Report to

DEEDI

Annual Gas Market Review

23 June 2010

MMA McLennan Magasanik Associates

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Project Team

Richard Lewis

Michael Goldman

Albert Suyanto

Paul Nidras

Lionel Chin

Mitul Patel

Melbourne Office
PO Box 825
South Melbourne Vic 3205

242 Ferrars Street
South Melbourne Vic 3205

Tel: +61 3 9699 3977
Fax: +61 3 9690 9881

Brisbane Office
GPO Box 2421
Brisbane Qld 4001

Level 2, 200 Mary Street
Brisbane Qld 4000

Tel: +61 7 3100 8064
Fax: +61 7 3100 8067

Canberra Office
GPO Box 443
Canberra City ACT 2601

Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

ACN: 004 765 235
ABN: 33 579 847 254

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EXECUTIVE SUMMARY

Introduction

The Department of Employment, Economic Development and Innovation (DEEDI) has engaged McLennan Magasanik Associates (MMA) to undertake an Annual Gas Market Review. The Annual Gas Market Review is an initiative of the Queensland Government and will inform Government decision making in relation to the need for development of a Prospective Gas Production Land Reserve (PGPLR), more effective resource management, and the development of a more competitive Queensland gas market.

As part of the review, the DEEDI has been tasked with immediately initiating an analysis of reserves, production, transport constraints and demand requirements. The primary objective of the Annual Gas Market Review is to identify and analyse key issues affecting the effective management of gas resources and reserves to support the further growth of a competitive Queensland gas market.

The Annual Gas Market Review will form part of a coordinated Whole-of-Government approach to providing regular advice to Government on constraints on gas supply availability, gas market development and security of supply. The initial review for 2010 will involve modelling of gas market supply, demand and price variations for prescribed scenarios and additional sensitivity analysis on certain variables.

Background

The Eastern Australian gas market has grown steadily since the late 1960s, supported by conventional gas reserves that have remained relatively static since approximately 1980 (Figure E1). The past decade however has witnessed rapid growth of coal seam gas reserves, mainly in Queensland, to the extent that by 2008 it was clear that they could rapidly exceed domestic requirements if a market could be found, otherwise they may not be developed (Figure E2).

The preferred route to excess gas monetisation is LNG, a global market that saw rapid growth and high prices during the oil price surge from 2003 to 2008. In due course eight proposals were put forward to export LNG from liquefaction plants to be built on the Queensland coast, seven at Gladstone and one at Abbot Point. The proposals have made varying degrees of progress and a number are now almost at the point of a final investment decision.

While there is every reason to believe that the CSG reserves to support some if not all of the LNG projects will eventually be proved up, none of the proponents currently has sufficient proved reserves for the likely duration of their project. In the short-term this has led to husbanding of reserves by producers, with a relative lack of reserves available to support new domestic gas contracts.

Figure E 1 Aggregate conventional gas resources and reserves, Eastern Australia

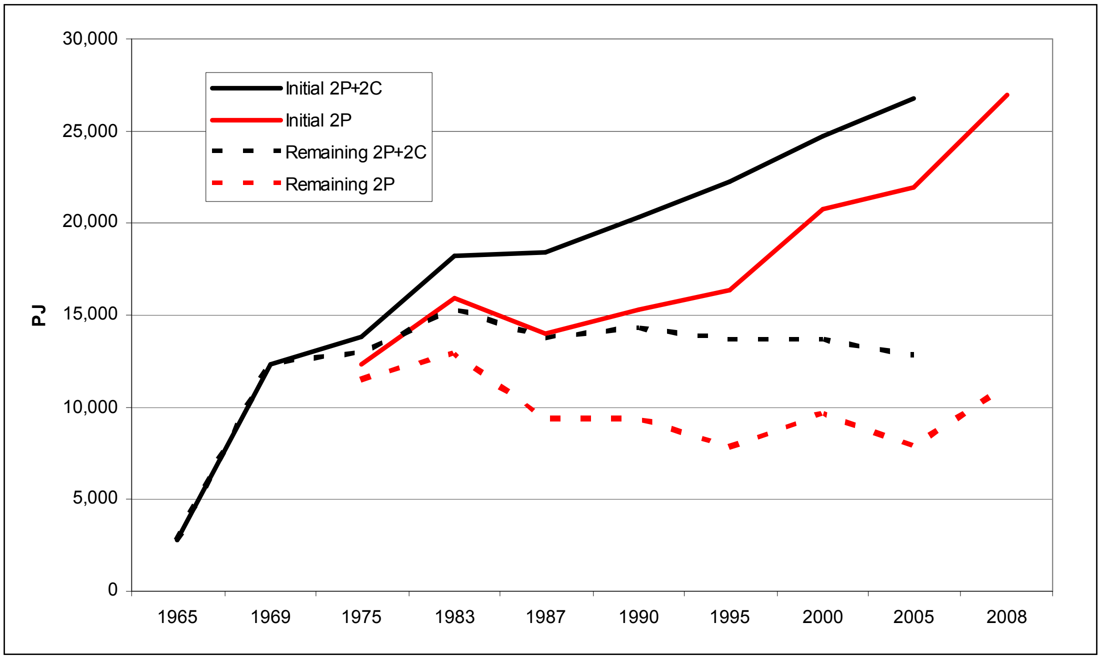
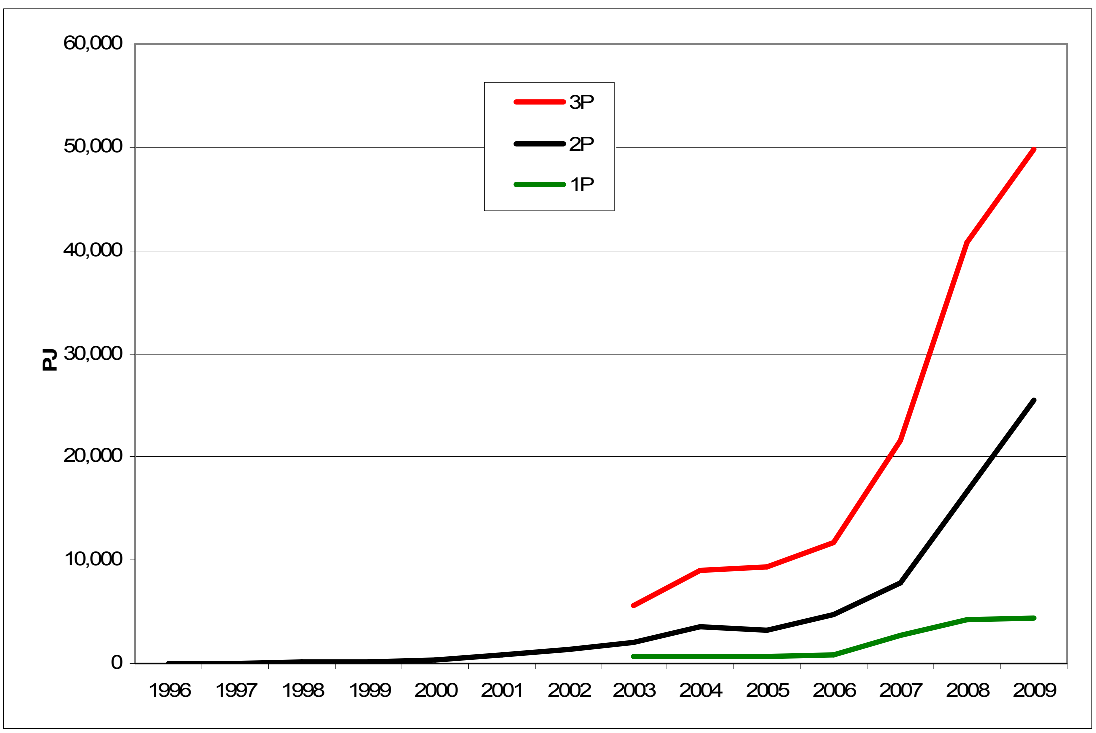


Figure E 2 Aggregate CSG reserves, Eastern Australia



The Queensland Government has considered and rejected the concept of reserving a percentage of gas produced as a means of ensuring availability of gas for new domestic contracts. Instead the Government has adopted the approach that it will, if necessary, set aside prospective acreage to be dedicated to the domestic market.

The Annual Gas Market Review is an initiative to inform Government decision making in relation to the need for development of a Prospective Gas Production Land Reserve (PGPLR), more effective resource management, and the development of a more competitive Queensland gas market.

Findings

In order to assess the future balance of gas demand and supply across Eastern Australia MMA has:

- developed three scenarios of future gas demand for the domestic sector and for export as LNG
- reviewed gas reserves and determined potential reserves development profiles
- reviewed gas production and transmission cost assumptions
- conducted assessments of the demand-supply balance and price outcomes in the three scenarios and the impact of prices on demand
- examined the capacity expansion requirements for pipelines (in Queensland only)

Figures E3 and E4 below illustrate the projected domestic and export reserves requirements respectively and demonstrate the potential for export requirements to considerably exceed those of the domestic market.

Figure E5 shows projected aggregate 2P reserves, with growth at the maximum level that appears possible. Comparing the aggregate demand and supply requirements in Figure E6 it would be easy to conclude that there will not be any gas reserve adequacy issues in the short to medium term, since there are buffers of at least 20,000 PJ of uncontracted reserves in all scenarios. However the aggregate projections conceal the current commercial reality that there are four competing major LNG projects, each aiming to meet its own reserves requirements for its planned FID, regardless of the eventual actual timing of their projects. Consequently the volumes of gas available for the domestic market are likely to be considerably less than the buffers illustrated.

To obtain a more representative picture than the aggregate one above we have developed detailed demand-supply balances, including price outcomes, for each of the High, Medium and Low scenarios.

