



2011 Gas Market Review Queensland



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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.

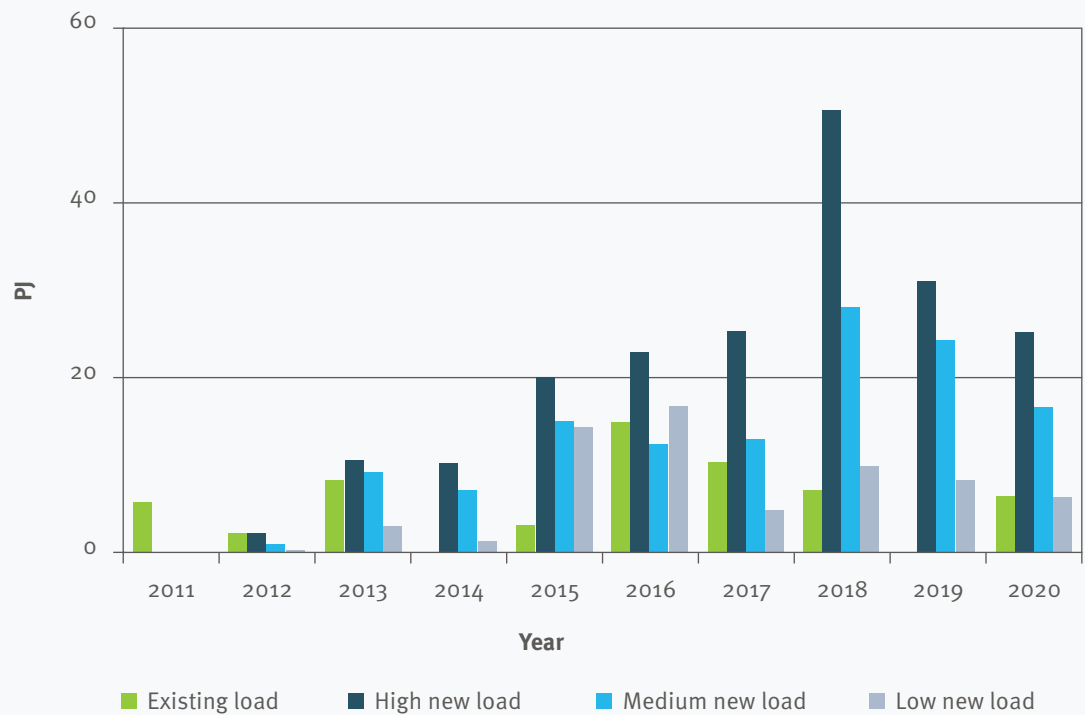


Figure E1 Annual new contract requirements for existing and new loads, Queensland, 2011–2020 (PJ/year)

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.

