and LNG export development in Queensland
- energy prices, particularly international oil prices and gas prices
- electricity market assumptions—demand, policy settings and gas input prices
- economic parameters, including economic growth and associated commodity prices
- carbon policies, specifically the price of carbon
- gas production costs
- gas reserves estimates and projections.

## Economic scenarios

For the 2011 GMR, three economic scenarios were developed. They are referred to as High, Medium and Low because they largely correlated with high, medium and low economic parameters, although they are not the only parameters used. The scenarios also correspond to high, medium and low gas demand for both the domestic and export sectors, but this reflects the assumed economic environment. The 2011 GMR scenarios are outlined in Table 3.

***Table 3*** *Scenario outline for the 2011 GMR*

| Scenario | High | Medium | Low |
|---|---|---|---|
| Economic growth | High | Medium | Low |
| Emission targets below 2000 in 2020 | 25% | 15% | 5% |
| LNG development | Refer to page 22 *(LNG in the modelling scenarios)* | Refer to page 22 *(LNG in the modelling scenarios)* | Refer to page 22 *(LNG in the modelling scenarios)* |
| Energy prices | High oil & gas<br>Oil = $US140/bbl<br>Gas = $A7–9/GJ<br>$US/$A =1.00 | Moderate oil & gas<br>Oil = $US100/bbl<br>Gas = $A5–7/GJ<br>$US/$A = 0.80 | Low oil & gas<br>Oil = $US60/bbl<br>Gas = $A4–5/GJ<br>$US/$A = 0.60 |
| Electricity market assumptions | As per 2010 GSOO* | As per 2010 GSOO* | As per 2010 GSOO* |

* Refer to AEMO (2010a) for electricity market assumptions.

Oil price scenarios used in the modelling were adopted from the U.S. Energy Information Administration's *Annual Energy Outlook 2011* (EIA 2011). In the Medium and High

scenarios the values have been deliberately chosen by SKM MMA to represent the medium-term outlook that will impact on LNG pricing and potentially domestic pricing over the next five to six years when the Gladstone LNG projects will commence export. Variable exchange rates were selected on the basis that the Australian dollar is strongly commodity price dependent—a rate of 0.80 $US/$A is KPMG Econtech's medium-term projection (KPMG Econtech 2011).

## Technical/Operational Impacts scenario

Economic assumptions provide a framework for assessing impacts on the broad marketplace in which the gas industry will operate in the modelled period; they are sufficient when modelling for the medium and long term, as economic influences have the time to drive infrastructure and market responses.

The Queensland Gas Commissioner has noted that infrastructure and market responses have implementation time frames which cannot always be met in the short term. Therefore, when modelling into the near future, it was considered desirable to model and assess the potential impacts of technical and operational constraints on Queensland gas industry outcomes.

The time frame in which reserves can be developed, for instance, is likely to be two to three years for appraisal and reserves declaration, followed by three to four years before first production. This is assuming the reserves are contracted soon after they are declared due to strong demand. This aligns with the proposed time frame for development of the LNG export projects in the period 2008 to 2015.

It is assumed that, in order to forecast gas supply shortfall, the modelling window is approximately seven years. In order to forecast a reserves shortfall (for contracting for supply in five to seven years) the modelling window is approximately three to four years. This is the period where economic influences and market responses may not be able to mitigate technical and operational impacts.

There are a number of technical and operational constraints that can impact gas supply such as:

- access to sufficient equipment and material such as drill rigs and pipe
- the ability to hire qualified and experienced staff to operate equipment
- the time frames required to construct infrastructure
- operational conditions such as the impacts of weather.

Consultation for the 2011 GMR highlighted access to sufficient equipment and material and the ability to hire qualified and experienced staff as issues that were being adequately managed by LNG project proponents. However, other smaller producers noted an impact when competing for these resources.

In modelling the time frames required to construct infrastructure, the major consideration was the ability to develop infrastructure projects to link additional gas resources to the existing Queensland transmission network. An economic response would assume this can be done, but in the period 2011 to 2015–16, this could only be achieved if a significant start had already been made. The gas transmission pipelines under development by the LNG project proponents are examples of infrastructure that is planned to be operational in that period. A pipeline connection to potential southern gas resources is an example of infrastructure that is not planned to be operational in the time frame.

The Technical/Operational Impacts scenario assumes that, when no start has been made, gas pipeline infrastructure and reserves cannot be developed in the time frame.

During the period of rapid development of CSG in Queensland in the period 2000–01 to 2008–09, South East Queensland experienced severe drought; summer rainfall events had minimal impact on access to land for appraisal drilling and well development. The current year, 2010–11, has seen major flood events across the state. This has impacted producers' appraisal programs and subsequent reserves development and it seems unlikely that the reserves growth achieved in 2007–08 and 2008–09 will be achieved in 2010–11. There could be additional impacts on appraisals in the coming years if recent weather patterns signal a return to heavy wet seasons.

Appraisal drilling is currently focused on developing 2P reserves to underpin LNG sales contracts. If appraisal drilling and reserves development is delayed, then availability of reserves for contracting domestic sales for gas supply in the period 2015 to 2020 will also be delayed.

In order to assess the potential impact of weather and floods on reserves growth, it is assumed that 2P reserves growth is restricted to 50 per cent of maximum achievable levels in 2010–11 and 2011–12; this is referred to as the 'flood scenario' in the SKM MMA report (2011).

Contract requirements are based on the assumption that the duration of new contracts is 10 years.

# Natural disasters cause delays in appraisal drilling programs

Natural disasters and severe rainfall from September 2010 onwards saw more than 75 per cent of the state declared a disaster zone. The floods in December 2010 and January 2011 and rainfall from Cyclone Yasi in February 2011 hampered access to gas wells, but caused minimal damage to infrastructure and had a limited impact on CSG production.

However, the adverse weather brought CSG drilling in the Surat and Bowen basins to a standstill, and appraisal programs and subsequent reserves development have been impacted.

Producers report that in some areas all drilling, hydraulic fracturing and work-over activities ceased during December and disruptions continued into the March quarter 2011. Rain in the aftermath of the floods and poor ground conditions persisted for quite a long time after the floods abated and access to drill sites and planned drill sites was restricted for long periods.

Drill work-over rigs were placed on wet weather standby and, in some cases, rigs were caught in the primary flood zone, suffering extensive damage. The flooding also limited the movement of specialist equipment in and out of the flood-affected regions, which added to delays.

Companies with offices in the Brisbane central business district experienced significant office closures and disruption to normal business activities and communications.

To mitigate the impact on appraisal drilling programs, producers changed drilling sequences to the extent possible, moved drilling to areas that could be accessed and are considering ways to accelerate the drilling programs by using more rigs.

Although producers report that operations were nearly back to normal by mid-2011, it seems likely that the level of reserves growth achieved in 2007–08 and 2008–09 will not be achieved in 2010–11.

There could be additional impacts on appraisals in the coming years if recent weather patterns signal a return to high rainfall wet seasons.

## LNG in the modelling scenarios

For its 2011 GMR scenario modelling, SKM MMA selected 4.5 per cent as the base global LNG demand growth rate for the Medium scenario. For the High and Low scenarios, growth rates were varied by economic factors impacting global LNG growth—the High scenario growth rate was set at 6.5 per cent and the Low scenario growth rate was set at 2.5 per cent.

The rate of LNG train build-up in eastern Australia will be impacted by the global requirement for new trains to meet global LNG demand. Globally, the average number of new trains per year after 2018 required to meet demand under each scenario is as follows:

- High scenario: 11
- Medium scenario: 6
- Low scenario: 4.

SKM MMA also assumed that the total number of trains starting up in eastern Australia beyond 2018 would be proportional to the global requirement. For the High scenario this means one train per year is constructed, i.e. approximately 9 per cent of world incremental capacity. This is lower than the two per year rate that will be achieved between 2015 and 2017, because greater competition from other projects is assumed.

Based on 9 per cent of global capacity, the train construction rate for the Medium scenario would be approximately one every two years and for the Low scenario, one every three years, starting in 2021. This is further modified by the following assumptions:

- High scenario: a cap of 17 trains on Curtis Island, the number currently approved
- Low scenario: given the slow growth rate and further global competition, all growth is eliminated, i.e. the number of trains is capped at 5
- Medium scenario: for symmetry between the High and Low scenarios, the number of trains is capped at 11.

To cover uncertainty in the reserves–production relationship, the modelling assumed that a temporary additional reserves margin of 20 per cent is imposed at the time the LNG is contracted. The reserves margin is released when the gas is produced four years later and the uncertainty is eliminated.

It is also assumed that no reserves are made available by LNG proponents to the domestic market for new contracts until 2014 or later.

## Gas production cost assumptions

For the purposes of modelling for the 2011 GMR, SKM MMA assumed gas production costs (excluding carbon costs) to be:

- CSG and Gippsland Basin conventional gas: $3.50/GJ
- other conventional gas: $4.00/GJ.

These costs are assumed to be constant in real terms and across all scenarios. Carbon costs are scenario specific, and are based on the scenario carbon costs and producer-specific estimates of carbon dioxide content and gas used in production. In the 2010 GMR, the starting costs were similar but a real cost decline of 1 per cent per year was assumed and carbon costs were not scenario specific.

## LNG price assumptions

The delivered price of LNG depends primarily on the price of crude oil (using the Japan Customs-cleared Crude (JCC) measure, also known as the Japan Crude Cocktail) and the US dollar to Australian dollar conversion rate ($US/$A), and secondarily on the link between LNG prices (in US dollars per million BTU, or $US/mmbtu) and the JCC price (in US dollars per barrel or $US/bbl). For the 2011 GMR modelling, SKM MMA used a direct linkage without a cap or floor:

LNG price = 0.15 * JCC price

This formula is believed to apply to GLNG contracts (Santos 2011) and implies that at $US80/bbl oil, the LNG price is $US12/mmbtu.

SKM MMA estimates that liquefaction plus shipping costs would range from $5.35/GJ for a $US/$A rate of 1.00 up to $9.19/GJ for a $US/$A rate of 0.60 (the exchange rates applying during construction, when most costs are incurred). The resulting netback prices at the oil prices and exchange rates in the three scenarios are shown in Table 4. The values are slightly lower than comparable estimates used in the 2010 GMR because of escalation in liquefaction costs.

*Table 4* LNG netback values at Gladstone

| | Low scenario | Medium scenario | High scenario |
|---|---|---|---|
| JCC price ($US/bbl) | $60 | $100 | $140 |
| Exchange rate ($US/$A) | $0.60 | $0.80 | $1.00 |
| LNG netback value ($A/GJ) | $7.45 | $12.89 | $16.15 |

*Source: SKM MMA (2011)*

For the purposes of constructing the LNG demand function, SKM MMA assumed that purchasers will not be prepared to pay more than the netback value at Gladstone for gas delivered to Gladstone, because a higher price would render the LNG project uneconomic, i.e. demand for LNG contracts is effectively zero at delivered prices above netback.

It is also assumed that sellers will be unwilling to sell at a price below their cost of production plus transmission to Gladstone, which for typical CSG producers would be in the range $4/GJ to $5/GJ. A value of $4.50/GJ is assumed in all modelling. The LNG demand function used in the SKM MMA modelling assumes that forecast demand is met at a price midway between these extremes, as illustrated in Figure 3.

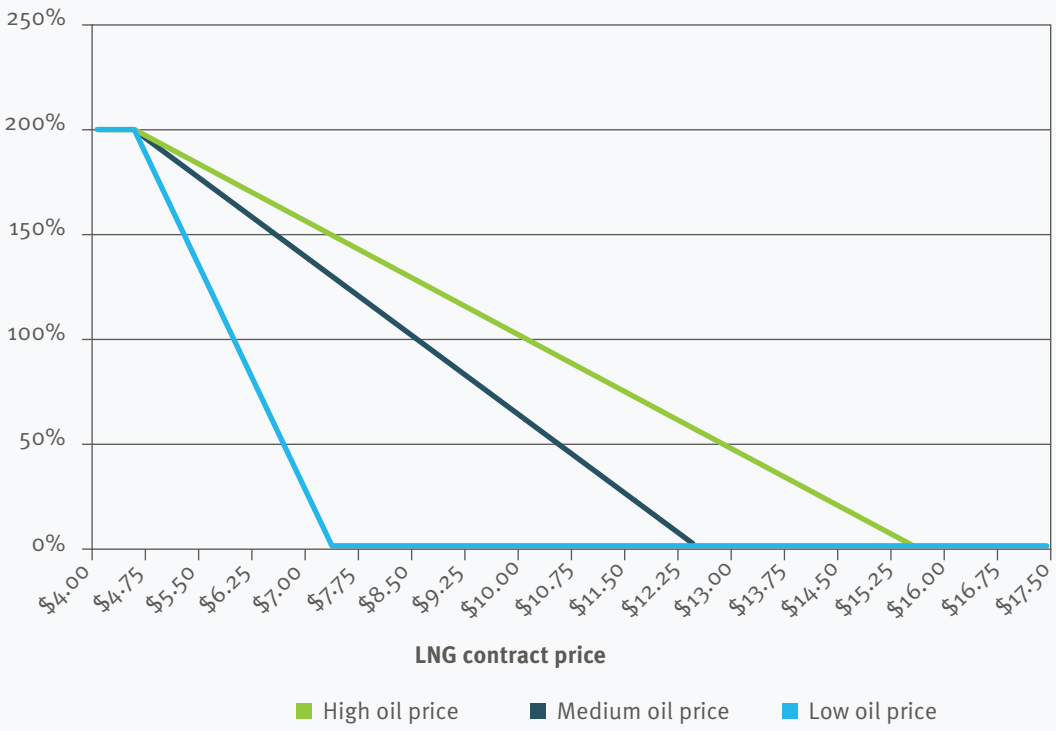



*Figure 3* LNG contract demand functions

*Source: SKM MMA (2011)*

## Ramp-up gas assumptions

Ramp-up gas is the unavoidable gas produced by LNG project CSG wells before LNG plant start-up, owing to the difficulty of shutting-in CSG production. Ramp-up gas management could be achieved by one or more of the following: placing the gas in underground storage; disposing of it cheaply to electricity generators or other users who can take more than their current contracts; transporting it to southern markets; or temporarily displacing gas from conventional fields that can be turned down without impacting future production capability.