Figure E 3 Projected incremental reserves requirements for the domestic market

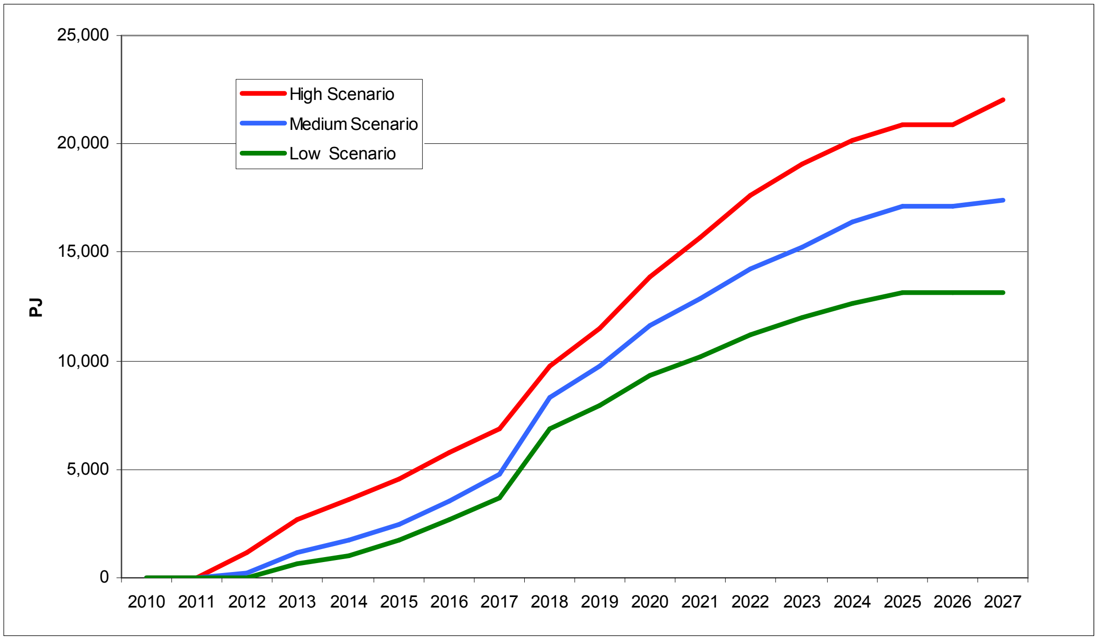


Figure E 4 Timing of gas reserve commitments for LNG exports

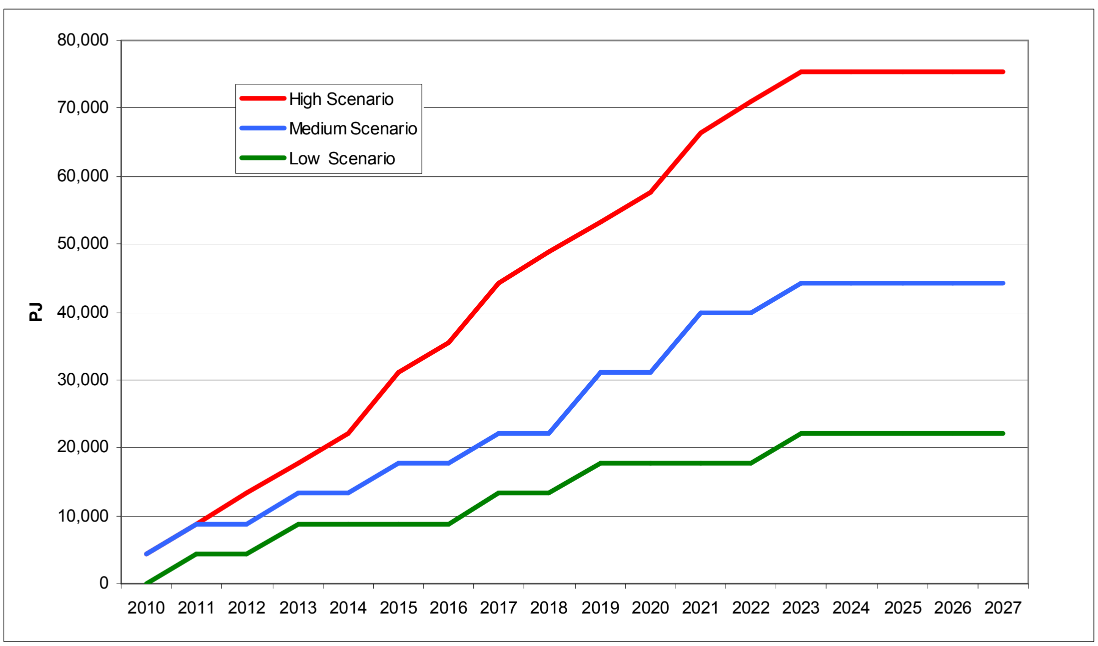


Figure E 5 Projected aggregate uncontracted gross 2P reserves with maximum growth assumptions

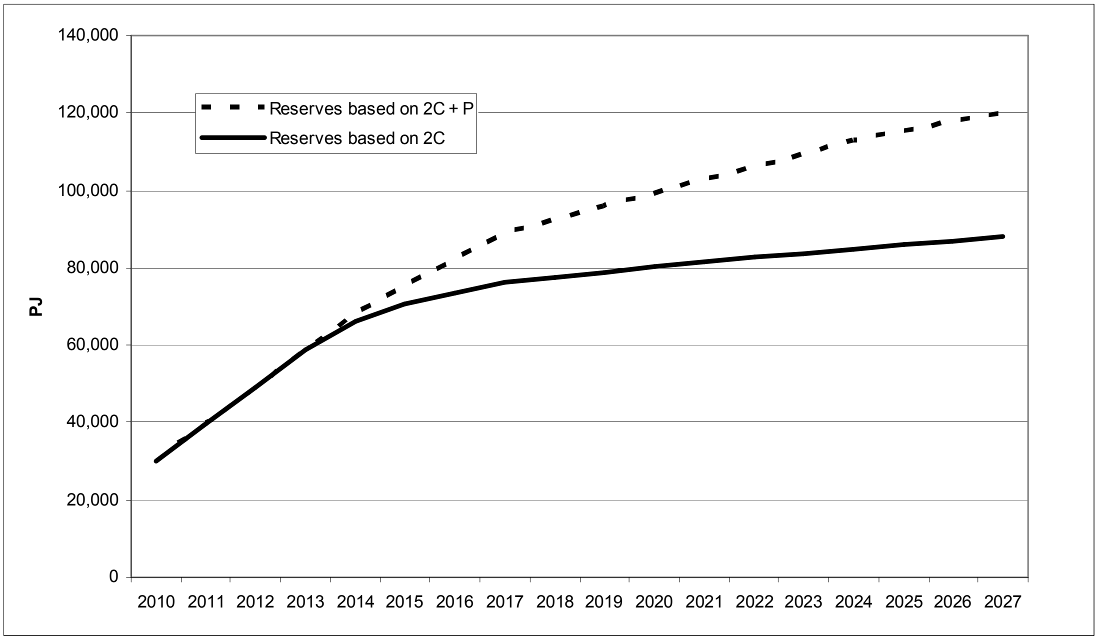
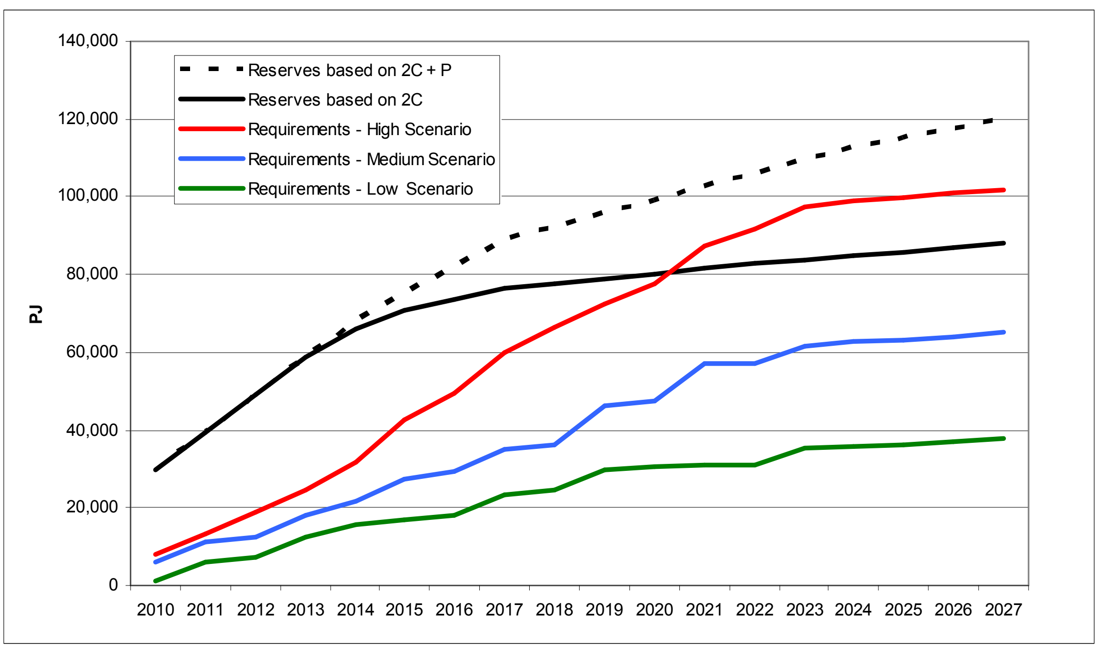


Figure E 6 Combined domestic + LNG reserve requirements vs 2P uncontracted gross reserve projections (PJ)



Eastern Australian gas supply is projected to come increasingly from CSG, not only from Queensland but also New South Wales (Figures E7 and E8).

Figure E 7 Projected gas supply, Eastern Australia domestic only, Medium Scenario