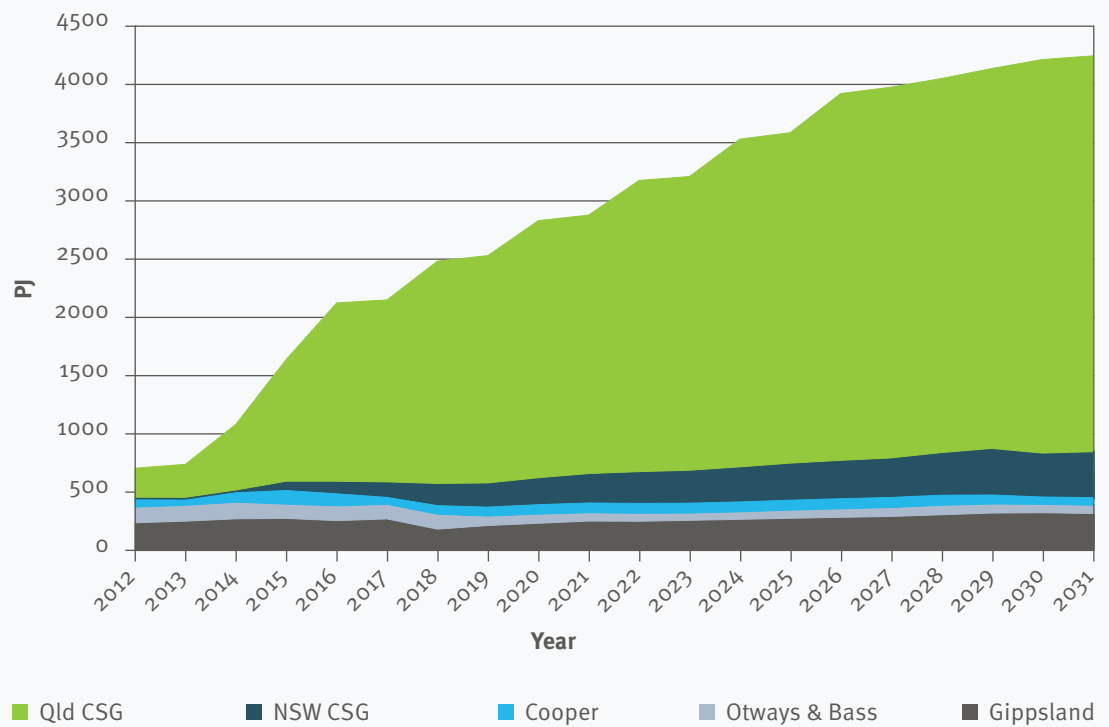


Figure E2 Projected supply eastern Australia (domestic plus exports), 2012–2031, Medium scenario (PJ/year)

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.

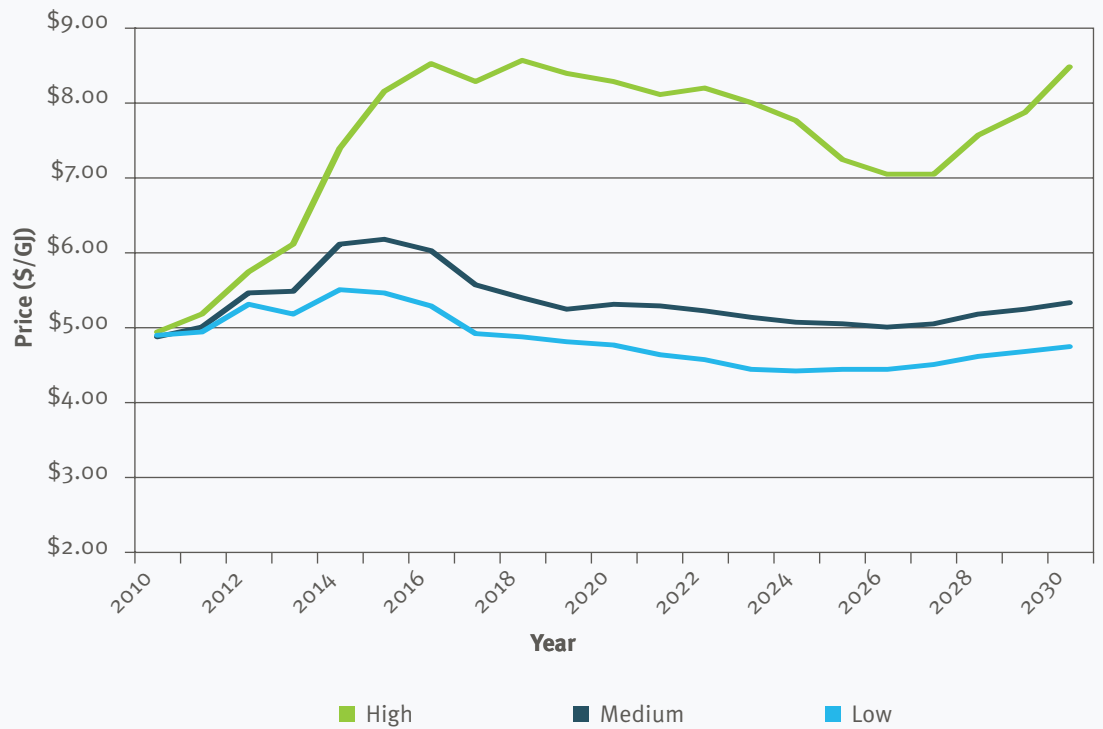


Figure E3 New contract prices, Queensland aggregate, 2010–2030, all scenarios (\$/GJ, \$2011 real)