SKM MMA has estimated that for the first train, 100 to 200 PJ of gas would need to be managed. However, for the second train most ramp-up gas could be absorbed by turning down the wells supplying the first train.

Ramp-up gas is a short-term phenomenon likely to result in cheaper gas being available to some domestic users, mainly one and two years prior to first train start-up, i.e. in the period 2012, 2013 and possibly 2014. It is unlikely to have a long-term influence on contract terms or contract prices.

## Domestic gas price assumptions

Gas price projections for all three economic scenarios are for gas prices delivered to zonal hubs (i.e. include transmission costs) and are expressed in real 2011 dollar terms. The underlying assumptions include negotiation four years in advance (e.g. the price for 2014 is assumed to have been negotiated in 2010). Also, the estimated average prices cover all gas contracts delivering gas in any year.

Ramp-up gas produced in the period 2011 to 2013, because of the short-term availability, is incompatible with other contracts. However some ramp-up gas is included in initial contracts and is captured in the average price in Queensland up to 2014.

## Gas transmission assumptions

Because the cost of delivered gas to customers on transmission pipelines is made up of approximately 75 per cent wellhead price and 25 per cent transmission price, the focus when matching demand and supply is on the wellhead component of supply rather than transmission. The modelling for all scenarios assumes that:

- existing pipelines are unconstrained, i.e. capacity can be added by further compression or duplication
- pipeline tariffs continue at current levels/escalation rates.

For the economic scenarios, it is assumed that uncommitted new pipelines can be added, but that their projected throughput must be tested to ensure commercial viability. New pipelines have been included as follows:

- Pipelines to convey CSG from the southern Bowen and Surat basins and from the northern Surat Basin (Moranbah) to Gladstone for the LNG projects. Pipeline start-up timing is aligned with LNG project timing. Pipeline tariffs are estimated to be $0.70/GJ with Consumer Price Index (CPI) escalation.
- A modified version of the proposed Queensland Hunter Gas Pipeline to convey CSG from the Gunnedah and Gloucester basins north to Wallumbilla and south to Wilton to compete in the broader New South Wales market. Pipeline start-up is assumed to be 2015 in all scenarios. At throughput rates of 50 PJ/year the tariffs for both the north and south sections are estimated at $1.00/GJ escalating at CPI. At these tariffs the cost of shipping Queensland CSG from Wallumbilla to Wilton through this pipeline is comparable to the cost of shipping through the existing pipelines (South West Queensland Pipeline–QSN Link Pipeline–Moomba to Sydney Pipeline).
- The Lions Way pipeline linking Clarence-Morton CSG production in northern New South Wales with Brisbane. Pipeline start-up is assumed to be 2015 in all scenarios. The pipeline tariff is estimated to be $0.50/GJ with CPI escalation.

For the Technical/Operation Impacts scenario, which looks at the period 2011 to 2015–16, it was assumed that the new, uncommitted pipeline projects just listed cannot be developed and constructed in the time frame. This means that gas reserves cannot be included from areas that would be serviced by these pipelines.

# Gas demand

SKM MMA estimates the 2011 eastern Australian demand at 704 PJ/year. Demand for gas within eastern Australia is considered in two segments: domestic and LNG export. Domestic demand is further broken down into customer segments.

## Customer segments

### Domestic

- *Utility*—residential, small business and larger commercial and industrial customers who are supplied principally from distribution mains. Utility demand was modelled using regression analysis taking into account population, size and number of dwellings, gas connection numbers, retail gas prices, energy efficiency policies, and weather and climate change.
- *Large industrial*—customers consuming significant quantities (typically more than 1–2 PJ/year) who 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. Also, utility and large industrial demand are largely driven by economic growth assumptions, with some gas price effects that closely link to the modelling scenarios.
- *Gas power generation* (GPG)—gas for power generation, including large cogeneration projects. Gas power generation 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. Modelling of electricity demand uses the demand projections provided by the AEMO Market Modelling group for the Gas Statement of Opportunities (AEMO 2010a).

### LNG export

- *LNG*—projected gas usage for LNG which takes into account expected global LNG demand under the scenarios and the proposed CSG-based Gladstone export projects.

## Carbon pricing

In electricity generation, carbon pricing has the effect of making gas more competitive with coal, but simultaneously less competitive with low- or no-carbon options such as renewables. On balance, it appears in the modelling scenarios that carbon pricing favours gas in the period to 2030, after which renewables or new technologies may depress gas demand for generation.

A secondary effect of carbon pricing on gas is the expected growth of peaking gas generation plant to support intermittent renewable generation such as wind. Peaking gas plant will require more flexible gas supply, which may necessitate investment in gas storage (underground, LNG or linepack pipelines) or liquid fuel back-up.

Carbon pricing will also increase the end-use cost of gas for other usage, potentially reducing usage in non-generation sectors. However, care must be taken to fully account for the substitution opportunities opened up by carbon pricing. In terms of the gas wholesale market, however, the impact will most likely be limited as the only costs borne in this market are the carbon costs of gas used in production and pipeline compression; the carbon costs of combustion or feedstock use are paid by end-users or retailers.

## Domestic demand modelling outcomes

The eastern Australian gas market is, in reality, a series of state markets. Queensland, more so than any other eastern Australian state, also has a series of sub-markets with different characteristics. For the 2011 GMR, the state markets and the Queensland sub-markets are considered separately as:

- Queensland: Brisbane, Gladstone, Mount Isa and Townsville
- New South Wales
- Victoria
- South Australia
- Tasmania.

The demand modelling uses the three economic scenarios.

## Queensland markets

### *Brisbane*

The Brisbane gas market is supplied via the Roma to Brisbane Pipeline (RBP). Major customers are Incitec Pivot, BP, Caltex, retail/distribution in and around Brisbane and GPG at Swanbank and Oakey. Demand is approximately 63 PJ/year with a utility and large industrial demand of approximately 50 PJ/year.

It should be noted that previous modelling of the Brisbane gas market and RBP future capacity requirements have effectively included all future projections for GPG in the South East Queensland (SEQ) region. That is, it has been assumed that gas supply to all new SEQ GPG projects will flow through the RBP. This assumption does not reflect the reality that new GPG projects are locating on the gas fields and taking primary gas supply directly from these fields. For the modelling of future gas demand for the Brisbane region, new GPG for the SEQ region has been considered as separate from the Brisbane gas market and RBP capacity requirements.

The Brisbane utility plus large industrial demand load over the period 2010 to 2029 is forecast to grow at a slow but steady rate of between 1.2 per cent and 1.8 per cent; the results are very similar for all modelled scenarios (Figure 4).

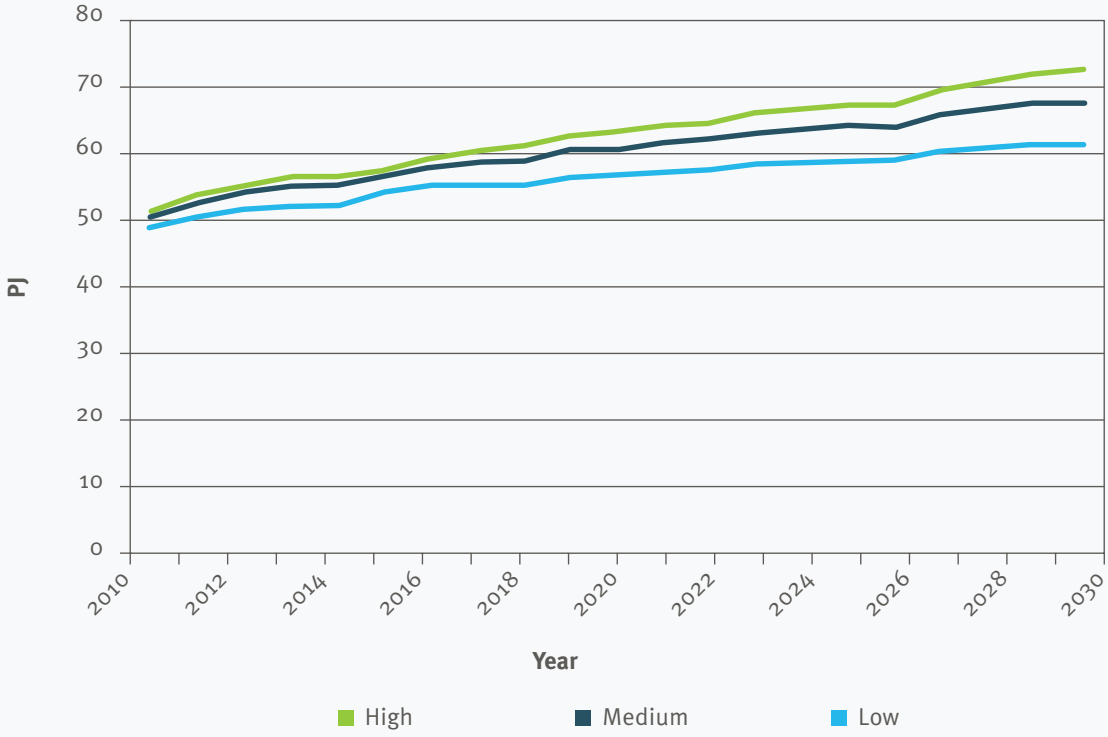



***Figure 4*** *Large industrial demand projections for Brisbane, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

## *Gladstone*

Gas is currently supplied to the Gladstone market via the Queensland Gas Pipeline (QGP). Gladstone is a large industrial load centre with major customers such as Queensland Alumina Limited, Rio Tinto, Orica and Boyne Island Smelter. There is a utility load, but it is so tiny it does not impact modelling. Queensland Magnesia at Parkhurst and Queensland Nitrates at Moura are also supplied via the QGP. Demand is approximately 33 PJ/year.

It is noted that there are five projects for the construction of new gas pipeline to Gladstone for the supply of gas for LNG export. This future load is modelled under the LNG segment.

All scenarios show significant lumpy increases over the period, related largely to cogeneration and potential major user expansions (Figure 5). The Medium and Low scenarios are similar, with gas consumption in the Low growth scenario close to gas consumption under the Medium scenario in 2015 and 2016. This appears to be due to a large industrial project made attractive under the Low scenario, even though the gas price is the same under both these scenarios. Projected demand load over the period 2010 to 2030 is forecast to grow between 5.9 per cent and 8.4 per cent. If gas prices are too high to bring on a major new (non-LNG) project, the forecast demand growth is reduced at the lower end to 3.8 per cent.

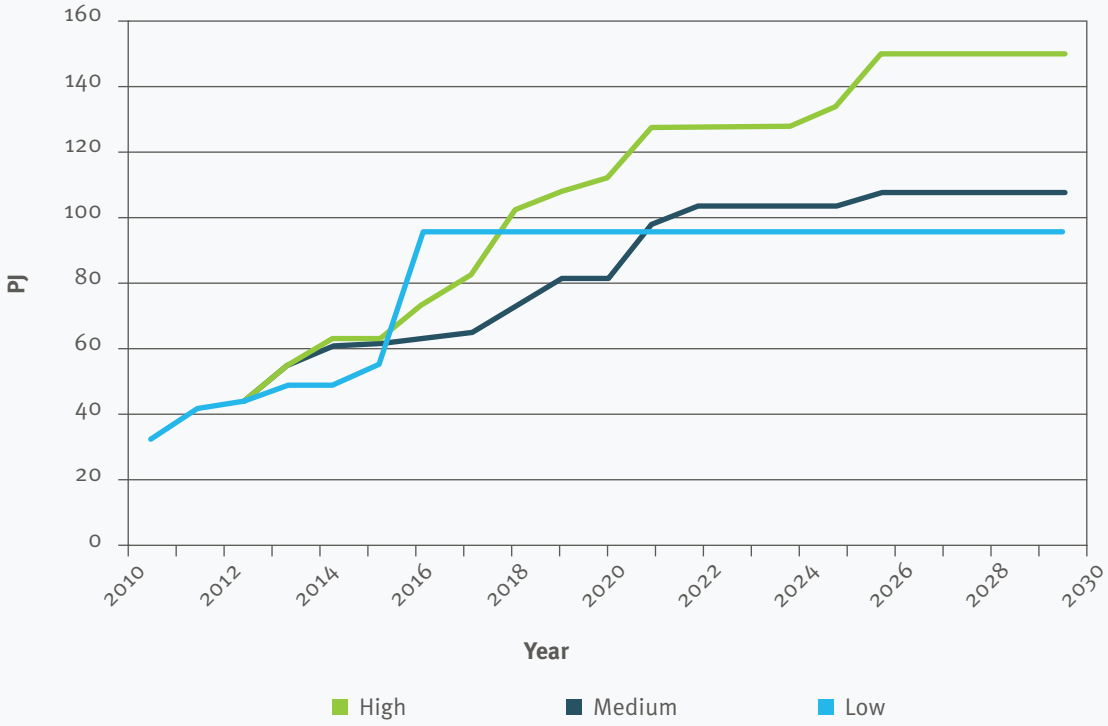



***Figure 5*** *Large industrial demand projections for Gladstone, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

## *Mount Isa*

The Mount Isa gas market is supplied via the Carpentaria Gas Pipeline (CGP). Mount Isa is a large industrial load centre with Incitec Pivot and GPG customers Mica Creek Power Station and Xstrata Power Station. Other customers are BHP Billiton Cannington and Ivanhoe Australia, which are supplied gas via the Cannington Lateral. Total Mount Isa region demand is approximately 33 PJ/year.