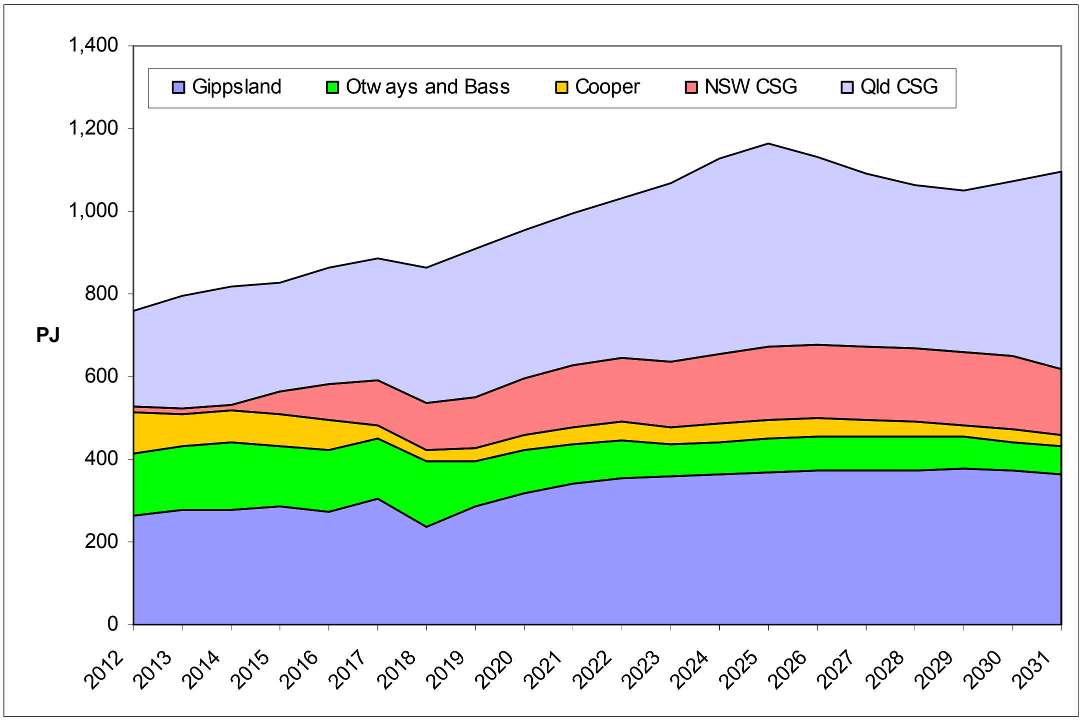
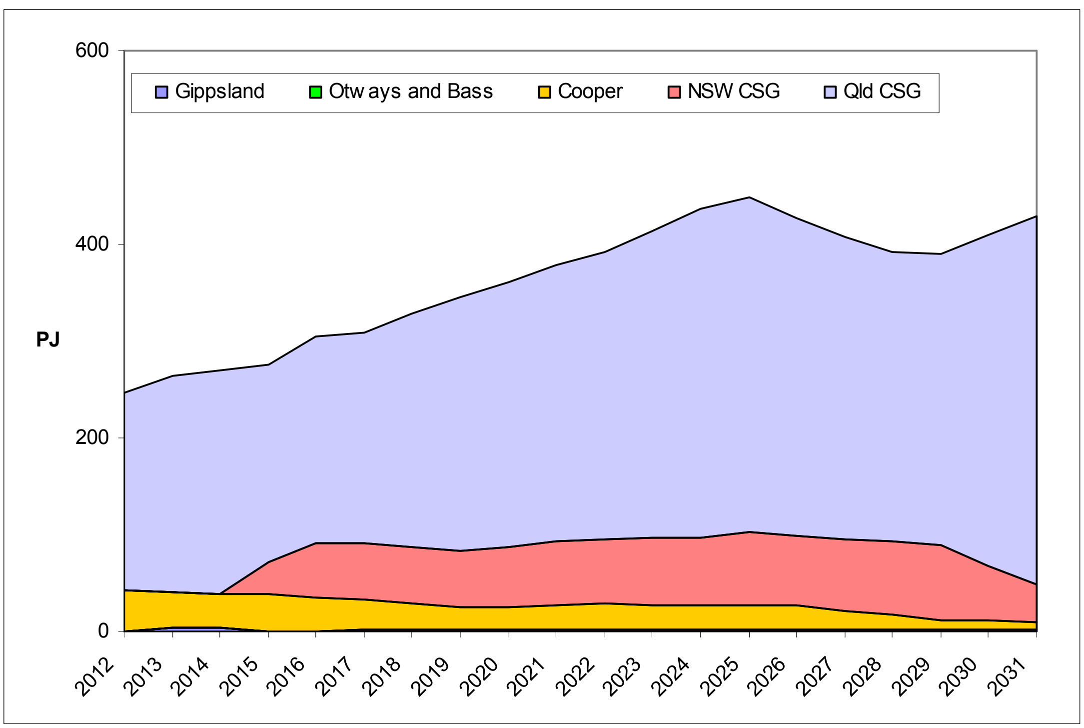


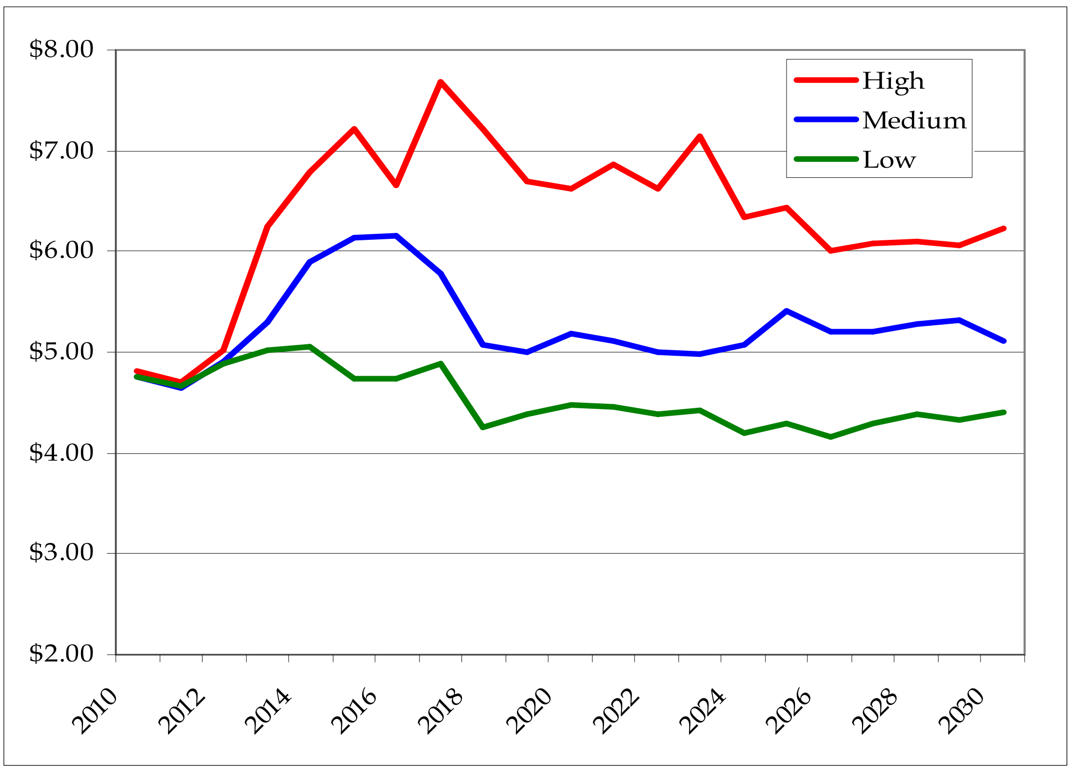
Figure E 8 Projected gas supply, Queensland domestic only, Medium Scenario



The domestic supply patterns vary considerably between scenarios, with less Queensland CSG in the High scenario, where it is more dedicated to export, and more NSW CSG and Cooper Basin gas.

Projected delivered gas prices in Queensland also vary considerably between scenarios (Figure E9). New contract prices are projected to remain relatively flat in the Low scenario, to rise by over $1/GJ and then fall back in the Medium scenario and to rise by more than $2/GJ in the High scenario and then decline slowly. Similar patterns apply in all Queensland zones apart from Mt Isa. Average contract prices follow new contract prices with a considerable time-lag.

Figure E 9 New contract prices Queensland aggregate, all scenarios ($/GJ, $2010 real)



Projected prices in the southern states are markedly different owing to the availability of NSW CSG (Figure E10).

Figure E 10 New contract prices Southern States aggregate, all scenarios ($/GJ, $2010 real)

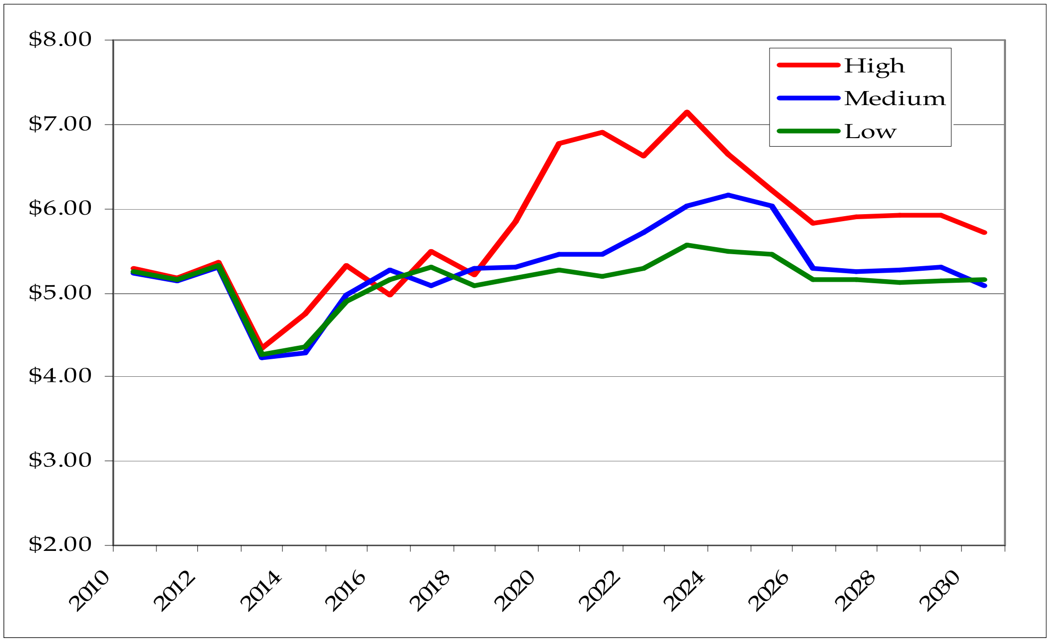


Figure E 11 Average contract prices Southern States aggregate, all scenarios ($/GJ, $2010 real)