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

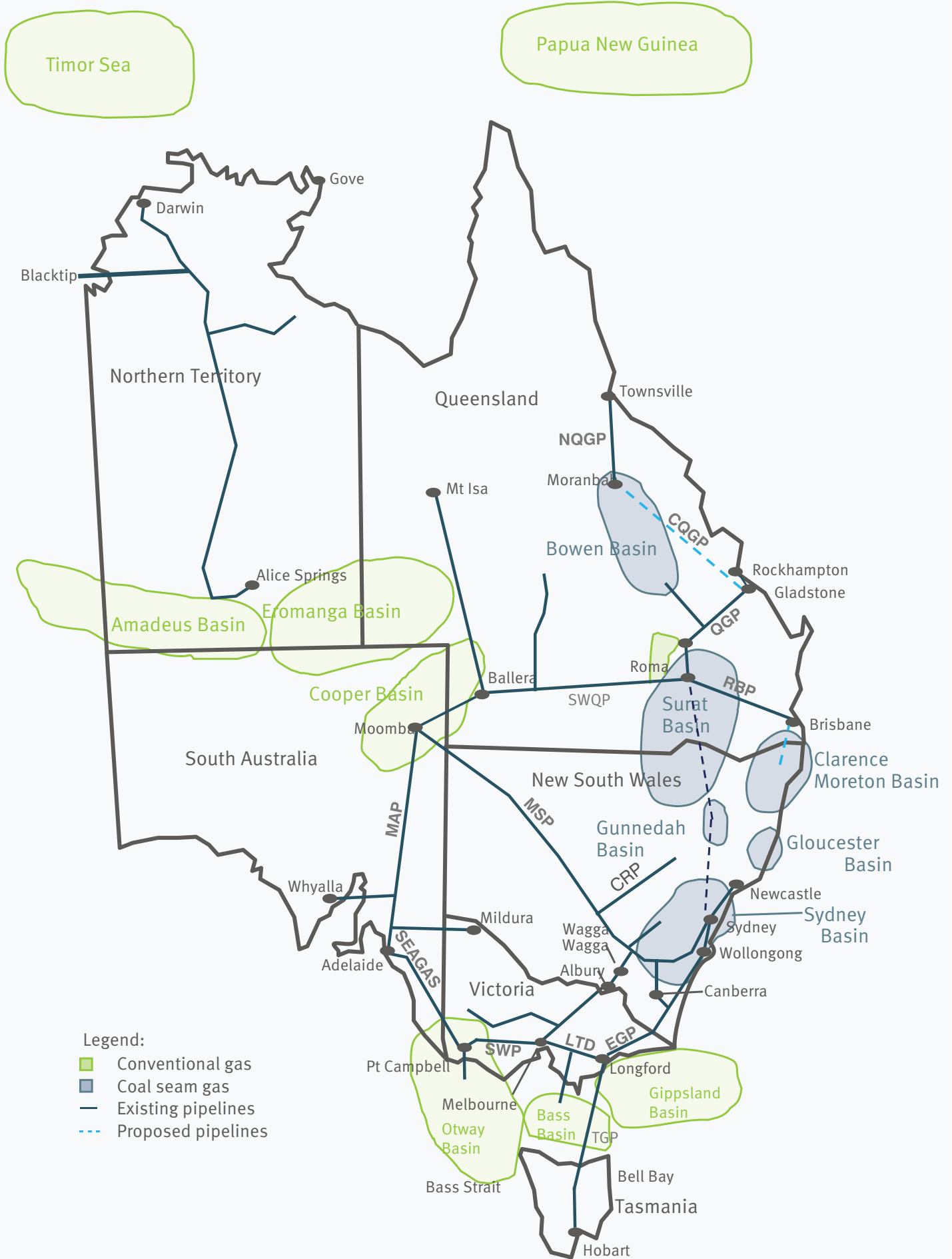
The uses of gas are many and varied. Gas is used in Queensland as a residential fuel primarily for water heating but also to fuel stoves, ovens and clothes dryers. Gas is also used as an ingredient to make fertilisers, antifreezes, plastics, pharmaceuticals and fabrics and to manufacture a wide range 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.





Legend:

- Conventional gas
- Coal seam gas
- Existing pipelines
- - - Proposed pipelines

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.