Demand growth in the Mount Isa market has a number of mining-related variables, including mine life and expansion, and new mine projects. Also, electricity generation for Mount Isa is gas powered and supplied via the CGP. The project to connect the Mount Isa electricity market to the National Electricity Market (NEM) via cable from either central or northern Queensland would impact CGP gas flows significantly.

To model these variables, electricity import is envisaged in the High scenario, reducing gas demand by about 20 PJ/year. It is for this reason that the High scenario growth outcome is lower than either the Low or Medium scenarios, which are very similar in load shape and volume (Figure 6).


***Figure 6*** *Large industrial and GPG demand projections for Mount Isa, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

## *Townsville*

The Townsville gas market is supplied via the North Queensland Gas Pipeline (NQGP). Townsville is a GPG market for the Townsville Power Station and has large industrial load for major customers Queensland Nickel and Copper Refineries Limited. Also included in the Townsville market is demand at Moranbah for supply to IPL/Dyno Nobel. Demand growth for Townsville is large because of future GPG needs. For Townsville the Low scenario is largely 'business as usual' (Figure 7).


***Figure 7*** *GPG and large industrial demand projections for Townsville, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

## Gas power generation

GPG demand is driven by a wide range of factors other than utility and large customer load, particularly carbon policy assumptions and decentralisation, as well as economic growth and gas price. For the 2011 GMR, SKM MMA generally used the market outcomes from the AEMO Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO) (AEMO 2010a, 2010c).

The economic scenarios for the 2011 GMR align with the GSOO scenarios as follows:

| GMR 2011 scenarios | GSOO 2010 scenarios |
|---|---|
| High | Decentralised world |
| Low | Slow rate of change |

The GMR's Medium scenario is an average of the High and Low scenarios (50–50).

Aggregate GPG modelling outcomes show a doubling of load from 200 PJ/year to 400 PJ/year between 2012 and 2014, mostly in Victoria due to assumed retirement of brown coal generating plant. This outcome may be implausible because of the requirement to run major new GPG plant at 75 per cent capacity, as it is unlikely that other as yet uncommitted plant would be built in the time frame. In addition, Victorian peak gas demand exceeds current gas production and pipeline capacity by 2013 and it is unlikely that gas will be contracted at a price that makes this level of activity attractive.

Nevertheless, GPG demand is expected to grow at this level and the location of new plant may well be away from the assumed demand centre.

### Eastern Australian aggregate domestic demand projections

When Queensland domestic gas demand is aggregated with demand from New South Wales, Victoria, South Australia and Tasmania, growth is strong in all scenarios (Figure 8). Demand outcomes by 2030 are in the range of 1200 PJ/year (41% increase) to 1850 PJ/year (62% increase).

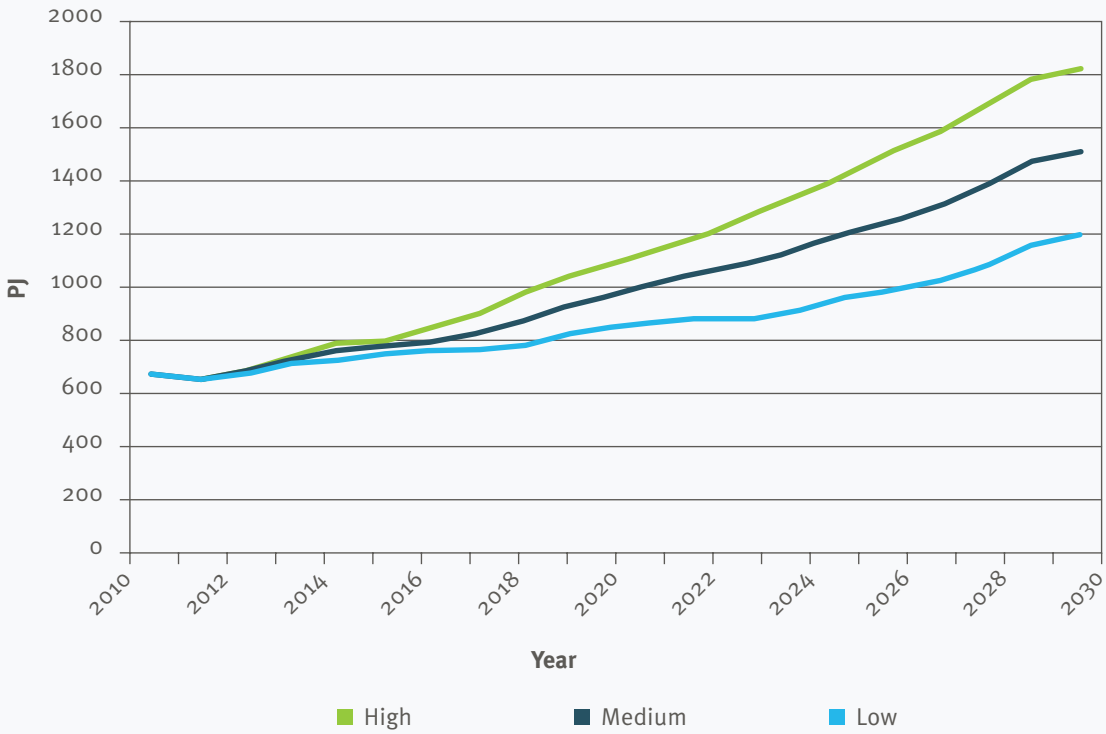



*Figure 8 Total demand projections for eastern Australia, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

## LNG export modelling outcomes

The volume of gas required for export is illustrated in Figure 9; projections assume that each million tonne of LNG requires 62.5 PJ of delivered gas. For the first five trains, the actual contracted capacity has been used. The remaining trains are assumed to be contracted at 4 Mtpa.

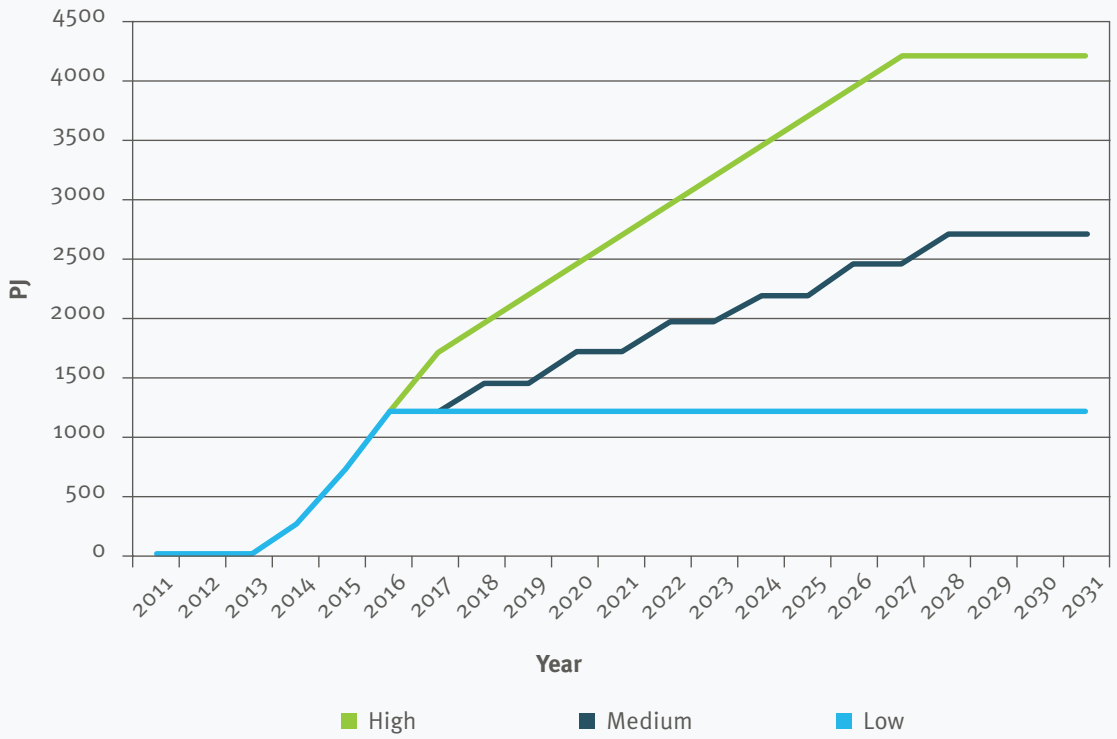



***Figure 9*** *Eastern Australia gas requirement for export, 2010–2030 (PJ/year)*

*Source: SKM MMA (2011)*

The 2P reserves commitments required to service these export projections are presented in Figure 10. The commitments are calculated on the basis that reserves sufficient to meet export deliveries for the life of the sales contracts are committed to the contracts at the time of contracting.

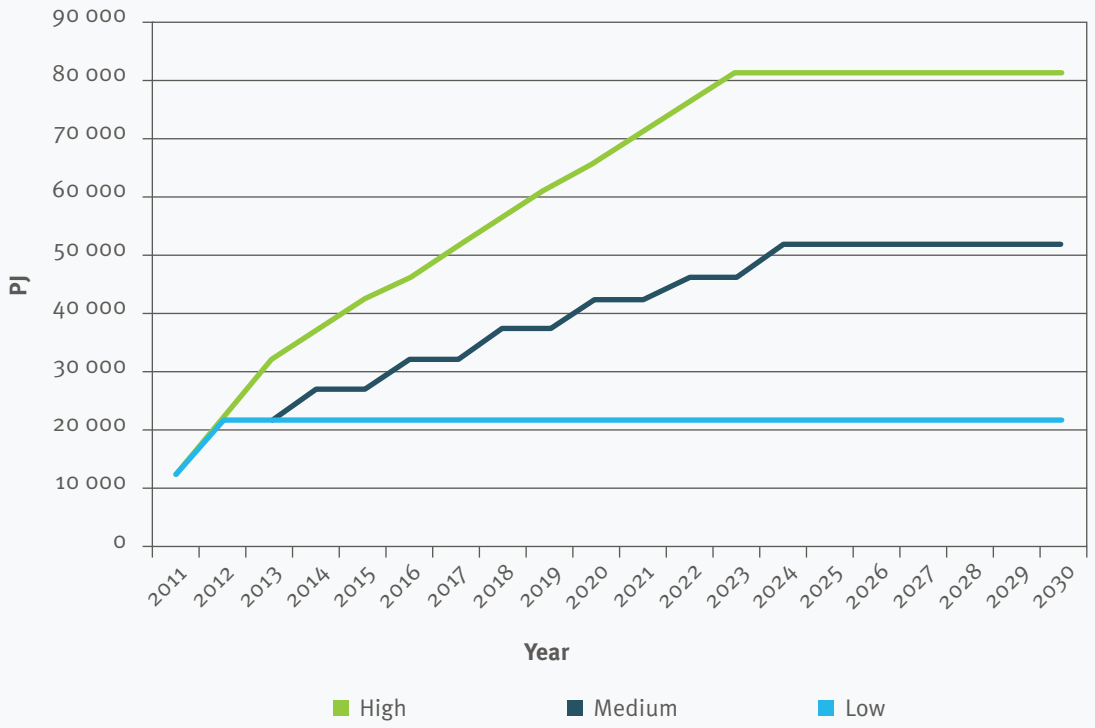



***Figure 10*** *Proved and probable (2P) reserves commitments for export, 2010–30 (PJ/year)*

*Source: SKM MMA (2011)*

## Timing of customer contracting

When graphed, demand appears as a straight line, but the underlying contracts reach term and require recontracting. This timing is critical for assessing market activity. Existing contracts reached a peak around 2008, which means in eastern Australia as a whole, there is a very high contract replacement requirement in 2018 due to the termination of contracts (primarily in Victoria).

Cumulatively the requirement for contracts for new loads exceeds the requirement for existing loads in the High and Medium scenarios; the requirements are approximately equal in the Low scenario. In Queensland, many GSAs reach term in the period 2015 to 2020 and require recontracting. The requirement for contracts for new loads exceeds the requirement for existing loads in all three scenarios as shown in Figure 11.

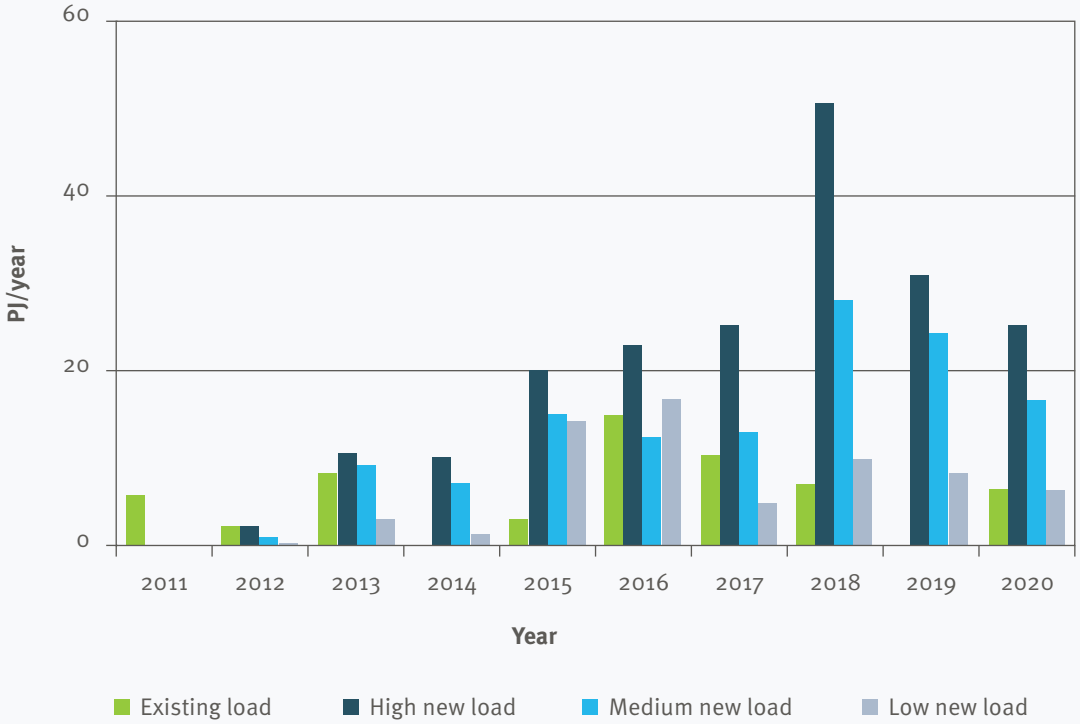



***Figure 11*** *Annual new contract requirements for existing and new loads to 2020, Queensland (PJ/year)*

*Source: SKM MMA (2011)*

The GSAs shown in Table 5 for eastern Australia include volumes estimated for related-party GSAs, which can be inferred but have not been publicly revealed. The table does not include any LNG-related arrangements. GSAs are compared with 2P reserves as at 31 December 2010.