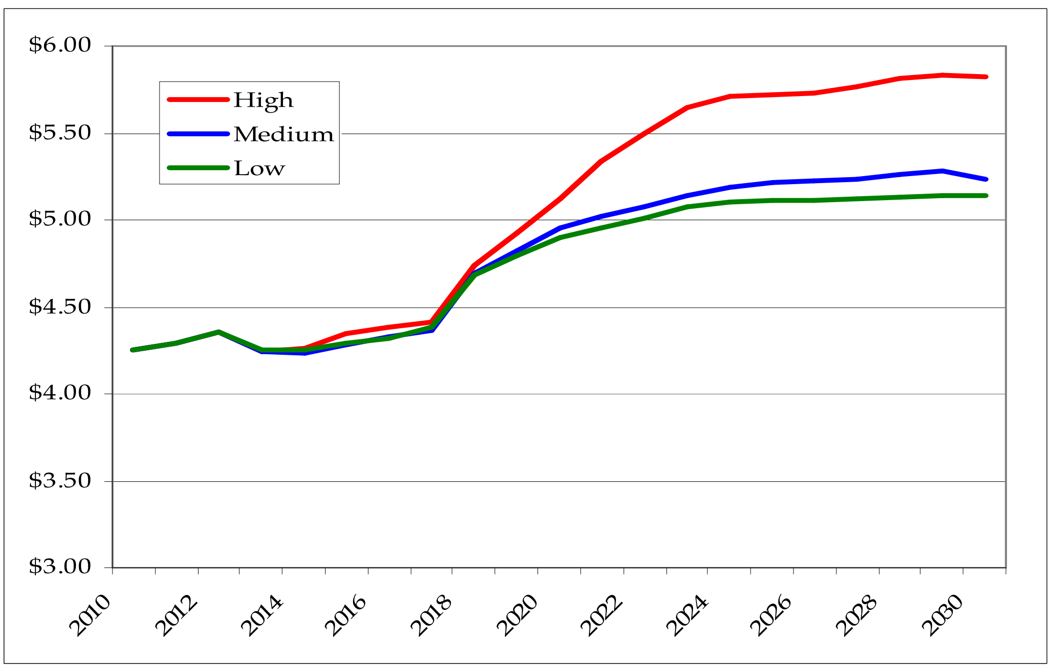
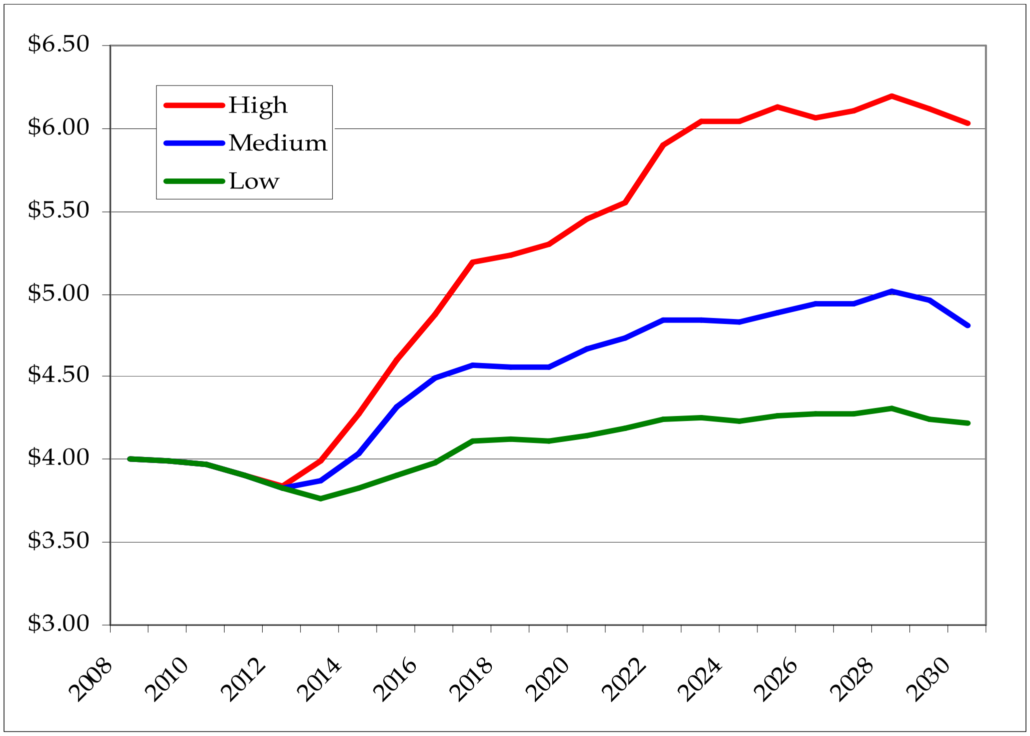


Figure E 12 Average contract prices Queensland aggregate, all scenarios ($/GJ, $2010 real)



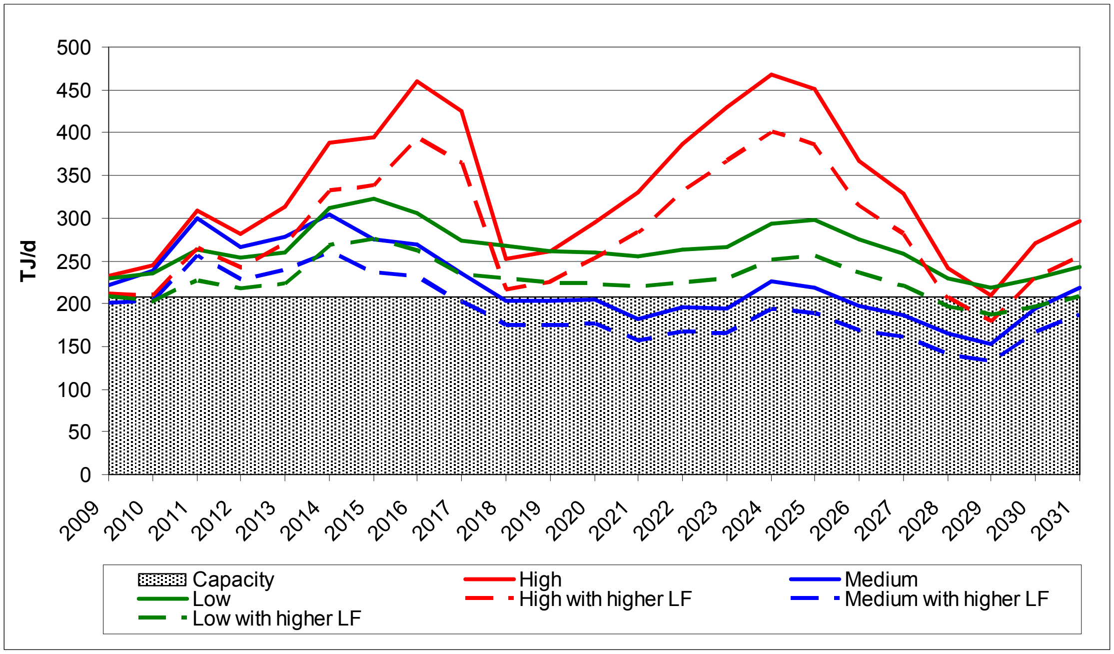
The projected increases in average prices in all scenarios give rise to reductions in demand by 2030, relative to projections based on current prices, ranging up to 28% in Queensland in the High Scenario (Table E 1).

Table E 1 Estimated demand reductions by 2030 due to price increases

	Low scenario	Medium scenario	High scenario
Eastern Australia	5%	8%	17%
Queensland	6%	13%	28%

Pipeline capacity appears adequate in the short to medium term for all major pipelines except the Roma to Brisbane pipeline, which appears to be at full capacity already.

Figure E 13 Estimated peak flow and capacity - Roma to Brisbane Pipeline (RBP)



1 INTRODUCTION

1.1 The Annual Gas Market Review

The Annual Gas Market Review is an initiative of the Queensland Government and will inform Government decision making in relation to the need for development of a Prospective Gas Production Land Reserve (PGPLR), more effective resource management, and the development of a more competitive Queensland gas market.

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The Annual Gas Market Review will form part of a coordinated Whole-of-Government approach to providing regular advice to Government on constraints on gas supply availability, gas market development and security of supply. The initial review for 2010 will involve modelling of gas market supply, demand and price variations for prescribed scenarios and additional sensitivity analysis on certain variables.

1.2 This study

Through a competitive tender process DEEDI has appointed MMA to develop a robust gas market model, to analyse the economic and regulatory constraints and drivers affecting prices, and to analyse the likely impact of these constraints and drivers on future gas prices and investment in the gas market.

MMA's approach to providing these services is based around MMA's existing gas supply-demand model, MMAGas (Market Model Australia – Gas). MMA first developed this model of the Eastern Australian[1] gas market in 2003 and has subsequently adapted it to the changing circumstances in the market. Recent model development has focussed on modelling the rapid growth of CSG reserves, particularly in Queensland, and their availability for domestic supply. Descriptions of MMAGas are presented in section 6.2 and Appendix A.

Key issues that have been modelled using MMAGas include:

- The impact of imports from PNG on domestic pricing and production
- Price impacts of increased gas use for power generation
- Impact of CSG-LNG projects on domestic pricing and demand

[1] A separate Western Australian version has also been developed

For the purposes of this study MMA has reviewed and updated relevant features of and inputs to MMAGas including:

- Interaction of domestic and export markets (section 6.2)
- Domestic gas demand (sections 4.1 to 4.3)
- LNG export project proposals (section 4.5)
- Gas reserves and resources and their modelling (sections 5.1 to 5.4)
- Gas contract commitments (section 5.5)
- Gas production costs (section 5.6)
- Potential pipeline construction (section 5.7)

The demand-supply balances have been assessed under three scenarios labelled low, medium and high, which are broadly consistent with the scenarios adopted by AEMO for the GSOO 2009.

Two features distinguish the approach used in this study from the approaches used in other studies (some recent studies are listed in the text box on the following page):

1. A focus on dynamics and the timing of resource development relative to demand. Our approach views the gas market as a market for long-term contracts negotiated in advance of actual supply. Supply competition in this market is between suppliers who have 2P reserves (defined in section 5.1) available to commit to contracts at the time of negotiation.

2. Projection of price outcomes derived from the demand-supply balance. Price depends on supply costs, levels of competition and customers' willingness to pay and reflects the tightness of supply. Although there is no imbalance as such in economic models such as MMAGas, the demand that is met by supply is typically not the demand that is specified as input but demand that is adjusted through the pricing mechanism. MMAGas therefore does offer a measure of "imbalance", namely the difference between the input and output demand levels.

Other Recent Gas Demand-Supply Studies[2]

A number of other recent studies have addressed gas demand and supply in Australia and/or Eastern Australia:

1) "State of the Energy Market 2009" published by AER in 2009

2) "Gas Statement of Opportunities" (GSOO) published by AEMO in 2009

3) "Australian Energy Resource Assessment" (AERA), published by DERT, Geoscience Australia and ABARE in March 2010

4) "Gas Market Report" prepared by KPMG for APPEA and released in May 2010

These studies all conclude that there are sufficient gas resources to meet anticipated levels of demand, including exports, over the next 20 years. The AER study discusses the price impact of higher supply costs and gas exports but does not present any price projections or estimates of price impacts. The AEMO GSOO report considers details of demand and supply including timing of reserves development and production/pipeline capacity requirements, but also does not present any price projections or estimates of price impacts. The AERA and the Gas Market Report do not address details of demand supply balances.

1.3 Notes regarding relevant Commonwealth Government policies

MMA wishes to draw readers' attention to recent Commonwealth Government announcements of changes to proposed legislation that may impact the gas market outcomes projected in this study.

1.3.1 RSPT

The Commonwealth Government announced on 2nd May 2010 that it proposed to introduce a new tax on resource based industries. The Resources Super Profit Tax (RSPT) would levy a 40% tax on non-renewable resource company profits in excess of a benchmark rate of return. Resource royalties will continue to be paid and payments will be netted off RSPT payments.