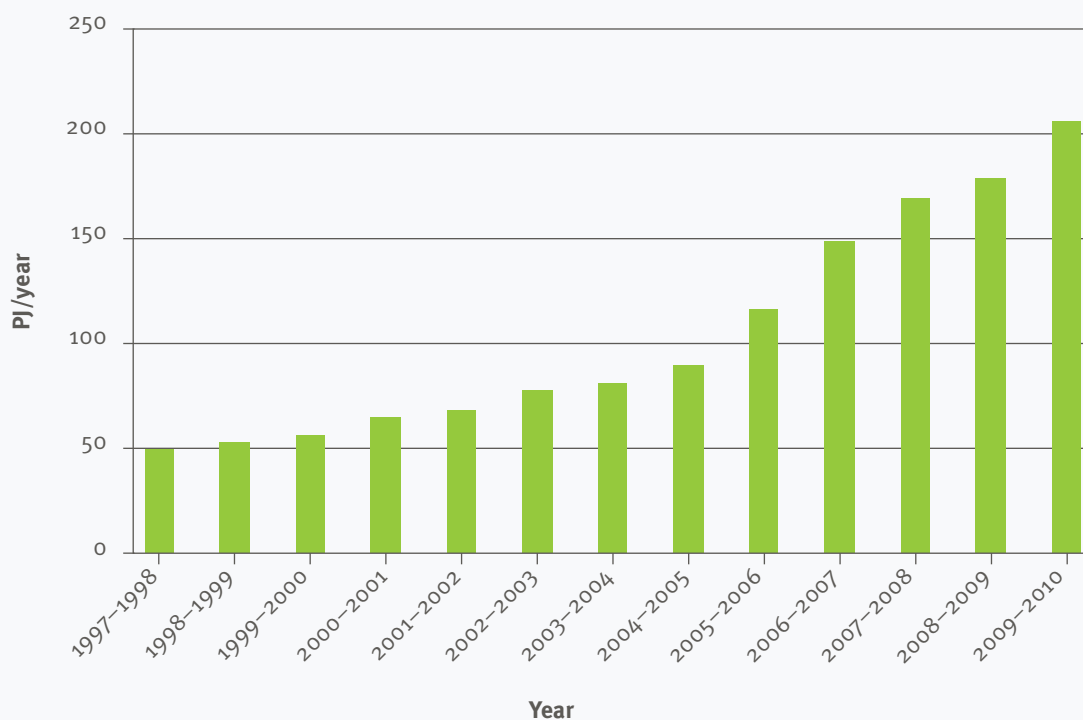


Figure 1 Queensland gas demand, 1997–2010 (PJ/year)

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.