# Gas reserves

Gas reserves form the basis of commercial contracting for supply of gas in the ground to customers. Reserves are classified as follows.

### *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

### *Sub-commercial contingent resources*

Demonstrated resources whose commerciality requires further assessment:

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

### *Prospective resources*

Inferred resources:

- low estimates
- medium estimates
- high estimates

This classification of reserves is consistent with that used by AEMO in the GSOO 2010 report (AEMO 2010a). The gas reserves and resources estimates used in the SKM MMA report which underpins the 2011 GMR incorporate the most recent reserves estimates published by Geoscience Australia and by the gas companies (Geoscience Australia 2009).

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 typically dedicated to contracts although, in some cases where 2P reserves are initially less than the total contract gas quantity, 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.

## 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 in 2008. For the eastern Australian gas market, total 2P reserves are estimated at 43 650 PJ. Table 6 provides a regional breakdown.

*Table 5 Eastern Australian 2P reserves (PJ) at 31 December 2011*

| 2P reserves | New South Wales | Victoria | Tasmania | South Australia | Queensland | Total |
|---|---|---|---|---|---|---|
| Conventional | 0 | 7 071 | 0 | 0 | 110 | 8 595 |
| | | | | 1 414* | | |
| CSG | 2 879 | 0 | 0 | 0 | 32 076 | 34 955 |
| Total 2P reserves | 2 879 | 7071 | 313 | 1 414 | 32 186 | 43 550 |

*Cooper–Eromanga Basin reserves have been allocated to the South Australian total for the purposes of this analysis.
*Source: SKM MMA (2011)*

The contingent and prospective gas resource is estimated at 202 991 PJ. Table 7 provides a regional breakdown.

*Table 6 Breakdown of eastern Australian contingent and prospective gas resources (PJ)*

| Contingent and prospective gas resource | New South Wales | Victoria | Tasmania | South Australia | Queensland | Total |
|---|---|---|---|---|---|---|
| Conventional | 0 | 8 654 | 0 | 0 | 429 | 12 058 |
| | | | | 2 975* | | |
| CSG | 68 375 | 0 | 0 | 0 | 122 558 | 190 333 |
| Total resource | 68 375 | 8 654 | 0 | 2 975 | 122 987 | 202 991 |

*Cooper–Eromanga Basin reserves have been allocated to the South Australian total for the purposes of this analysis.
*Source: SKM MMA (2011)*

Both 2P reserves and the contingent and prospective gas resource are weighted to the growth of CSG gas production. The location of reserves and resources is also weighted towards Queensland although New South Wales has a growing CSG resource that is not yet demonstrating a transfer to 2P reserves.

SKM MMA notes that since the 2010 GMR, 2C resources are approximately 2400 PJ lower, implying that in net terms approximately 27 per cent of the 8700 PJ of 2P reserves growth from 2009 to 2010 was derived by conversion of 2C resources. Consistent with this, the fall in 2C resources is in the Surat–Bowen Basin, where most of the reserves growth occurred. Prospective resources are approximately 10 000 PJ higher and this is entirely due to the addition of estimates for the Australia Pacific LNG and BG Group LNG projects.

Future conventional reserves additions in the modelling are based on the assumption that the contingent and prospective resources shown are converted to 2P reserves at a steady rate over a 30-year period, but it is noted that economic factors may lead to variations year-on-year in the rate of conversion.

Future growth rates for CSG 2P reserves are constrained by industry capacity to convert resources into reserves. Since the first LNG projects were announced in 2007, the project proponents have had a strong incentive to expand CSG reserves as quickly as possible. Table 8 shows the rapid increase in 2P reserves since 2007. This growth is taken to be indicative of the maximum capacity to expand the CSG reserves base within a set time frame.

*Table 7 Queensland CSG 2P reserves growth, 2007–2010 (PJ/year)*

| Queensland CSG 2P reserves growth | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|
| Total | 3 075 | 8 889 | 9 761 | 9 001 |

*Source: SKM MMA (2011)*

There are a number of areas where gas reserves may be declared in the future for which inadequate information is available at present. These include the Gunnedah and Galilee basins and areas for potential shale gas production. No provisions for future gas reserves from these areas have been included in the 2011 GMR modelling, but this will be reassessed year-on-year as the GMR is undertaken.

## LNG export reserves requirements

The 2P reserves commitments required to service the export projections are presented in Figure 12. The commitments are calculated on the basis that reserves sufficient to meet export deliveries for the life of the sales contracts are committed to the contracts at the time of contracting, which is assumed to be four years prior to first gas sales.

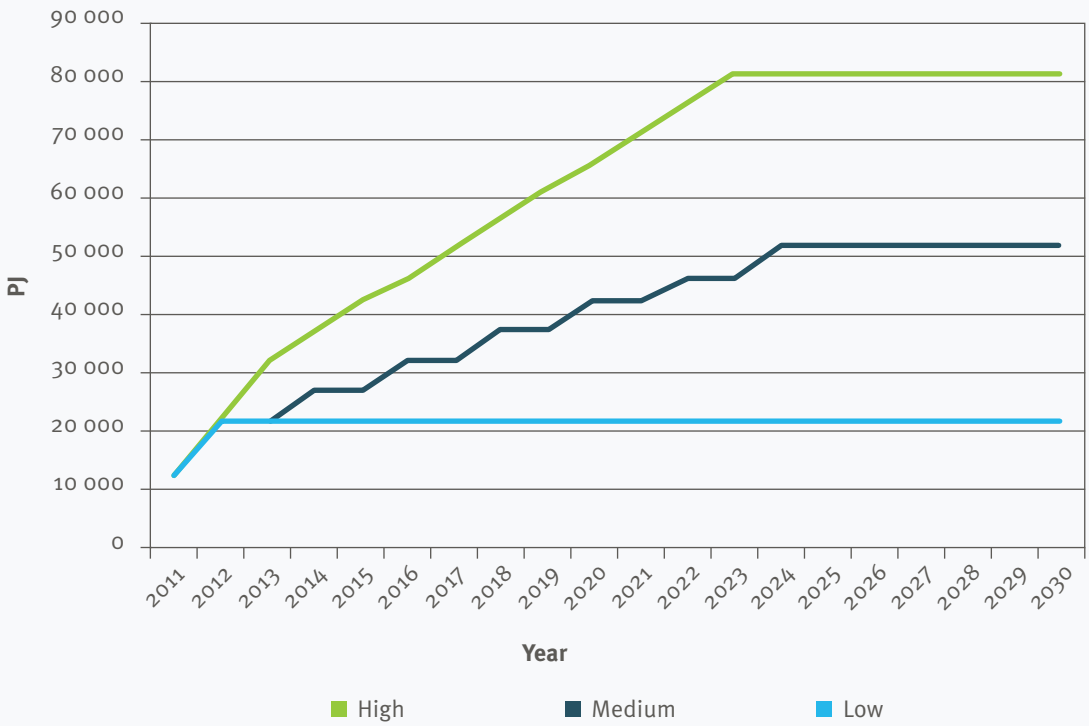



***Figure 12*** *Commitments of 2P reserves for export, 2011–2030 (PJ/year)*

*Source: SKM MMA (2011)*

As shown in Figure 12, the LNG projects will use substantial volumes of gas—approximately 220 PJ/year for each 3.5-Mtpa train. To put this in context, the annual volume of gas required by the four trains already committed (two each by BG Group and Gladstone LNG) will, when fully operational, equal the current eastern Australian demand. These volumes must be supported by 2P gas reserves equalling the volumes of gas committed to buyers in LNG off-take contracts, which typically have a term of 20 years. The committed projects therefore require approximately 17 600 PJ plus further margins for risk management. Additional trains or projects will add to this requirement.

## Domestic gas reserves requirements

GSAs are usually underpinned by 2P reserves. Existing GSA requirements can therefore be translated directly into requirements for gas reserves, noting contracting will be ahead of supply requirement by approximately three to four years. Reserves committed to existing GSAs in the eastern Australian market are shown in Table 9.

*Table 8 Comparison of 2P reserves and gas contracted as at 31 December 2010 in the eastern Australian market (PJ/year)*

| Basin | Joint venture | 2P reserves | | |
|---|---|---|---|---|
| | | Total | Contracted | Uncontracted |
| Conventional | | | | |
| Gippsland | BHP Billiton, Exxon | 5 210 | 1 914 | 3 296 |
| Gippsland | Nexus | 392 | 210 | 182 |
| Bass | Origin, AWE | 313 | 118 | 195 |
| Otways | BHP Billiton, Santos | 142 | 110 | 32 |
| Otways | Origin, others | 638 | 463 | 175 |
| Otways | Santos, others | 376 | 348 | 28 |
| Cooper Eromanga | Santos, Beach, Origin | 1 385 | 359 | 1 026 |
| Cooper Eromanga | Others | 29 | 0 | 29 |
| CSG | | | | |
| Sydney | AGL | 151 | 97 | 54 |
| Gloucester | AGL | 811 | 0 | 811 |
| Gunnedah | Eastern Star Gas/Santos | 1 520 | 0 | 1 520 |
| Clarence-Morton | Metgasco | 397 | 0 | 397 |
| Bowen | AGL/Arrow Energy | 1 810 | 279 | 1 531 |
| Surat | Australia Pacific LNG | 11 262 | 2 321 | 8 941 |
| Surat | BG Group | 8 200 | 851 | 7 349 |
| Surat | Gladstone LNG | 5 638 | 267 | 5 371 |
| Surat | Arrow Energy | 4 602 | 344 | 4 258 |
| Surat | Second tier | 664 | 35 | 629 |
| | Total | 43 540 | 7 716 | 35 824 |

*Source: SKM MMA estimates.*

Note: Surat and Bowen conventional reserves are omitted to avoid potential double counting.

Figure 13 illustrates the cumulative new domestic gas reserves requirements, assuming contract entry four years before first delivery. The projections are flat after 2026 because the underlying demand projections extend only to 2030.

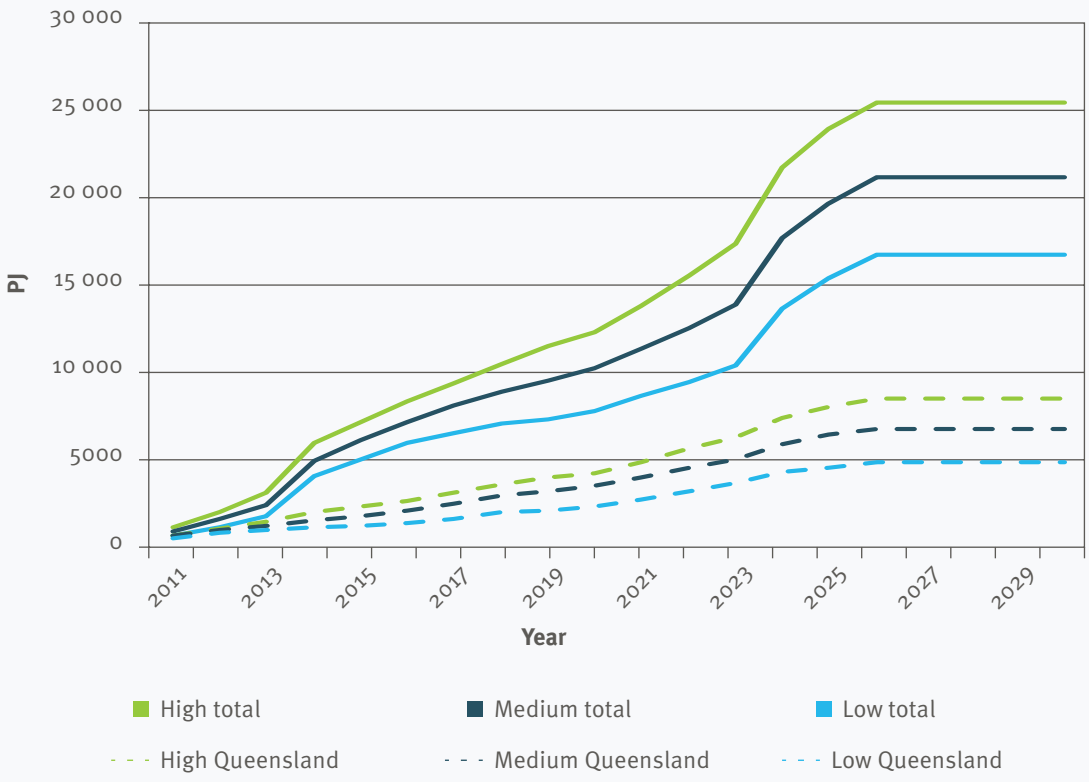



***Figure 13*** *Cumulative domestic gas reserves requirements, 2011–2030 (PJ/year)*

*Source: SKM MMA (2011)*

# Reserves modelling outcomes

## Economic scenarios

Physical shortfalls do not occur in any of the modelled economic scenarios. The modelling highlights that the aggregate reserve requirements for LNG export and domestic demand in the High economic scenario, with maximum reserves development, maintains a 2P reserves margin of approximately 30 000 PJ until 2020. If the High economic scenario result has reserves growth reduced in line with the Technical/Operational Impacts scenario, the reserves available remain at approximately 10 000 PJ from 2011 to 2017.