The timeframe for this study has not permitted an assessment of the impact of the RSPT on the gas sector to be undertaken. The potential impacts of the RSPT include:

1. Higher target gas prices to achieve the same after tax profit
2. Reduction in gas reserves because of a decline in commerciality
3. Deferral or abandonment of some projects, including Gladstone LNG projects

[2] All of these studies can be downloaded from the publishers' websites

4. Potentially higher gas prices and lower domestic demand but this depends critically on the balance between 1, 2 & 3 above. If LNG projects are deferred, domestic prices could be lower.

1.3.2 CPRS

The Commonwealth Government announced on 28th April 2010 that the planned start of the Carbon Pollution Reduction Scheme (CPRS) scheme had been deferred until 1 July 2013. MMA is in the process of determining potential carbon price paths starting from this date – prior to this announcement MMA had been basing analyses impacted by CPRS on a 1 July 2012 date and this date has been used in this study. MMA believes that the impacts on gas fired generation of changing from 2012 to 2013 start dates will be relatively minor compared to uncertainties regarding the 2020 carbon reduction targets and the carbon price path, which uncertainties will remain after the date of introduction is confirmed.

2 ENERGY-ECONOMIC SCENARIOS

2.1 Intention of the scenarios

The scenarios MMA has developed are intended to provide three alternative views of how economic outcomes and policy settings relevant to natural gas and energy usage could develop over the next 20 years. They are framed in order to allow significantly different, but not unrealistic, inputs to be used while remaining reasonably internally consistent.

The three cases developed are referred to as the Low, Medium and High economic growth scenarios, though the economic parameters are not the only parameters that change from scenario to scenario. It is noted that the scenarios correspond to low, medium and high gas demand scenarios for both the domestic and export sectors, though that is not their direct purpose.

The scenarios have been intended to be used as the framework for:

- thinking about large-scale feedstock and mineral processing developments
- inputs for MMA's electricity and gas for power generation forecasts
- MMA assumptions about LNG developments.

2.2 Key scenario variables

The key scenario variables for the purpose of the Demand Scenarios forecast are:

- Economic parameters including timing of recovery from the global financial crisis (GFC), economic growth, associated commodity prices
- Carbon Pollution Reduction Scheme (CPRS) parameters, specifically the price of carbon
- LNG development in Queensland
- Oil and gas prices consistent with each set of the above
- Electricity market assumptions: demand, policy settings and gas input prices.

While we have tried to balance internal consistency among a range of inputs this has not always been possible. For example, in our high scenario we have assumed high commodity prices together with high CPRS prices. This is not necessarily consistent with a shift from high emissions intensive commodities expected with high carbon prices. It is, nonetheless, a feasible outcome. Under high economic growth there could be a tight supply/demand balance for most commodities with Australian producers remaining competitive.

2.3 Key Scenario Components

2.3.1 Global financial crisis and economic conditions

A major source of uncertainty in recent years has been the length of time that the GFC was expected to continue and the speed at which confidence returns to global markets. This appears to have resolved somewhat, at least for Australia, over the past year.

The Medium economic growth scenario assumes that the global financial crisis has been largely resolved by mid 2010. This is associated with a moderate global economic recovery, somewhat stronger in Asia and Australia, and the move towards higher global commodity prices seen over the past year.

The High economic growth scenario assumes that the global economy is stronger than in the Medium economic growth scenario and commodity prices are higher.

The Low economic growth scenario assumes that world economic recovery is fitful, with relatively low growth and commodity prices lower than in the medium scenario.

2.3.2 Carbon Pollution Reduction Scheme (CPRS)

Note: please refer to section 1.3.2 regarding the deferral of introduction of the CPRS to 1st July 2013 at the earliest.

The past year has seen significant changes in expectations about greenhouse gas measures and even the prospects for a CPRS in Australia. There now appears to be a wider range of potential outcomes than appeared likely a year ago.

We currently consider the following three scenarios to provide a reasonable range of plausible and possible outcomes:

- Medium economic growth scenario. A CPRS scheme or similar commencing a year later than recently envisaged (i.e. now 2012/13) and still with a fixed $10/t CO2 price in the first year. A CPRS–5% target by 2020.
- High economic growth scenario. A CPRS scheme or similar commencing a year later than recently envisaged (i.e. now 2012/13) and still with a fixed $10/t CO2 price in the first year. A CPRS–25% target by 2020 is eventually agreed following strong international agreement; however, it takes five years to move from the CPRS-5% target.
- Low economic growth scenario. No CPRS scheme, but, in the without-CPRS world, it has been assumed that other "direct" measures would be adopted, namely: energy efficiency program to reduce electricity demand by 10% by 2020; no new conventional coal plant, and a modest carbon price; gradual phase out of old coal plant (funded from revenues from carbon price); investment in demonstration low emission technologies; and NGGAS continues until 2020.

2.3.3 LNG developments

We have made the following Queensland LNG project assumptions for our scenarios:

- High economic growth scenario: 3.5 Mtpa in 2014 plus an additional 3.5 Mtpa every year.
- Medium economic growth scenario: 3.5 Mtpa in 2014 and 2015 followed by an additional 3.5 Mtpa every two years.
- Low economic growth scenario: 3.5 Mtpa in 2015 and 2017 followed by an additional 3.5 Mtpa every three years on average.

The above are all projects based on CSG in Queensland with Gladstone hosting the LNG plants and export terminals. Details are discussed in section 4.5.

2.3.4 Oil and gas prices

Delivered LNG prices are expected to be strongly related to oil prices. For the purposes of this study we have selected oil price scenarios as follows:

- Low economic growth scenario: Slightly below current prices at $US65/bbl.
- Medium economic growth scenario: Approximately at current prices of $US80/bbl.
- High economic growth scenario. Above current prices at $US100/bbl.

Current expectations of domestic gas prices for new contracts based on other recent studies are provided below. These are inputs to demand projections and are not the same as the outputs from our supply-demand modelling.

We have started off with our expectations under a Low economic growth scenario, associated with relatively low commodity prices and relatively slow LNG development, of gas prices for new contracts being about $3.50 to $4.50/GJ ex-plant in $2010 terms, i.e. a similar range to today's prices. We have then assumed the following ex-plant gas prices as being approximately consistent with the other scenarios:

- Low economic growth scenario: Approximately current prices for new gas contracts of $3.50-$4.50/GJ ex-plant in $2010.
- Medium economic growth scenario: We expect gas prices for new contracts to be between $4 and $6/GJ (in $2010), but with lower prices within this range in later years as reserves are developed.
- High economic growth scenario. Given the high oil price, LNG and carbon price developments the gas price is expected to be some $2/GJ higher than that in the Medium economic growth scenario. We assume a price of new gas contracts of $6/GJ to $8/GJ ex-plant in $2010.

2.4 Electricity modelling considerations

MMA's electricity modelling requires a great number of inputs. We discuss only a few key variables below. In many cases, for example heat rates, the input assumptions will be the standard ones contained within the MMA data bases.

2.4.1 Electricity demand

We have used the medium, high and low ESOO 2009 electricity demand forecasts. These are adjusted to take into account different carbon price profiles and the impact of direct measures.

2.4.2 LRET and SRES

We have for all scenarios assumed the current policy settings for LRET and SRES.

2.4.3 Carbon capture and storage (CCS)

The assumptions about the timing of CCS commercialisation play a significant role in electricity and gas expectations and outcomes. In the Medium and Low economic growth scenarios we have assumed that the first commercial CCS coal plant in Australia is commissioned by 2026. In the High economic growth scenario we assume this is moved forward to 2024.

2.4.4 Gas prices

We have assumed the gas prices for new contracts discussed in Section 2.3.4 and blended these with our understanding of existing gas prices, by location and generation duty (i.e. base, intermediate and peak).

2.5 Summary of scenarios

The key components of the MMA Low, Medium and High economic growth scenarios (GS) are summarised in Table 2-1.

Table 2-1 Overview of scenario assumptions

Scenario	Low economic GS	Medium economic GS	High economic GS
Economy	World growth is relatively slow .and patchy. Commodity prices remain relatively subdued. Australian economic growth is moderate.	Moderate global recovery over the next 5 years, with rebound and above-average growth in Australia over the next two to three years and then stable growth thereafter.	More rapid and sustained global recovery from GFC and associated stronger commodity prices and growth in Australian projects.
CPRS and Carbon Price	No CPRS scheme as such but then "direct measures" including a reduction of electricity demand by 10% by 2020 and a weaker carbon price than in the Medium scenario.	CPRS-5 target throughout starting July 2012. Carbon prices set at $10/t in 2012/13.	CPRS-5 (as in Medium) for first 5 years. Then a strong global agreement on carbon reduction is arrived at with a CPRS-25 target from 1 July 2017. This results in a significant increase in carbon price.
LNG	First 3.5 Mtpa train in 2015 increasing by 3.5 Mtpa each 3 years.	First two 3.5 Mtpa trains in 2014 and 2015, then increasing by 3.5 Mtpa each 2 years.	First 3.5 Mtpa train in 2014 increasing by 3.5 Mtpa each year.
Oil prices	$US65/bbl	$US80/bbl	$US100/bbl
Indicative New contract gas Prices ex-plant	$3.50 to $4.50/GJ	Between $4 and $6 over the period, but with lower prices later	$6 to $8/GJ
Electricity inputs	Low ESOO electricity demand scenario. No CCS.	Medium ESOO electricity demand scenario. CCS in 2026.	High ESOO electricity demand scenario. CCS in 2024.

3 GAS MARKET DEVELOPMENT

3.1 Historical development

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has a growing domestic market, estimated at 645 PJ in 2009, supported by substantial conventional and coal seam gas (CSG) reserves – 2P reserves at 31/12/2009 are estimated at 36,208 PJ. Regional breakdowns of these figures are shown in Table 3-1.