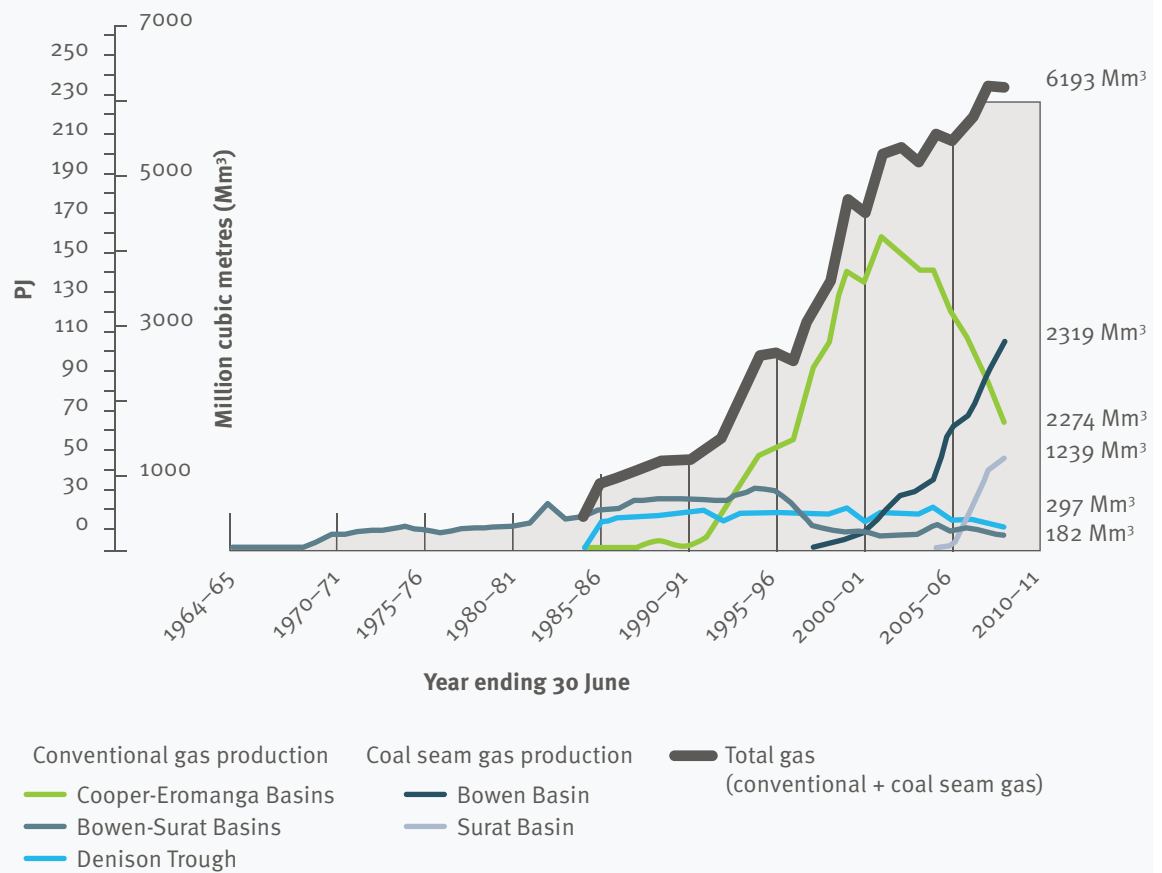


Figure 2 Conventional and coal seam gas production, 1964–2011

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	<ul style="list-style-type: none"> Queensland Gas Company (wholly owned by BG Group) Tokyo Gas China National Offshore Corporation 	<ul style="list-style-type: none"> 93.75% 1.25% 5% 	<ul style="list-style-type: none"> 87.5% 2.5% 10% 	CN00C (3.6) Tokyo Gas (1.2) Singapore (up to 3) Chile (1.7) Chubu Electric (0.4)	4 Jul 2008	23 Jun 10	22 Oct 10	31 Oct 10	2014 2015 3rd later
Gladstone LNG (GLNG)	3 x 3.6	18 Jul 07	<ul style="list-style-type: none"> Santos Petronas Total KOGAS 	<ul style="list-style-type: none"> 30% 27.5% 27.5% 15% 	<ul style="list-style-type: none"> 30% 27.5% 27.5% 15% 	Petronas (3.5) KOGAS (3.5)	16 Jul 2007	28 May 10	22 Oct 10	13 Jan 11	2015 2016 3rd later
Australia Pacific LNG (APLNG)	4 x 4.5	8 Sep 08	<ul style="list-style-type: none"> Origin Energy ConocoPhillips China Petroleum Corporation 	<ul style="list-style-type: none"> 42.5% 42.5% 15% 	<ul style="list-style-type: none"> 42.5% 42.5% 15% 	Sinopec (4.3)	9 Apr 2009	8 Nov 10	21 Feb 11	28 Jul 11	2015 2016 3rd and 4th later
Arrow LNG Project (Arrow LNG)	4 x 4	16 Feb 09 ¹	<ul style="list-style-type: none"> Shell PetroChina 	<ul style="list-style-type: none"> 50% 50% 	<ul style="list-style-type: none"> 50% 50% 	PetroChina (n/a)	12 Jun 2009	Pending IES	Pending IES	late 2013 (target)	2017? 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 Oil = \$US140/bbl Gas = \$A7–9/GJ \$US/\$A = 1.00	Moderate oil & gas Oil = \$US100/bbl Gas = \$A5–7/GJ \$US/\$A = 0.80	Low oil & gas Oil = \$US60/bbl Gas = \$A4–5/GJ \$US/\$A = 0.60
Electricity market assumptions	As per 2010 GS00*	As per 2010 GS00*	As per 2010 GS00*

* 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:

$$\text{LNG price} = 0.15 * \text{JCC price}$$

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.