The requirements in the Medium and Low economic scenarios can also be met readily, with much larger margins extending into the long term, to the extent that reserves development at the maximum rate is unlikely to be required.

These margins will be maintained after 2020 only if there is continued growth of prospective resources feeding into contingent resources and reserves. Reserves currently excess to requirements would be available to service future expansion of LNG export capacity or the domestic market.

## Technical/Operational Impacts scenario

The picture is somewhat different in the Technical/Operational Impacts scenario, which focuses only on the period 2011 to 2015–16 and does not consider gas reserves and potential reserves that cannot be accessed due to lack of infrastructure from now to 2015.

Queensland domestic reserves requirements in this scenario are:

- in 2011, 622 PJ for domestic contracts and 1139 PJ for third-party LNG contracts (reflecting a projected deficit in LNG proponents' reserves owing to the impact of floods on reserves development)
- in 2012, 379 PJ for domestic contracts and 233 PJ for third-party LNG contracts.

In this outcome, total reserves available in 2011 are 1751 PJ and the total reserves requirement is 1761 PJ, leaving a small shortfall of 10 PJ. In 2012, the only reserves available would be 197 PJ due to reserves increases, assumed to be 97 PJ in the Cooper Basin and 100 PJ for the second-tier Surat–Bowen producers, against 612 PJ of reserves requirements. This would leave a substantial shortfall of 415 PJ or 425 PJ if the 2011 shortfall is accumulated. Regardless of the allocation of available reserves, both the domestic market and the third-party LNG purchasers would bear some of the shortfall.

Even if the constraint of weather and flood is assumed to apply only in 2010–11, the scenario demonstrates that access to reserves for contracting would be tight.

Since the start of LNG project development in 2007–08, project proponents have put considerable effort into reserves development; they have significant incentives to develop multiple train projects as quickly as possible to access economies of scale and construction cost savings for sequential train development on a single site. This also provides strong incentives not to sell incremental domestic gas contracts, which would require reserves dedication, until sufficient reserves have been appraised for the LNG projects. Non-proponent gas producers may also be disinclined to enter new domestic contracts for a period of time, until they can determine whether they will be able to sell some gas for export or until the domestic price response to exports becomes clearer.

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 exception was for shorter term contracts for ramp-up gas to 2014 to 2015.

This scenario demonstrates that an inability or unwillingness to supply gas for domestic GSAs is possible under circumstances that are plausible and aligns with customer feedback and reports of delayed appraisal programs.

Many existing large GSAs for major domestic customers in Queensland reach term in the period 2015 to 2020. New gas contracts will be required and these contracts must be underpinned by new reserves. For gas to be available for supply in this period, appraisals to develop domestic reserves need to be undertaken in the period 2011 to 2015. The Queensland Gas Commissioner is concerned that unless domestic appraisal plans are in place, or shortly put in place, available gas reserves may not be sufficient to underpin execution of new GSAs.

For efficient operation, the Queensland gas market requires clarity on the activities underway to develop gas reserves for domestic market use post-2015.

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 are supported by the modelling and analysis undertaken for the GMR. This indicates a tight reserves position as LNG projects prove up reserves to underpin LNG projects.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government seek detailed advice, confirmation and commitment from gas producers regarding the 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.

# Gas supply

An analysis of the projected aggregate gas supply outcomes for eastern Australia (including LNG export requirements) for the three economic scenarios shows the key aspects are:

- overall dominance of Queensland CSG production, which supplies most of the LNG exports
- strong growth in New South Wales CSG from the Gunnedah Basin, particularly in the High scenario
- a modest resurgence in Cooper Basin production owing to the sale of gas to Gladstone LNG
- modest growth in Gippsland Basin production
- declining production in the Otway and Bass basins owing to declining reserves
- in the High scenario, an overall decline in production at the end of the period owing to the rise in prices at that time.

The outcomes are shown in Figures 14 to 16.

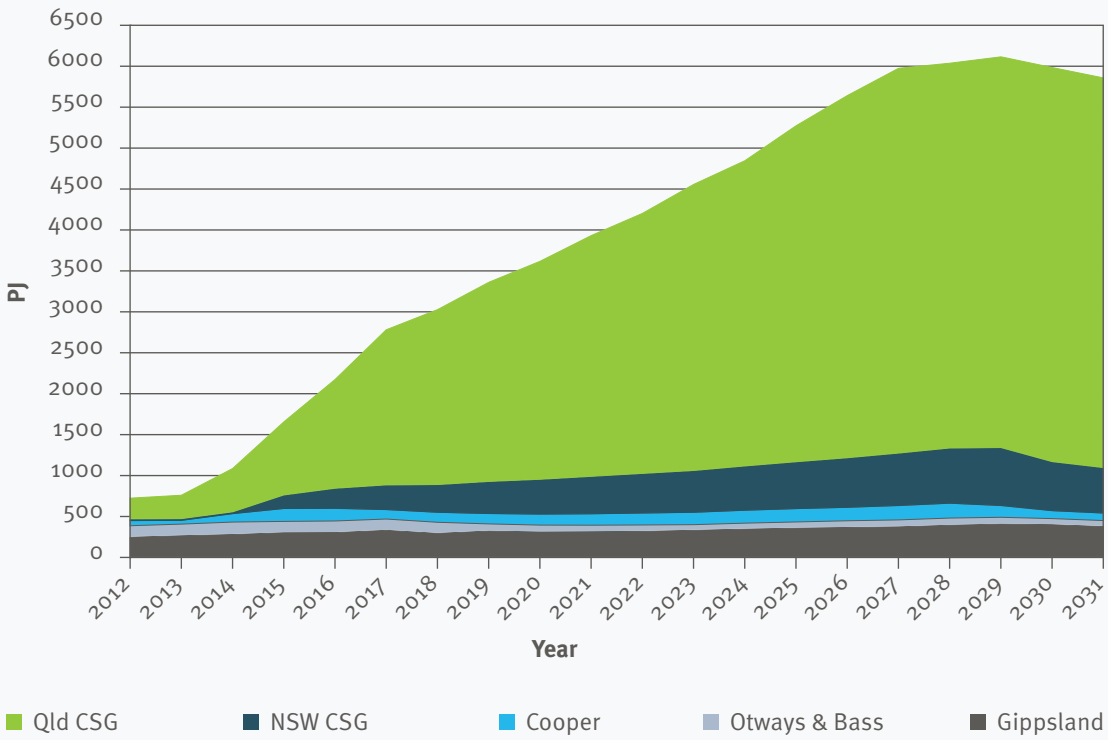



***Figure 14*** *Projected supply eastern Australia (domestic plus exports), High scenario, 2012–2031 (PJ/year)*

*Source: SKM MMA (2011)*

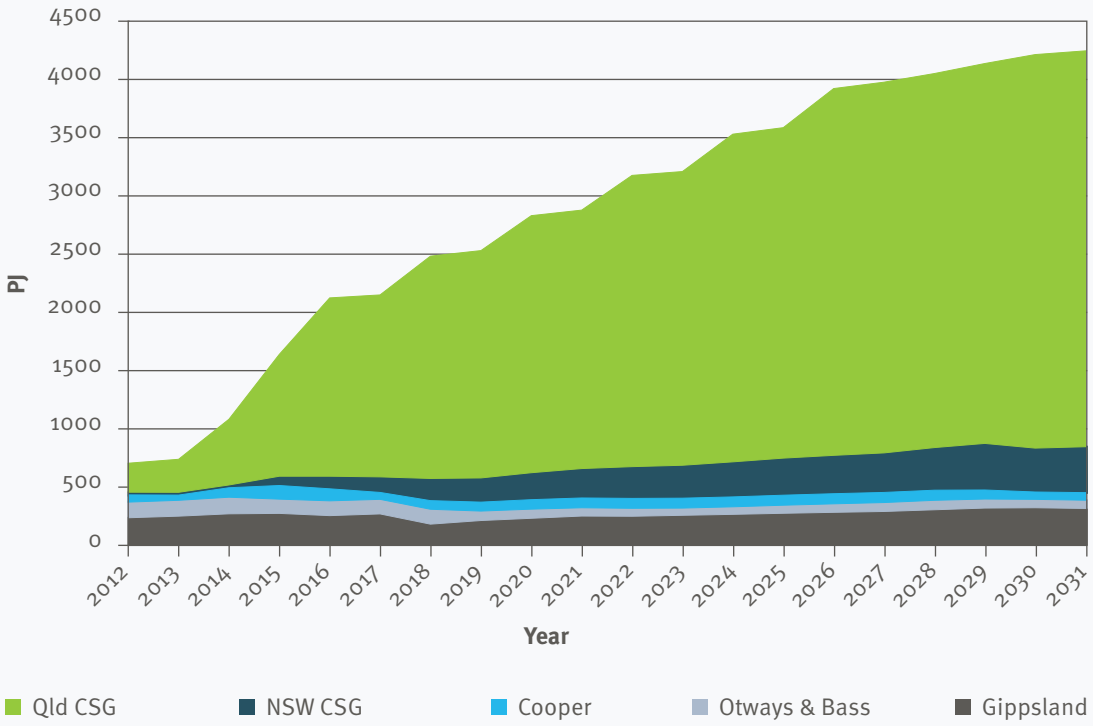



***Figure 15*** *Projected supply eastern Australia (domestic plus exports), Medium scenario, 2012–31 (PJ/year)*

*Source: SKM MMA (2011)*

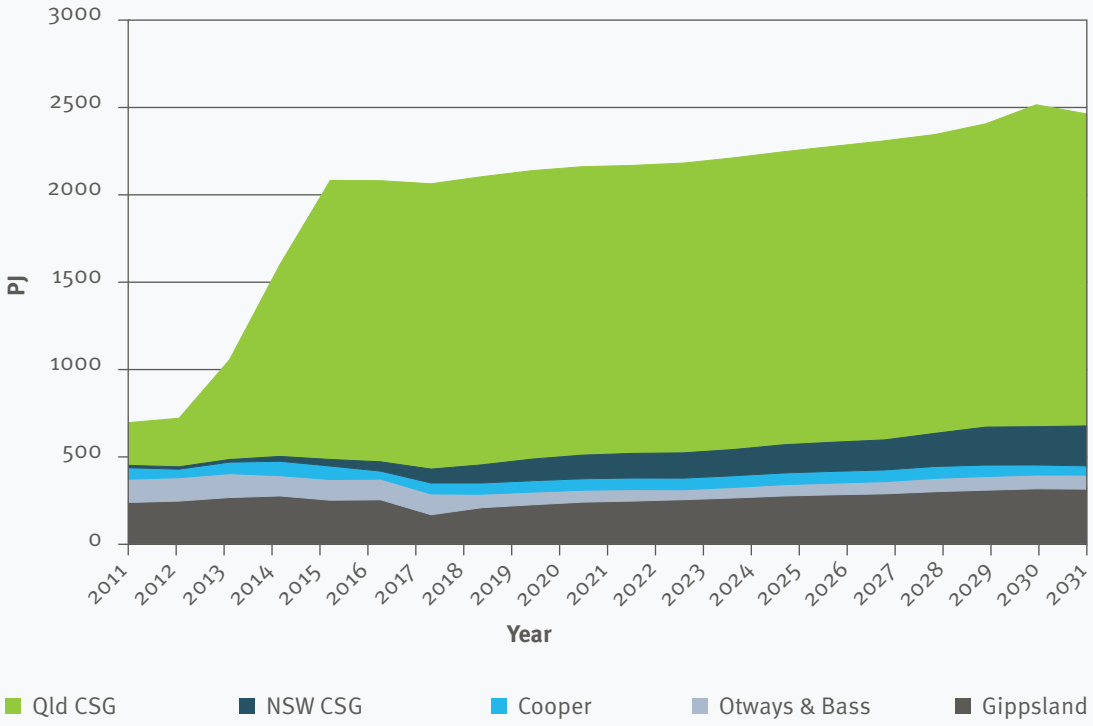



***Figure 16*** *Projected supply eastern Australia (domestic plus exports), Low scenario, 2012–31 (PJ/year)*

*Source: SKM MMA (2011)*

# Domestic gas pricing

Projected gas pricing is very sensitive to the scenario assumptions. All markets had very similar outcomes and these have been aggregated in Figure 17. This shows that:

- In the High scenario, new contract prices are expected to rise substantially from 2013, to over $8/GJ in most markets. This level is maintained until growth in LNG stops in the mid-2020s, at which point prices temporarily fall by $1–2/GJ, but then rise back to former levels owing to reserves depletion. The High scenario most closely replicates projections of LNG netback prices with oil price indexation.
- In the Medium scenario, new contract prices are expected to rise initially to approximately $6/GJ but then ease to $5/GJ as reserves growth outpaces growth in exports after 2018.
- In the Low scenario, new contract prices are expected to rise slightly up to 2016 but are otherwise expected to be more restrained.
- Ramp-up gas is included in initial contracts and is reflected in the declining average price in Queensland up to 2014.

Current market price expectations and behaviour indicate the High scenario is likely to eventuate. Market expectations of High scenario price outcomes could continue for some time after it becomes evident that a lower price scenario outcome is more likely. That is, it is possible for market prices to follow the High scenario for several years even though the Medium scenario eventuates. The price rises in this year's High scenario are higher than in the High scenario modelled for the 2010 GMR, largely because of the higher LNG projections. The price rises in the Medium and Low scenarios are very similar to those in the 2010 GMR.