Table 3-1 Gas demand and reserves by state, 2009 (PJ)

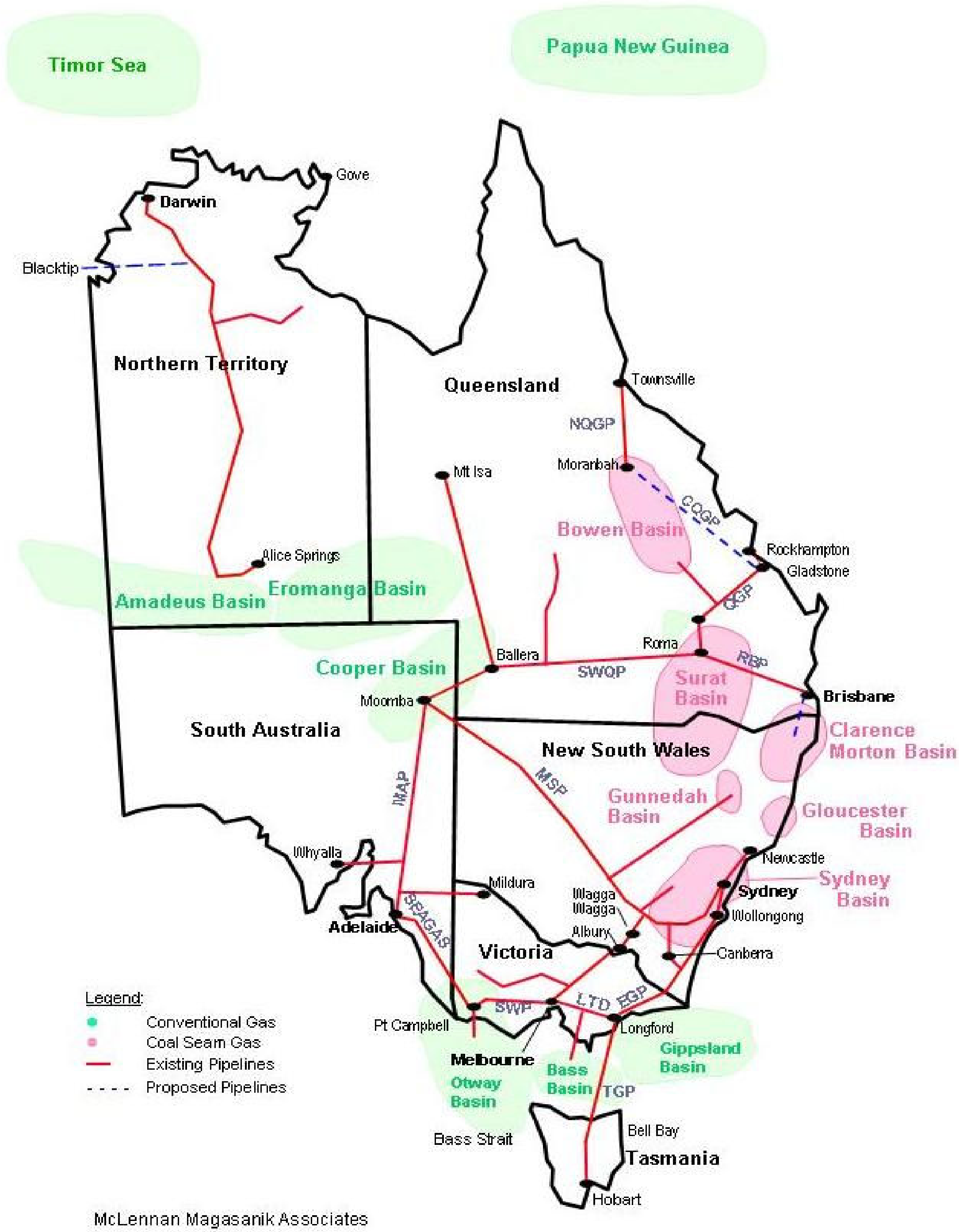
	NSW	Victoria	SA	Tasmania	Queensland	Total
Demand	140	227	105	8	164	645
Reserves	2,466	9,035	1,195	487	23,025	36,208

Demand and supply patterns in this market have operated in isolation from other gas markets in Australia and overseas because to date there have been no gas exports from or imports to the region. Recent growth of CSG reserves, to levels in excess of foreseeable domestic demand, has led to a number of proposals to monetise reserves by exporting LNG to markets in Asia and elsewhere. These export projects have the potential to considerably change the domestic market, both in terms of the demand-supply dynamics and the nature of the participants.

The prospect of exports emerged relatively suddenly and unexpectedly, following a long history of perceived excess of demand over local supply and a corresponding history of proposals to import gas from the North West Shelf in Western Australia, from Papua New Guinea and from the Timor Sea. All of these proposals have been deferred because of unforeseen growth in Eastern Australian gas reserves and supply, most recently the CSG reserves in Queensland.

The majority of Eastern States sub-markets are now served by multiple basins and/or pipelines, the key exception being Townsville (Figure 3-1). Planning for a pipeline between Moranbah and Gladstone, which would link Townsville to other supplies, is well advanced but construction appears to be contingent upon LNG development in Gladstone using gas from the Moranbah area. The QSN Link between Ballera and Moomba, which commenced operations in February 2009, directly links Queensland supply to the southern states, replacing the previous swap arrangements.

Figure 3-1 Gas basins and pipeline infrastructure, Eastern Australia



The dominant transactions in the Eastern Australian gas market are long-term gas sales agreements (GSAs) between gas producers and buyers such as retailers, large industrial users and generators. There is a gas pool in Victoria operated by the Australian Energy Market Operator (AEMO) for the primary purpose of balancing the transmission/distribution system – the pool price is used to settle injection/withdrawal imbalances. Bidding into the pool is compulsory for all transmission/distribution system users, most of whom are retailers buying gas from producers under GSAs. The purposes of the short-term trading markets (STTMs) being established in Adelaide, Brisbane and Sydney by AEMO are similar and they will also share many features with the Victorian approach. In general the pool prices are determined by the prices set in the GSAs rather than vice versa, though at least one proposed GSA has included a price linked to the Victorian pool price. The Victorian pool price does provide some price transparency in the face of the confidential nature of GSA prices.

The level of gas producer competition has until now been sufficient to maintain price levels for new GSAs in the south-east and to reduce prices in some Queensland sub-markets. It is widely believed that gas exports will lead to higher domestic prices but price rises are likely to be constrained by domestic users' willingness to pay.

3.2 Factors influencing future directions

The primary factors influencing the future direction of the gas industry in Eastern Australia are perceived to be the CPRS (or carbon pricing generally) and the potential export of LNG.

3.2.1 Carbon pricing

In the electricity sector carbon pricing has the effect of making gas more competitive with high carbon coal, which currently dominates base load generation in Eastern Australia, but simultaneously less competitive with low or no carbon options such as renewables. Whether carbon pricing leads to an increase in gas use or not is therefore determined by the balance of pressures from either side. These pressures have also been adjusted, both in favour of and against gas, for example by the Queensland GECS scheme and by the RET. On balance however in most markets and scenarios it appears that carbon pricing favours gas in the period to 2025-30, after which new technologies such as "clean" coal are expected to depress gas use 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 liquids back-up.

Carbon pricing will also increase the end-use cost of gas for other usage, potentially reducing usage in non-generation sectors. However here too 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 being paid by end-users or retailers.

3.2.2 LNG exports

The potential impacts of LNG exports from Eastern Australia are outlined below.

3.2.2.1 Gas scarcity

The LNG projects will use substantial volumes of gas, approximately 220 PJ/yr per 3.5Mtpa train, so four trains would equal the Eastern Australian domestic market. There has been widespread concern among domestic gas buyers that this will cause a general gas scarcity and substantially higher prices, fears which have been reinforced by many gas producers' unwillingness to enter new contract discussions with domestic buyers until the LNG developments are firmed up.

Our assessment of the demand-supply and price outlooks under various scenarios is reported in section 6.

3.2.2.2 Link to higher value market

Linked to the above concern is the widely stated expectation that when exports commence domestic pricing will inevitably move to export price parity, as measured by the netback value of LNG. While this is a potential outcome, it is clearly not going to occur if exports are well below potential. MMA takes the view that the outcome will depend on whether export capacity grows faster than gas reserves.

3.2.2.3 Qualitative market changes

The LNG projects have resulted in consolidation of many CSG producers, though there is still more upstream competition than in the pre-CSG era. All the major projects now also involve overseas players, with one project, QCLNG, under 100% foreign control (by BG Group) and another, the Arrow-LNGL project, under takeover offer (by Shell/PetroChina).

These changes will certainly result in different decision processes regarding investment in CSG production compared to the formerly small CSG producers and may also result in different outcomes due to the different priorities of the new owners.

3.2.2.4 Gas trading

Balancing gas supplies to a group of large LNG plants will most likely result in an increase of trading among LNG participants and other gas traders. The ability to trade could be reinforced by availability of gas storage at the confluence of major pipelines, for example at Wallumbilla, creating a genuine gas hub similar to the Henry Hub in Louisiana, the primary spot and futures price setting hub in the US.

4 GAS DEMAND

4.1 Key drivers over the next twenty years

The key drivers of gas demand over the coming 20 years, apart from gas usage in power generation, are expected to include:

- in the short and medium-term, the remaining impact on the global and Australian economies of the Global Financial Crisis (GFC). In the longer term, economic growth generally.
- the impact of measures undertaken to reduce Australian greenhouse gas emissions, in particular, whether the Carbon Pollution Reduction Scheme (CPRS) is adopted, if so, the target set and its impact on large scale industrial operations and projects and driving energy efficiency in the residential and small commercial sectors. If the CPRS is not adopted, what measures will be adopted and their expected impacts.
- commodity prices, which feed into large gas-intensive projects including liquefied natural gas (LNG).
- east coast LNG projects based on coal seam gas (CSG) impacting on gas price.
- Government climate change and energy efficiency programs.
- Structural shift to less energy intensive economic growth, including a growth in services at the expense of manufacturing and a loss of Australian competitiveness in some areas of manufacturing.
- demographics
- other changes to average usage per small customer.

These are discussed in some detail below. Following this, the three demand scenarios used by MMA for assessing demand are described.

4.1.1 Global financial crisis

While the effects of the GFC have been relatively mild in Australia and parts of Asia, the impact on much of the rest of the world has been significantly harsher. In Australia, the key impacts were a short-term reduction in economic growth and a deferral by one to three years of many major gas consuming projects.

MMA has assumed in the medium economic growth scenario that the GFC has been largely resolved by mid 2010 and that there will be a period of somewhat stronger growth for two or three years followed by moderate economic growth thereafter. The Medium economic growth scenario assumes that by mid 2010 financial markets have stabilised and global and consumer confidence largely restored. This is associated with a moderate global economic recovery, somewhat stronger in Asia and Australia, and the move towards higher global commodity prices seen over the past year. This is associated with a mild rebound in expectations about new resource projects.

We assume that, over the period to 2030, economic growth will average about 2.6% across Eastern Australia as a whole and 3.2% in Queensland. This is approximately in line with recent Australian Bureau of Agricultural and Resource Economics (ABARE) expectations[3].

The high economic growth scenario assumes more rapid growth, 3.2% in Eastern Australia and 4% in Queensland, while the low economic growth scenario sees a slower recovery from the GFC, 2% in Eastern Australia and 2.7% in Queensland.