Average contract prices follow the paths set by new contract prices, but with considerable lags, which also vary between markets because of differences in timing in the need for new contracts. The more unusual average price movements, such as the jumps in Brisbane and Mount Isa prices towards the end of the period, are due to a large price differential between new contracts and the ones they replace.


***Figure 17*** *New contract prices, Queensland aggregate, all scenarios, 2010–2030 ($/GJ, $2011 real)*

*Source: SKM MMA (2011)*

New contract prices in southern states are projected to rise slightly later than Queensland prices (Figure 18). Some of this delay is due to the more limited requirement for new contracts, especially in Victoria until 2018.

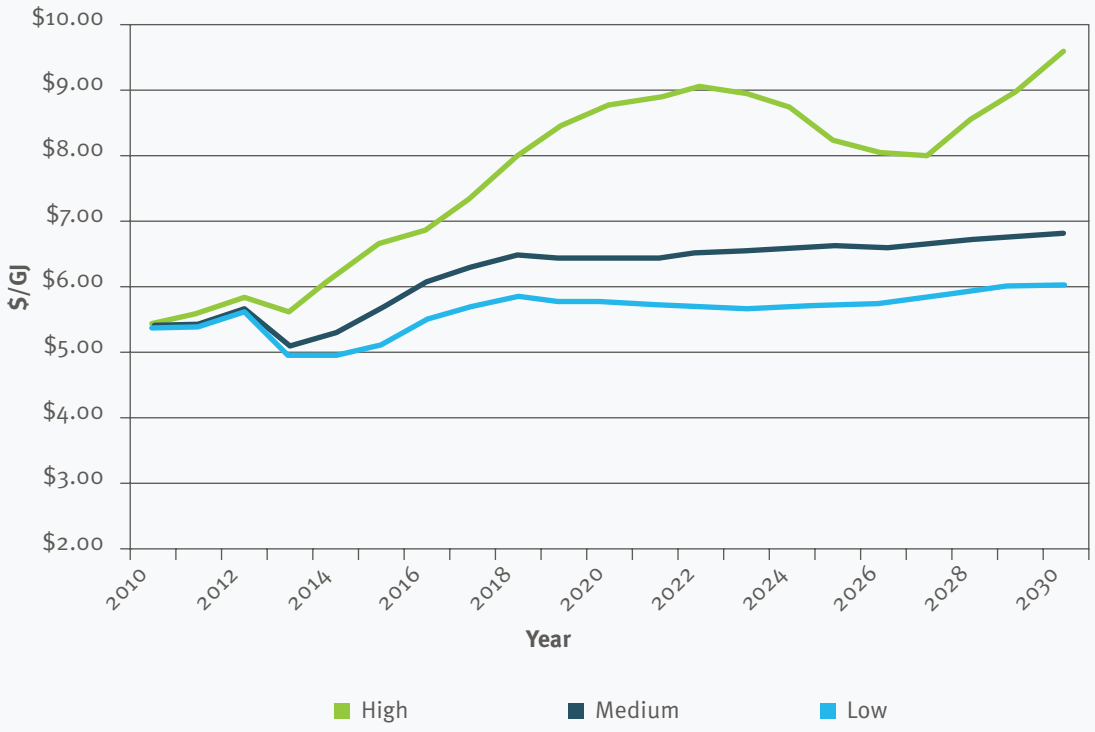



***Figure 18*** *New contract prices, southern states aggregate, all scenarios, 2010–2030 ($/GJ, $2011 real)*

*Source: SKM MMA (2011)*

# Market overview and issues identified

## Gas transmission pipelines

### Overview

Gas transmission refers to the transportation of natural gas via pipelines from gas production facilities to major users and markets. The four major interconnected natural gas transmission pipelines in Queensland are:

- Roma to Brisbane Pipeline (RBP) which runs from Wallumbilla (Roma) to Gibson Island in Brisbane and is owned and operated by the APA Group (APA)
- Carpentaria Gas Pipeline (CGP) which runs from Ballera to Mount Isa Pipeline and is owned and operated by the APA
- Queensland Gas Pipeline (QGP) which runs from Wallumbilla to Gladstone and Rockhampton and is owned and operated by Jemena Limited
- South West Queensland Pipeline (SWQP) which connects Ballera and Wallumbilla and is owned and operated by Epic Energy.

The QSN Link interconnects the SWQP with the Moomba to Sydney and Moomba to Adelaide pipelines.

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

### *Capacity demand*

Analysis and modelling suggests that each of the four major interconnected pipelines will face nearly static load factors (ratio of average daily load to peak daily load) over the next 10 years (Figure 19). This means that pipeline expansion in proportion to annual demand, in line with current load factors, will be sufficient to meet peak domestic market requirements over the next 10 years.

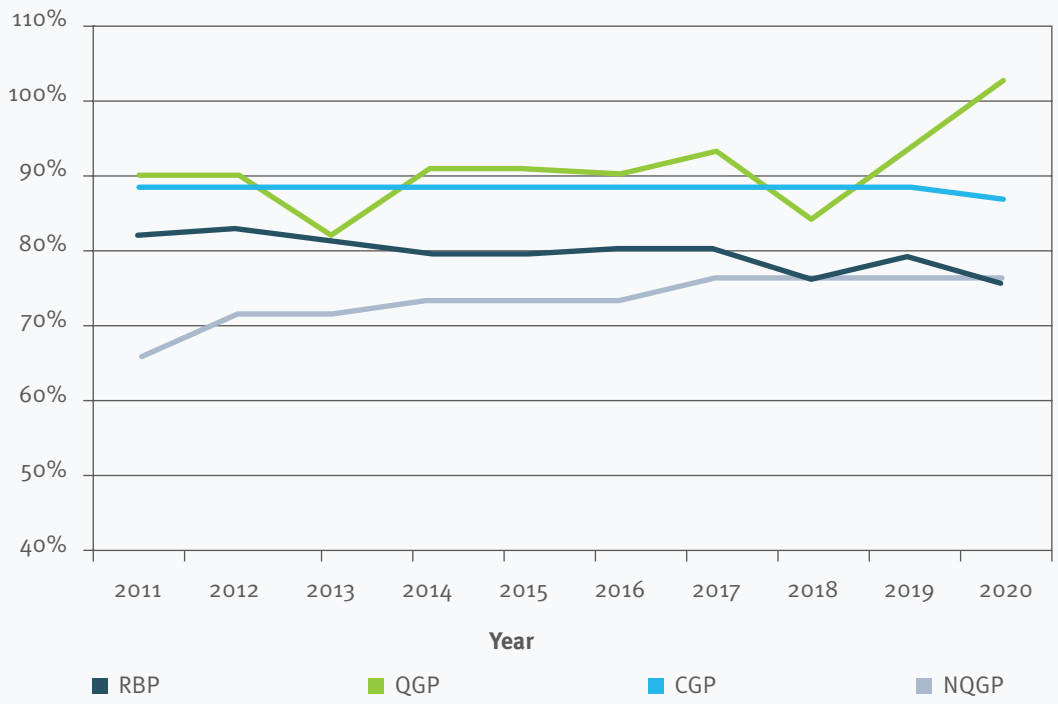



***Figure 19*** *Queensland gas pipeline load factors based on 1-in-2 peak demand, 2011–2030 (PJ/year)*

*Source: SKM MMA (2011)*

Note: RBP = Roma to Brisbane Pipeline; CGP = Carpentaria Gas Pipeline; QGP = Queensland Gas Pipeline; NQGP = North Queensland Gas Pipeline

Figure 20 compares the actual and estimated annual throughput volume of the four major interconnected pipelines and the QSN for the calendar years 2009 and 2010. Figures for actual flows were obtained from the National Gas Market Bulletin Board while estimated throughput is based on the output from the modelling using the three scenarios.

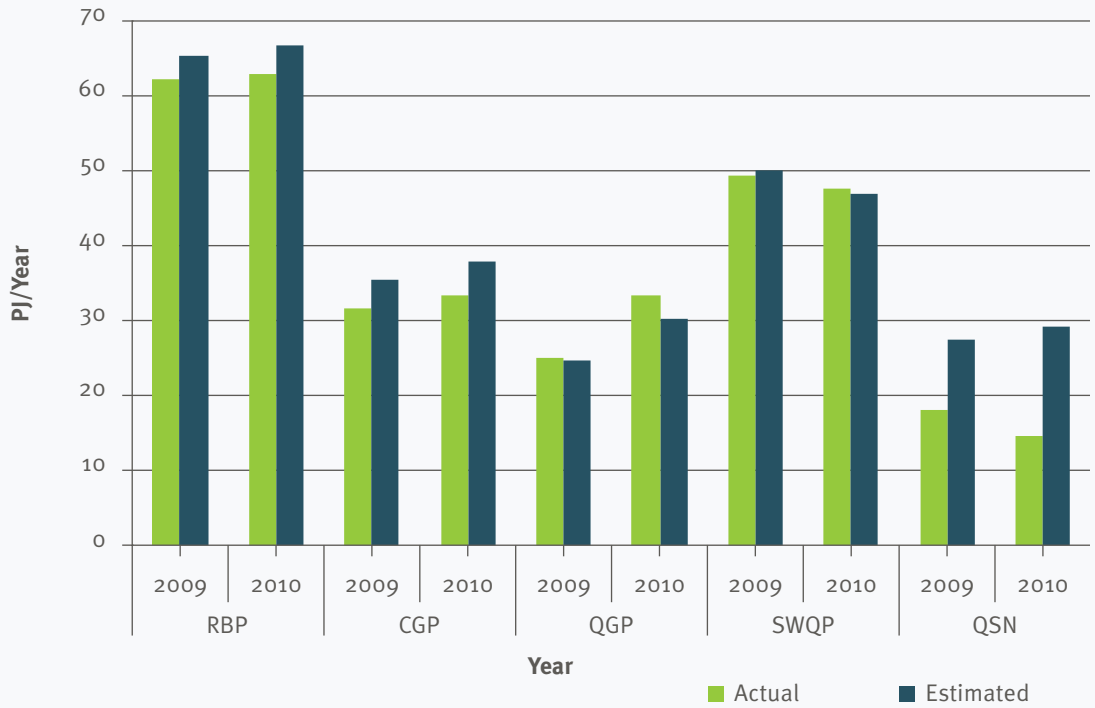



***Figure 20*** *Actual and estimated throughput of major Queensland pipelines, 2009 and 2010 (PJ/year)*

*Source: SKM MMA (2011)*

Note: RBP = Roma to Brisbane Pipeline; CGP = Carpentaria Gas Pipeline; QGP = Queensland Gas Pipeline; SWQP = South West Queensland Gas Pipeline; QSN = QSN Link Pipeline

## *Roma to Brisbane Pipeline*

Constructed in 1969, the RBP is 438 km in length and supplies major customers including Incitec Pivot (whose Gibson Island fertiliser plant was the first and underpinning RBP customer), CS Energy's Swanbank E Power Station, BP's Bulwer Island Refinery and energy retailers AGL and Origin Energy.

Opened in 1969, the RBP is Australia's oldest natural gas pipeline. Its capacity has been expanded a number of times and capacity is now more than five times the original capacity. The original pipeline is 41 cm (16 inches) in diameter and fully looped (duplicated) with the exception of the Brisbane metro section (running from Ellengrove to Murarrie). The duplicate pipeline is 25 cm (10 inches) in diameter and runs parallel from Wallumbilla to Ellengrove. Total RBP capacity currently is 80 PJ/year.

The RBP has seen much activity in recent years with additional capacity added in 2009. The remainder of this capacity was contracted in 2011 ahead of the commencement of the Brisbane STTM. In August 2010, APA completed an extension of the RBP by constructing a 6 km lateral from Murarrie to the Caltex refinery at Lytton. In April 2011, APA announced a $50 million capacity expansion of the RBP that will increase capacity by approximately 10 per cent and allow the operating pressure to be increased. The expansion involves looping a 6 km section of the remaining unlooped section of the pipeline from Murarrie to Gibson Island and the installation of a second compressor at Dalby.

APA advises there are currently 4 terajoules per day (TJ/d) of capacity at delivery points between Ellengrove and Gibson Island available to be contracted now for a service commencing on completion of the RBP expansion. There is a queue in place for this capacity. APA would need to determine on a case-by-case basis what spare capacity would be available to be contracted now for service delivery to points upstream of Ellengrove.

The expansion is scheduled to be completed in the second half of 2012. Once this expansion is complete, the section of pipeline from Murarrie to Ellengrove will be the only section not yet looped, offering opportunities for further expansion as incremental demand grows.

The STTM will commence operation in Brisbane in December 2011. An implementation project is currently underway and future STTM participants are amending their contractual arrangements to reflect new market operational procedures. The STTM values firm transmission capacity thereby sending appropriate signals for investment in infrastructure capacity. The recent contracting of available capacity and the current expansion of the RBP are timely and demonstrate the importance of clear market signals.

## *Modelling outcomes*

In all scenarios, Brisbane market demand for gas was low (1.2–1.6% growth). It is possible that a new pipeline such as one from the Clarence-Morton Basin could meet some Brisbane demand growth in the future, as a by-product of gas supply for GPG or LNG export. In the Medium and High scenarios SKM MMA projected that some Clarence-Morton Basin gas would be sold to LNG projects in Gladstone—this gas is assumed to be backhauled on the RBP from Brisbane to Wallumbilla without any capacity requirements. For the RBP, the three scenario outcomes (shown in Figure 21) are:

- In the High scenario, additional capacity may be required in the short term, starting now and peaking in 2017 at roughly 35 TJ/d extra. Peak demand is then projected to remain below capacity throughout the rest of the period.
- In the Medium and Low scenarios, peak demand declines from its 2011 value and remains below capacity throughout the rest of the period.

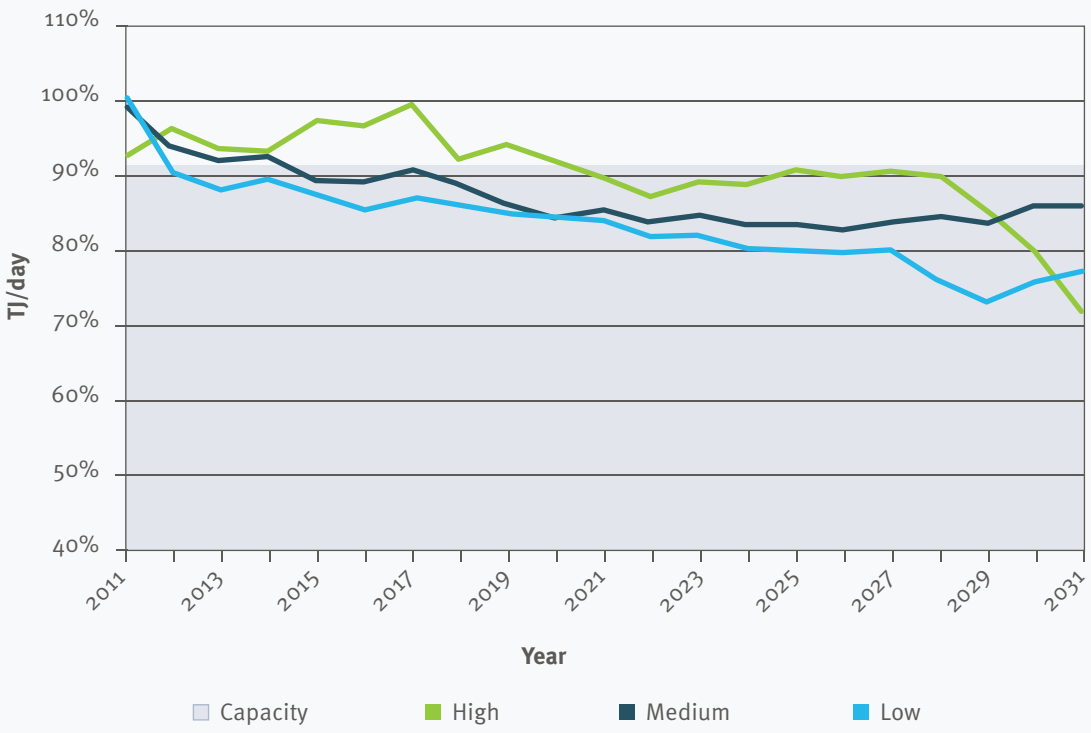



***Figure 21*** *Estimated peak flow and capacity for the RBP, 2011–2031 (TJ/day)*

*Source: SKM MMA (2011)*

## *Carpentaria Gas Pipeline*

The CGP is an 840 km pipeline that supplies customers in Mount Isa (via the 6 km town lateral) and the surrounding Carpentaria mineral province. The CGP began operations in 1998 and customers include the fertiliser plant at Phosphate Hill, the mine at Cannington (via the 96 km Cannington lateral) and the Mica Creek Power Station in Mount Isa.

APA completed expansions of the CGP in 2001 and 2009 by constructing the Morney Tank and Davenport Downs compressor stations, increasing capacity from the original 36 PJ/year to approximately 44 PJ/year.

APA reports there are currently 3 TJ/d of capacity on the CGP available for contracting at any of the delivery points. Additional future capacity expansion can be achieved by progressively installing additional compressor stations at scraper station sites along the pipeline.

### *Modelling outcomes*

No additional capacity is required in any of the three modelled scenarios. In the High scenario the load in Mount Isa is projected to fall owing to the connection of Mount Isa to the electricity transmission network. Figure 22 shows the projections of peak demand and capacity for the CGP.

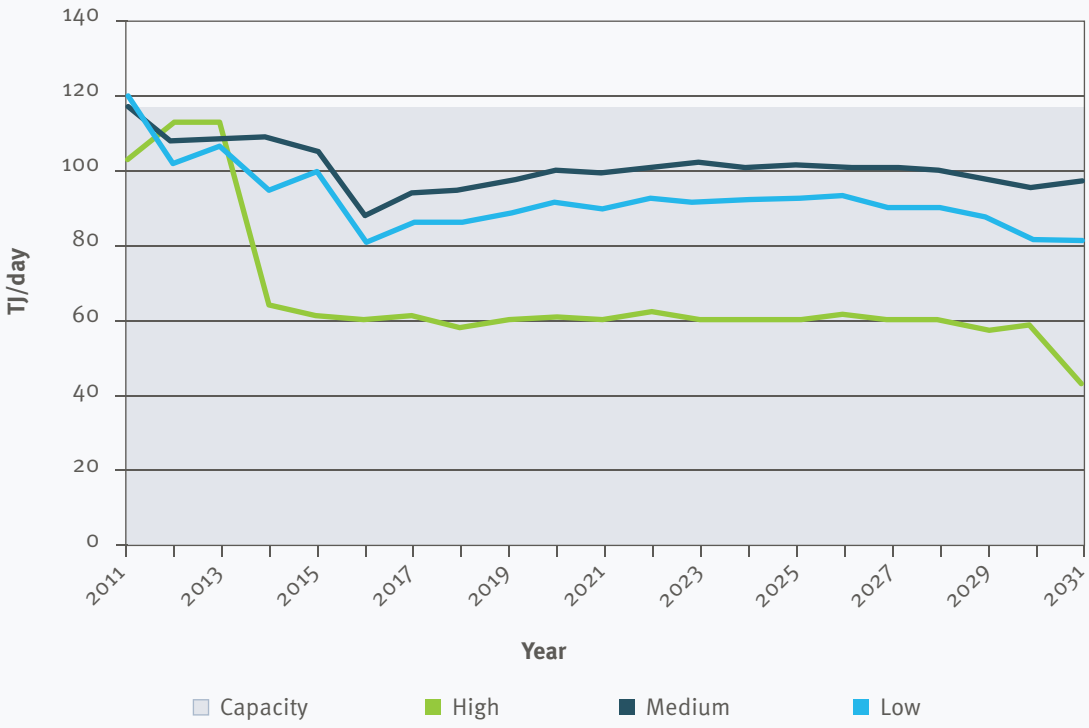



***Figure 22*** *Estimated peak flow and capacity for the CGP, 2011–2031 (TJ/day)*

*Source: SKM MMA (2011)*

## *Queensland Gas Pipeline*

The QGP is a 627 km gas transmission pipeline that supplies major users including Queensland Alumina Limited, Rio Tinto Aluminium, Orica, Boyne Smelters and Queensland Magnesia. Gas is also transported to the retail distribution networks in Gladstone, Rockhampton and Wide Bay.

The initial capacity of the QGP was expanded in 2010 from 30 PJ/year to approximately 52 PJ/year to meet the growing industrial demand for natural gas in Gladstone. The expansion involved looping an 11 km section of the QGP and installing additional compressors. The QGP is currently operating at close to full capacity, but Jemena, the owner, believes it may be capable of expansion to transport up to 180 PJ/year of gas supply.

### *Modelling outcomes*

The peak demands in each scenario broadly follow the trends in the demand projections. In the High scenario, some Gladstone demand is met by gas from the Moranbah production centre transported via the Moranbah–Gladstone Pipeline.

Some of the incremental capacity requirements after 2014 could be substituted by LNG project pipelines. It is noted that in March 2011, Jemena entered into an agreement with LNG Limited to undertake a feasibility study to investigate the potential of expanding the QGP to transport gas for LNG Limited's Fishermans Landing LNG project. Under the proposed expansion, gas would be transported from Wallumbilla to Callide, and then delivered to the project's site via a planned 20 km gas pipeline. Jemena expects the study to be completed in June 2011.

For the QGP, the scenario modelling outcomes are:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2012 and peaking initially in 2021 at roughly 100 TJ/day extra. Around 2026, there is a marked increase in the estimate of peak demand which reaches its highest level in 2027 with an additional 100 TJ/day. Demand then decreases towards the 2021 level by the end of the period. This is likely to be due to the assumption that the number of LNG projects stops at 17 trains, leading to a substantial amount of developing reserves becoming available to the domestic market.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2012 and peaking in 2022 at roughly 200 TJ/day extra. The peak demand is then estimated to be stable until around 2031 when it can be seen to increase again.
- In the Low scenario, additional capacity would be required at an increasing rate, starting in 2013 and peaking in 2016 at roughly 75 TJ/day extra. The peak demand is then estimated to be stable throughout the rest of the forecasting period (Figure 23).

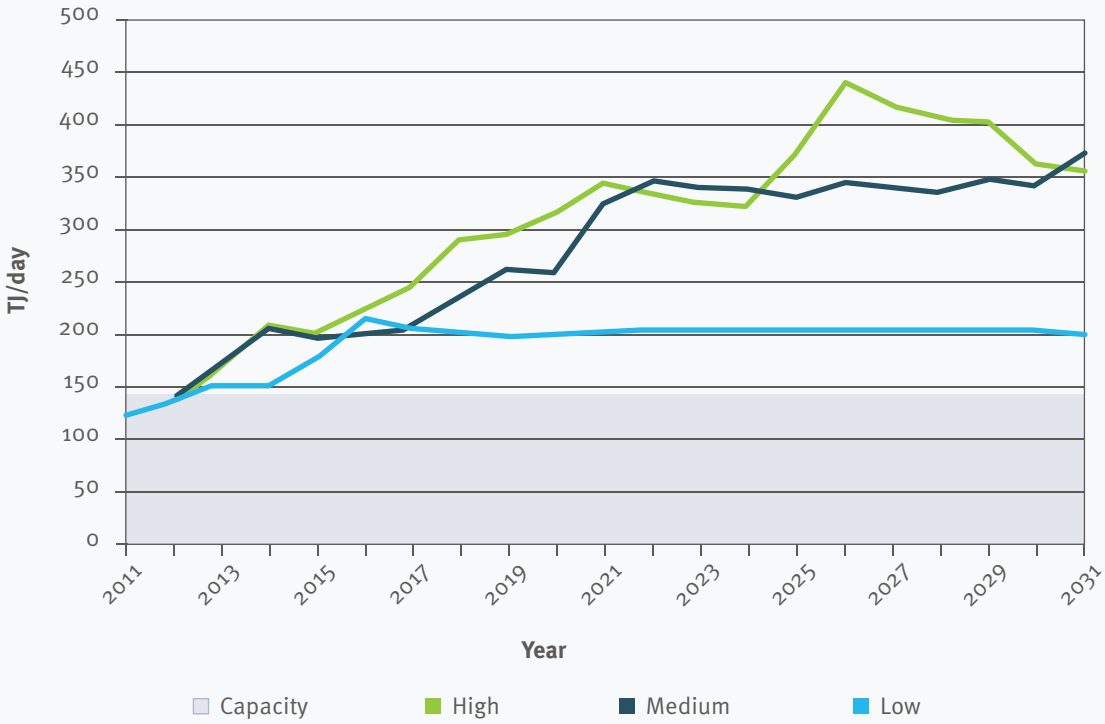



***Figure 23*** *Estimated peak flow and capacity for the QGP, 2011–2031 (TJ/day)*

*Source: SKM MMA (2011)*

## *South West Queensland Pipeline*

The SWQP is a 935 km pipeline that currently connects near Roma (Wallumbilla) and links to Ballera in south-west Queensland and Moomba in South Australia. The SWQP has a capacity of approximately 66 PJ/year. At Wallumbilla, the SWQP connects with the QGP to Gladstone and Rockhampton and the RBP to Brisbane.

The original SWQP ran the 756 km from Ballera to Wallumbilla. In 2008, it was expanded by compression from 47 PJ/year to the current 66 PJ/year and extended by 180 km to the current 935 km by the QSN Link, which provides a connection to the Moomba to Adelaide Pipeline System and the Moomba to Sydney Pipeline and southern gas markets.

In 2009, a project started to loop the entire length of the SWQP, including the QSN Link. This expansion is currently under construction and scheduled for completion in January 2012. The looping project will increase capacity from 66 PJ/year to approximately 142 PJ/year east to west and 128 PJ/year west to east. Capacity will vary according to

where gas is injected and withdrawn along the pipeline. The new capacity has been contracted for 25 years, but existing capacity that is currently contracted will begin to become available for re-contracting from 2015.

By 2014 the SWQP will be in the unusual situation of being bi-directional, that is physically able to flow gas either east to west or west to east on an approximate 24-hour turnaround. This will support the movement large volumes of gas to either the southern markets and Mount Isa or to Gladstone and Brisbane, as required.

Epic Energy believes that opportunities to further expand capacity can be economically implemented by adding compression.

### *Modelling outcomes*

The High scenario produces the lowest projections until around 2023 owing to the relative lack of Queensland CSG available for export to the southern states (Figure 24). After this time, the number of LNG projects is projected to stop at 17 trains, leading to a substantial amount of developing reserves becoming available to the domestic market. Much of this gas is exported to the southern states.

Under the Medium and Low scenarios, there are increased flows along the SWQP for the period 2017 to 2020. This is mainly caused by the rapid reserves development required for export from committed trains to 2016 (two per year), after which the rate of train start-up falls off causing the release of more Queensland CSG to the domestic market.

The modelling outcomes for CSG are:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2023 and peaking in 2030 at roughly 365 TJ/day extra.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2018 and peaking initially in 2020 at roughly 100 TJ/d extra. Another increase in flow leading to additional capacity requirement is expected from around 2024 to peak at the end of the period at roughly 326 TJ/day extra.
- In the Low scenario, except for 2019 and 2020, the SWQP is estimated to be at capacity for the period to 2030. Additional capacity of around 100 TJ/day would be required after 2030. For the years 2019 and 2020, around 50 TJ/day of extra capacity is required; however, there is a possibility that this does not lead to an expansion owing to the short-term nature of the requirement.