4.1.2 Greenhouse emission reduction

A year ago there was an expectation that the Federal Government's CPRS with a CPRS-5 target would shortly be introduced. However, the Federal Government initially delayed the introduction of the scheme and has subsequently not been able to secure the passage of the CPRS legislation through the upper house. The outcome of the Copenhagen summit was also seen as disappointing and the Federal Opposition appears implacably opposed to any form of emissions trading, preferring "direct action" policies.

As a result, while there is a continued expectation that greenhouse emission reductions will eventuate, the extent of the savings and the means by which they are to be achieved are uncertain. The uncertainty will not be resolved until after the federal election, scheduled to be held within the next year.

The CPRS-5 policy, with delayed and staged introduction, as outlined in the medium economic growth scenario currently appears to be the most likely outcome. However, there is a possibility that the world will eventually come to a strong agreement about the need to curb emissions and the outcomes under such a policy are explored in the High economic growth scenario. Conversely, a change of Government and continued lack of agreement among nations may lead to weak emission targets, as in the Low economic growth scenario.

4.1.3 Commodity prices

For many large energy using projects, apart from power generation, commodity prices such as metal, ammonia and crude oil prices are a major consideration. Commodity prices increased significantly over the four years to about mid to end December 2008, then dropped significantly, by 50% or more in most cases.

Since then commodity prices have increased substantially from their low points, typically of the order of 100%, making those of interest[4] currently some 70% to 75% of their maximum values.

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[3] Australian Bureau of Agricultural and Resource Economics, "Australian energy projections to 2029-30", ABARE research report 10.02, March 2010.

[4] We have considered prices of aluminium, copper, lead, zinc, nickel, cude oil and ammonia.

We have assumed that:

- In the Medium economic growth scenario these prices will remain a little higher than current values in real terms, averaging some 77% of maximum values
- In the High economic growth scenario these prices will be a little stronger, averaging some 92% of maximum values in real terms
- In the Low economic growth scenario these prices will be weaker and generally lower than current prices by about 5% to 10% and averaging some 64% of maximum values in real terms.

4.1.4 LNG developments

LNG developments in Queensland are a key consideration in assessing the domestic gas price likely to prevail over the period in question, with over 40 Mtpa under consideration. The rate of growth of the Queensland LNG industry is likely to impact on the domestic price of gas – if it is close to or exceeds rate of growth of reserve development, domestic price increases may be expected.

LNG development assumptions and scenarios are described in section 4.5.

4.1.5 Gas prices

We have assumed that, largely as a result of the LNG developments, the price of gas will increase by varying amounts in each scenario (refer to section 2.3.4).

4.1.6 Government climate change and efficiency policies

Both households and the non-residential sector are expected to become more energy efficient over time due to a combination of measures and programs, including among others:

- the CPRS scheme. This is eventually expected to increase electricity prices to households by some 18% and gas prices by some 12% in the CPRS-5 case, more in the CPRS-25 case.
- the NSW BASIX scheme which has imposed water, energy and thermal comfort efficiency requirements on new houses in Sydney since 1 July 2004 and on additions and alterations since 1 October 2006.
- national reporting of greenhouse emissions by large commercial and industrial energy users from 1 July 2008 and the implementation of the national Energy Efficiency Opportunity Act which requires that any energy efficiency opportunity with a payback period of 3 years or less be reported on.
- minimum energy performance standards (MEPS) and mandatory performance labelling required on a range of appliances.

- increasingly water efficient appliances, including showerheads and washing machines, which impact on gas usage for hot water
- a national insulation program which will eventually result in reduced usage of gas for heating
- a range of energy efficiency policy measures including rebates for energy efficient hot water systems including promotion of solar and heat pump water heaters.

Most of these programs are expected to result in reduced energy usage. However some, such as the NSW Residential Rebate Program which provides rebates for replacing electric hot water systems with solar or high efficiency gas, may increase penetration of gas appliances.

4.1.7 Structural changes in the Australian economy and manufacturing industry

The past decade has seen a continuation of a significant structural shift in economic growth from manufacturing to services and also, as a result of globalisation and a high Australian dollar, Australia has become less competitive in manufacturing and has reduced output or reduced growth of output in some industries, including textile, clothing and footwear and iron and steel[5]. While output of some sectors of the Australian economy have grown relatively rapidly, including the energy intensive non-ferrous metals and non-metallic mineral products, overall there has been a reduction of energy intensity of the economy over the period 1990 to 2006 of about 0.7% pa[6], mostly due to structural changes rather than real intensity reductions.

The structural shift to less energy intensive growth differs significantly between states, being more significant in Victoria, NSW and South Australia, and less so in Queensland, Western Australia and the Northern Territory.

4.1.8 Demographics

A key driver for the residential market is the change in customer numbers over time. For the gas market this is made up of new connections due to population increases (from both natural causes and immigration) and increasing penetration of gas into existing households (electric to gas conversions).

The tariff market is likely to be driven by a combination of customer number growth and changes to average usage per customer. Population growth over recent years has been relatively strong, due to the combination of increased fertility and high immigration levels. MMA has assumed that the recent levels of population growth continue for a number of years but then reduce slightly.

5 S Sandu and A Syed, "Trends in energy intensity in Australian industry", ABARE Research report 08.15, December 2008.

6 Ibid, based on activity growth of 3.2% pa and energy growth of 2.5% pa.

4.1.9 Impacts other than efficiency on average usage per customer

In addition to the appliance energy efficiency changes and policies discussed above, a myriad of other factors have impacted the residential market over the past several years including:

- reducing household size (i.e. fewer people per dwelling), although this reduction appears to have become muted in recent years, possibly due to increased fertility and reducing housing affordability
- increased penetration of reverse cycle air conditioners and their use for heating as well as cooling
- the ratio of separate houses to multi-units
- size of new homes
- aging of the population
- increasing affluence of the population
- weather and climate, including the effect of global warming on gas usage in space and water heating.

Some of the above will have positive impacts on gas usage in households, some will have negative impacts; it is very difficult to quantify exactly the impacts of each. Without a great deal of additional data, often all that can reasonably be quantified is the overall direction of recent trends. Recent trends (including the impact of energy efficiency) have shown reduced average gas consumption per residential customer of between -0.5% and -2% p.a. across Eastern Australia.

We expect that, on balance, there will be an increase in gas customers over time, but that the average usage per customer will reduce.

4.2 Non-generation demand

4.2.1 Approach

Non-generation demand comprises the residential, commercial and industrial sectors. For this study MMA has relied upon the GSOO 2009[7] demand forecasts prepared by Core Energy Group and MMA. The Queensland demand forecasts have been reviewed and updated in line with the changes in economic outlook since the demand forecasts in the GSOO 2009 were prepared. The non-generation demand forecasts in other markets have not been updated.

4.2.2 Queensland

The non-generation Queensland market is characterised by a number of large, energy-intensive projects. A number of the most significant projects are listed in Table 4-1.

Growth of usage is largely dependant on the growth of these and similar new projects. The key gas-related considerations for such projects are:

- any remaining impact of the GFC on commodity prices and demand
- the effect of greenhouse gas mitigation measures (e.g. CPRS) on the relevant industries
- the price of gas versus that of other fuels
- international competitiveness, including the value of the Australian dollar
- locational considerations

Most of these have been discussed in section 4.1. Locational considerations take into account whether the plant is best located in central Queensland or another location in Queensland, Australia or overseas.

4.2.2.1 Impact of the GFC and changed greenhouse reduction measures

As discussed in section 2.3.1, the Australian economy, and in particular the resources sector, has rebounded more quickly than expected as a result of continued growth in Asia and the outlook for commodities is now positive.

With all else being equal, it would be expected that new projects and expansions would be delayed by only about 2 years, a year or so less than previously expected in most cases. However, the impact of uncertainties about the introduction and timing of measures to reduce greenhouse emissions, referred to as CPRS here, need also to be taken into account. As delay to the introduction of a price on carbon will adversely affect the economics of cogeneration, the uncertainty about CPRS may result in a continued delay to cogeneration plants which have not yet been committed.

The expected impacts are discussed under each scenario below.

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[7] GSOO Demand Forecast Methodologies, available at: http://aemogas.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=1049&doc_id=5405

Table 4-1 Queensland major gas using projects

Zone	Company	Use of gas[8]
Brisbane area	BP refinery (Bulwer Island)	petroleum refining
	Incitec Pivot	ammonia and urea
Gladstone area	QAL	alumina refining
	Rio Tinto	alumina refining
	Orica (Yarwun)	ammonium nitrate and sodium cyanide
	QMag (Rockhampton)	dead-burnt magnesia
	Boyne Island	aluminium smelting
	Queensland Nitrates (Moura)	ammonia, nitric acid and ammonium nitrate
Townsville region	Queensland Nickel	Nickel refining
	Incitec Pivot (Moranbah, under construction)	ammonium nitrate
	Chalco Alumina (Abbot Point, proposed)	alumina refining
Mt Isa	Xstrata	Copper and lead smelting
	Incitec Pivot	phosphates
	BHP Billiton (Cannington)	silver/lead mining
	Barrick (Osborne)	copper/gold mining

Low scenario

Under the low economic growth case scenario, commodity prices remain relatively weak and there is also a relatively weak carbon price. As a result, resource and fuel switching projects develop more slowly than in the medium and high economic scenarios. However, under this scenario gas prices are low, resulting in the prospect of production of ammonia from gas (rather than its import from other parts of Australia or from overseas, for ammonium nitrate production. Under this scenario we consider such an outcome to be feasible from about 2015.

[8] Includes on-site generation for many users

Medium scenario

Under this scenario the impacts of the GFC are expected to be largely resolved by 2011 with moderate to strong growth in resource projects over the period. Due to the uncertainty about greenhouse gas reduction targets, cogeneration (or fuel switching in boilers) is delayed a little, but as carbon prices increase there will be an imperative to improve carbon efficiency.

High scenario

Under the high economic growth case scenario, commodity prices are higher than in the medium case and there is a higher price on carbon. While this augurs well for both resource projects/expansions and fuel switching for cogeneration/steam generation, the improved prospects for gas usage are offset somewhat by the higher gas price. Nevertheless, the outlook for gas usage in central Queensland is significantly more optimistic than in the medium case.

4.2.3 Summary on non-generation demand in all markets

Table 4-2 to Table 4-4 summarise the non-generation demand projections used in this study. Where the high scenario projections are lower than other scenarios this is due to the greater efficiency gains assumed in the high scenario. Gas use for generation in Mt Isa is included in non-generation demand because Mt Isa is not part of the National Electricity Market.