***Figure 24*** *Estimated peak flow and capacity for the SWQP, 2011–2031 (TJ/day)*

*Source: SKM MMA (2011)*

## *North Queensland Gas Pipeline*

The NQGP is a 392 km pipeline with a capacity of approximately 22 PJ/year that runs from Moranbah to Townsville. It transports approximately 13 PJ/year to Queensland Nickel Industries, Copper Refineries and Incitec Pivot. The remaining pipeline capacity is used to meet demand from the Townsville Power Station.

The NQGP is currently unconstrained, with capacity to support market growth in Townsville. Opportunities exist for future pipeline expansion through the addition of compression.

### *Modelling outcomes*

The modelled outcomes for the NQGP directly reflect the gas demand projections, apart from variations due to price adjustments (Figure 25). The determined capacity constraints for each of the three scenarios are:

- In the High scenario, additional capacity would be required from 2023 and increase throughout the rest of the period to around 30 TJ/day extra.
- In the Medium scenario, ignoring the one-year peak demand spike in 2020, expansion of around 10TJ/day would first be required around 2024.
- In the Low scenario, no additional capacity is required.


***Figure 25*** *Estimated peak flow and capacity for the NQGP, 2011–2031 (TJ/day)*

*Source: SKM MMA (2011)*

### *Proposed new transmission pipelines*

Four new Queensland transmission pipelines are planned to supply gas from the Surat Basin to Gladstone for LNG processing:

- The Queensland Curtis LNG Project pipeline has started preliminary work on the laydown site and construction of camp facilities.
- The Gladstone LNG (GNLG) pipeline has begun mobilisation and preliminary survey of the 420 km pipeline route to Gladstone.
- Australia Pacific LNG has submitted an initial advice statement to the Queensland Government.
- Arrow Surat Pipeline anticipates that construction of the pipeline will start in 2015–16.

A fifth pipeline is planned by Arrow (the Arrow Bowen Pipeline) to connect gas operations in the Bowen Basin to Gladstone via a 600 km pipeline. An initial advice statement has been submitted to the Queensland Government for this pipeline project.

## Issues identified

The initial capacity of the RBP, QGP, SWQP and CGP has been expanded, with more expansions either underway or planned. With five new pipelines under development to support growth of the LNG industry, investment in pipelines and major pipeline capacity expansions puts Queensland is in a very strong position.

Where major capacity expansions are required, these are being undertaken in a timely manner. However, there are issues with small volume capacity expansion, e.g. to underpin existing customer business expansion or to allow access for a new small gas user. In most cases, this is not being achieved in a timely manner. No speculative incremental capacity exists, so these customers must wait to piggyback a future large capacity expansion. This effectively denies these customers access to the pipeline in a timely manner.

Pipeline owner-operators express a desire to allow a reasonable volume for further incremental growth when undertaking a major capacity expansion. Customers also seek this outcome. Pipeline owners indicate it is difficult to invest in incremental capacity under the current provisions of the National Gas Law. To address this issue, a review of the relevant sections of the legislation would be required.

It is acknowledged that many factors play into successful investment in pipeline capacity expansions, including current global finance and investment market issues and infrastructure owners' appetite for capacity risk. Nevertheless, there appears to be the potential for a category of customer to be excluded from timely purchase of pipeline capacity due to their volume requirements. To address this issue, a review of this section of the national legislation would be required.

Pipeline owner-operators and customers have expressed concern that national legislative provisions discourage investment in uncontracted capacity when pipeline expansions are being undertaken.

### *Recommendation*

The Queensland Gas Commissioner recommends the government act through the appropriate jurisdictional forum/s to raise the issue of incremental pipeline capacity expansion for review.

## Gas distribution networks

### Overview

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 two major gas distribution businesses—APA Gas Networks and Origin Energy. In Brisbane, the APA network services south Brisbane, including the Gold Coast, while the Origin Energy network services north Brisbane. These companies also operate small distribution networks 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 governments.

There are approximately 165 000 customers on Queensland gas distribution networks; around 95 per cent of these are residential users. Average residential consumption in Queensland is currently about 9–10 GJ/pa. This is down from the 11–12 GJ/pa of earlier years. By comparison, in Victoria average annual residential consumption is 55 GJ/pa and in New South Wales consumption is 21 GJ/pa, with the primary difference being household winter heating.

Gas distribution networks in Queensland continue to increase overall customer connection numbers. However, overall gas use is declining, reflecting the impact of competition from other fuel sources and improved appliance and operational efficiencies.

The primary gas use underpinning residential load is gas hot-water heating. The new generation of gas hot-water services is more efficient and can reduce household use by up to 2 GJ/pa. Gas hot-water heating also faces strong competition from solar and heat pump appliances. In addition, overall household water consumption in South East Queensland dropped during the recent drought and has not returned to pre-drought levels. Lower water use equates to lower hot-water use and this is reflected in a reduction in gas consumption for water heating.

The already small residential heating requirement in Queensland continues to face competition from electricity, particularly from reverse cycle air-conditioning. This has seen a net reduction in gas use in the few areas (e.g. Ipswich and Toowoomba) that have traditionally had a gas heating load.

In the commercial and small industrial sector, volume is expected to grow slowly but steadily at 1.1 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 year.

### Issues identified

Distribution network owners expect the downward trend in average residential consumption to continue, while connections continue to grow at around 3–4 per cent. In this environment it will be difficult to grow gas use in the residential sector.

The commercial and small industrial sector also faces fuel competition, with coal continuing to be used as a fuel by customers who have access to gas. Coal use has dropped over the years, but it is understood that continued coal use equates to several petajoules per year of gas use. Little work has been done in this area, but it offers some potential to increase gas consumption on the distribution networks and improve use of the infrastructure.

The use of coal as a fuel in areas served by gas distribution networks has dropped over the years, but coal remains a competitor to increased gas uptake in the commercial gas customer sector.

#### *Recommendation*

The Queensland Gas Commissioner recommends that 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.

## Short Term Trading Market

### Overview

The STTM is currently being established in Brisbane, with an AEMO project team managing implementation. A market trial is scheduled to start in September 2011, with market commencement scheduled for December 2011.

### Issues identified

The gas markets of Sydney, Adelaide and Brisbane and the design of the STTM reflect the interaction of gas retailers and users operating on, or in close proximity to, the capital city gas distribution networks; this is demand based.

Currently, in New South Wales and South Australia, the bulk of gas market demand is located on the capital city gas distribution networks or in close proximity to the capital cities. The Queensland situation is quite different. Brisbane is one of four gas markets in Queensland and is separated from the other three market—Mount Isa, Gladstone and Townsville—by large distances.

Although each has different market characteristics, they have a number of things in common, including a small number of large gas customers who take gas directly from the gas transmission pipeline and the consequent lack of significant distribution networks.

In addition to the gas markets, Queensland has a significant gas production industry that is growing rapidly to support the development of LNG. The growth in gas production is centred in the Surat Basin around Wallumbilla where three major gas transmission pipelines interconnect and four new pipelines are planned.

Once the two committed LNG projects (four trains) are fully operational after 2015–16, the annual volume of gas required by the projects will equal the current eastern Australian gas market consumption. Demand in Queensland will exceed 1000 PJ/year.

Balancing a large gas market and gas supplies to large LNG plants will require trading among LNG participants and other gas producers and users. This trading should be visible to the market and supported by market structures. The period from now to 2015 offers a timely opportunity to design, develop and implement a supply-based trading market to:

- encourage gas trading
- improve market liquidity
- improve trading and price transparency
- help gas producers manage variations in production capability and market and customer demand
- help customers who can manage a level of supply variability to trade gas to reduce overall gas supply costs
- underpin investment in transmission pipeline interconnections.

During consultation for the 2011 GMR, stakeholders indicated strong support for the development and implementation of a supply-based trading market at Wallumbilla. Given that LNG production will start from 2015, it would be desirable for the supply-based trading market to be operational by 2015 at the latest.

Stakeholders have indicated strong support for the development of a supply-based trading market centred in the Surat Basin around Wallumbilla (Roma) which would support market trading of produced gas and commencement of LNG production from 2015.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government continue to work through the Standing Council for Energy and Resources (SCER), the gas market reform process and with stakeholders to settle a design for a supply-based trading market for implementation by 2015.

The market developments in Queensland and a potential supply-based trading market offer a timely opportunity to work with other jurisdictions to underpin investment in transmission pipeline interconnections and lever the benefits of a supply-based trading market.

### *Recommendation*

The Queensland Gas Commissioner recommends that the government consider opportunities to work with the New South Wales Government and industry to facilitate the development of improved gas infrastructure interconnections and lever the market benefits of a supply-based trading market.

# Gas storage

## Overview

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.

Natural gas can be stored in three ways—in transmission pipelines as linepack, as LNG and in underground storage reservoirs. Most dedicated gas (non LNG) storage facilities are developed from depleted gas or oil fields, but natural aquifers and salt caverns are also used.

The increased sophistication and traded volume of Australian gas markets has seen the use of dedicated sales gas storage grow, although capacity remains low and use is not widespread. The demand for gas storage facilities and services is likely to increase in Australia as the state gas markets expand trading capability and become more interconnected. Gas storage at major supply intersections such as Wallumbilla can reinforce the ability to trade gas.

### *Gas storage currently in place*

There are currently three major gas storage facilities in the east coast Australian gas market—the Iona underground gas (20 PJ) and Dandenong LNG (0.66 PJ) storage facilities in Victoria and the Moomba underground (85 PJ) gas storage in South Australia.

In Queensland, small gas storage capability exists at the Chookoo field (2 PJ) in south-west Queensland and at the Newstead gas field (2 PJ) at Kincora near Roma. AGL is currently developing an underground gas storage facility (approximately 46 PJ) at the Silver Springs gas field south of Roma.

## Issues identified

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. To date, the size and complexity of the gas market in Queensland has not required large-scale commercial dedicated gas storage. The legislation therefore does not seek to regulate the safe operation of such facilities.

In an evolving and rapidly growing and maturing gas market such as Queensland's, the development of dedicated commercial natural gas storage facilities can provide flexibility for both producers and customers. Gas storage can also support competitive market trading and enhance security of supply for export and domestic customers, including gas-fired generation.

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 or tenure type or location.

### *Recommendation*

The Queensland Gas Commissioner recommends 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.

# Retail market

## Overview

The retail market for gas in Queensland is based on the distribution networks. 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

Maranoa Regional Council (previously Roma Regional Council) and Western Downs Regional Council (previously Dalby Regional Council) also operate small distribution and retail businesses.

The final stage of deregulation (full retail competition, or FRC) in the Queensland retail gas market was undertaken in 2007 when small customers were given the choice of retailer. AGL, Origin Energy and AP&G are active in the Queensland retail market. AP&G is a new entrant since deregulation, but services only a small number of customers. The majority of customers are serviced by AGL and Origin Energy.

While there is no impediment to customers changing retailers, the retail gas market is small and, in a market sense, in its infancy and there currently appears to be low levels of customer churn.

There is potential for additional new entrant retailers and improved competition with the commencement of the STTM in Brisbane. The STTM also offers larger retail customers the opportunity to purchase gas from the STTM as a further supply option.

The Ministerial Council on Energy (MCE) and the Queensland Government, who have implemented the national gas market reform process, have publicly stated clear objectives for the STTM that include enhanced gas market competition and improved transparency, particularly in relation to pricing—to the benefit of customers.

## Issues identified

It has come to the attention of the Queensland Government during 2011 that retail activity in the Brisbane market included actions seeking to preclude customers from buying gas directly through the Brisbane STTM. A letter was sent to all holders of a General Retail Authority to retail gas in Queensland, the Energy Retailers Association of Australia and the Energy Users Association of Australia advising of concerns on the matter and requesting that any such activity cease. Customers were encouraged not to accept constraint of their gas purchasing options through the STTM and consider accessing new gas market mechanisms and improvements that could benefit their businesses.

No supply or demand issues were identified for the Queensland retail gas market during consultation for the 2011 GMR.

# 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 |
| APLNG | Australia Pacific LNG |
| bbl | Barrel |
| bcf | Billion cubic feet |
| CGP | Carpentaria Gas Pipeline |
| CNG | Compressed natural gas |
| CNPC | China National Petroleum Corporation |
| CPI | Consumer Price Index |
| CSG | Coal seam gas |
| EIS | Environmental impact statement |
| ESOO | Electricity Statement of Opportunities (AEMO) |
| EUAA | Energy Users Association Australia |
| FEED | Front-end engineering and design |
| FID | Final investment decision |
| GJ | Gigajoule |
| GMR | Gas Market Review |
| GLNG | Gladstone LNG |
| GPG | Gas power generation |
| GSA | Gas sales agreement |
| GSOO | Gas Statement of Opportunities (AEMO) |
| HoA | Heads of agreement |
| HQCEC | Huanqiu Contracting and Engineering Corporation |
| JCC | Japan Customs-cleared Crude / Japan Crude Cocktail |
| LNG | Liquefied natural gas |
| MAOP | Maximum allowable operating pressure |
| MCE | Ministerial Council on Energy |
| mmbtu | One million BTU (British thermal units) |
| MoU | Memorandum of understanding |
| Mtpa | Million tonnes per annum |
| NEM | National Electricity Market |
| NQGP | North Queensland Gas Pipeline |
| PGPLR | Prospective Gas Production Land Reserve |
| PJ | Petajoule |
| QCLNG | Queensland Curtis LNG |
| QGP | Queensland Gas Pipeline |
| QSN | QSN Link Pipeline |
| RBP | Roma to Brisbane Pipeline |
| SEQ | South East Queensland |
| STTM | Short Term Trading Market |
| SWQP | South West Queensland Pipeline |

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