Table 4-2 Low scenario utility demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	108	207	41	3	49	4	30	33	0
2011	109	210	42	3	51	4	40	33	1
2012	110	211	42	3	52	10	44	33	2
2013	110	214	43	3	52	10	48	34	2
2014	109	218	44	4	53	10	48	33	2
2015	108	221	44	4	54	10	55	33	2
2016	108	224	44	4	54	10	70	29	2
2017	108	226	44	5	55	10	78	31	2
2018	108	228	45	5	56	10	78	31	2
2019	108	231	45	5	56	10	78	32	2
2020	108	233	45	5	57	10	78	33	2
2021	109	236	45	5	56	10	78	32	2
2022	109	238	46	5	58	10	78	33	2
2023	109	240	46	5	58	10	78	33	2
2024	109	242	46	5	59	10	78	33	2
2025	109	245	46	5	59	10	78	33	2
2026	109	248	47	5	59	10	78	33	2
2027	109	251	47	5	60	10	78	33	2
2028	110	254	47	5	61	11	78	33	2
2029	110	257	48	5	62	11	79	33	2
2030	110	260	48	5	62	11	79	33	2

Table 4-3 Medium scenario utility demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	109	207	41	3	49	4	30	37	0
2011	110	211	43	3	51	4	41	38	1
2012	111	212	43	3	52	10	44	39	2
2013	111	216	43	4	53	10	48	41	2
2014	112	220	44	4	54	10	63	40	2
2015	112	224	45	4	55	10	63	39	2
2016	113	227	46	5	56	17	74	35	2
2017	114	230	46	5	57	17	84	37	2
2018	114	232	46	5	57	17	84	37	2
2019	115	235	47	5	58	17	85	38	2
2020	115	238	58	6	59	17	100	40	2
2021	115	241	63	6	59	25	100	40	2
2022	116	244	64	6	60	25	100	41	2
2023	116	246	64	6	61	25	100	41	2
2024	116	249	64	6	62	25	100	41	2
2025	117	253	65	6	62	25	100	41	2
2026	117	257	66	6	63	25	100	41	2
2027	117	260	66	6	64	25	100	40	2
2028	117	264	67	6	65	25	101	40	2
2029	118	267	67	6	66	25	101	40	2
2030	118	271	68	6	66	25	101	40	2

Table 4-4 High scenario utility demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	110	208	41	3	49	4	30	37	0
2011	111	212	43	3	51	4	41	40	1
2012	112	214	43	3	53	10	45	41	2
2013	112	217	44	4	53	10	63	42	2
2014	113	222	45	4	55	10	65	46	2
2015	115	227	46	5	56	19	78	16	2
2016	116	230	47	5	57	19	89	16	2
2017	116	234	47	5	58	21	97	22	2
2018	116	237	59	6	43	21	104	21	2
2019	116	240	64	6	44	21	105	21	2
2020	115	243	65	6	45	44	112	21	2
2021	115	247	65	6	45	51	120	21	2
2022	115	250	66	6	47	51	131	21	2
2023	115	253	66	6	48	51	142	21	2
2024	114	256	67	6	48	51	150	21	2
2025	114	261	68	7	49	74	157	27	2
2026	114	265	68	7	49	74	158	27	2
2027	113	270	69	7	51	74	158	27	2
2028	113	274	70	7	52	74	159	27	2
2029	113	278	71	7	53	74	159	27	2
2030	113	282	71	7	54	80	159	28	2

4.3 Gas demand for power generation

Projected gas demand for power generation has been derived using the same methodology that MMA applied to GSOO 2009 projections, for which the scenario assumptions are consistent with our scenarios.

4.3.1 Methodology

The GPG projections derived for this study were developed utilising MMA's NEM model having regard to the renewable and abatement markets for the Gas Electricity Certificates (GEC) in Queensland, the NSW Greenhouse Abatement Certificates (NGAC), the Renewable Energy Certificates (REC), and of course, the carbon market expected to emerge from the impending CPRS imperative. This model is based on the Strategist probabilistic market modelling software, licensed from Ventyx. Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, MMA partitions Queensland into four zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns in Queensland. These constraints and marginal losses are projected into the future based on past trends.

4.3.1.1 Strategist methodology

Average hourly pool prices and weekly sub period dispatch (e.g. weekly aggregate peak and off peak dispatch) are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 4-1 and the MMA modelling procedures for determining the timing of new generation and transmission resources and bid gaming factors are presented in Figure 4-2.

We have used the PROVIEW module of Strategist to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However, due to computational burden and structural limitations of the Strategist package, it is not feasible to complete in one analysis:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation)
- A review of the contract positions and the opportunity for gaming the spot market prices

Figure 4-1 Strategist Analysis Flowchart

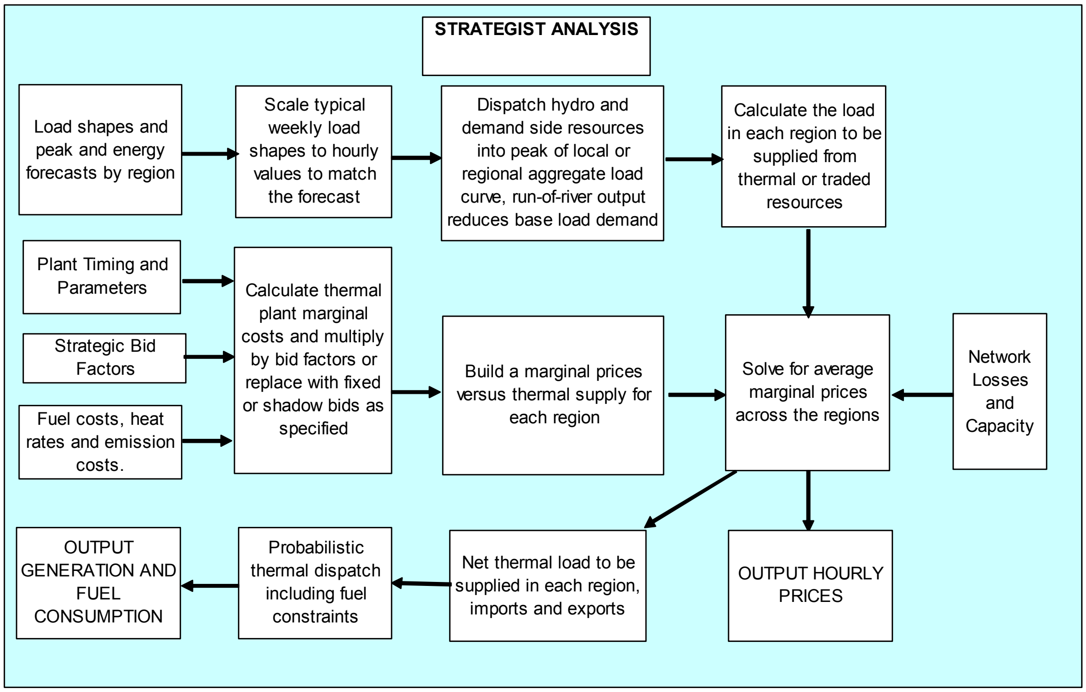
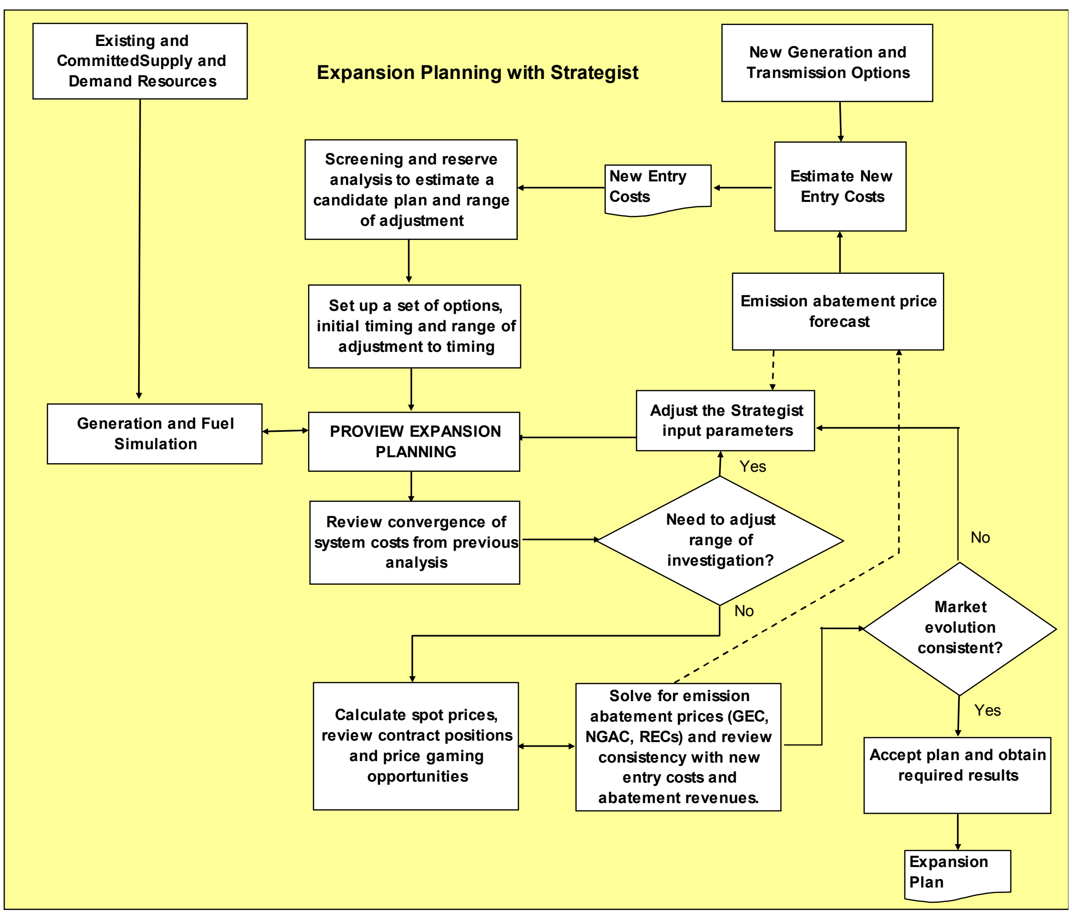


Figure 4-2 MMA Strategist Modelling Procedures



We therefore conduct a number of iterations of PROVIEW to develop a workable expansion plan and then refine the expansion plan to achieve a sustainable price path applying market power where it is apparent and to obtain a consistent new entry plant mix.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded. Such variations occur during thunderstorms, to enhance system security, and during transmission line outages.

Bids are generally formulated as multiples of marginal cost and are varied above unity ratio to represent the impact of contract positions and the price support provided by dominant market participants. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model. The modelling of Smithfield allows for the typical peak and off-peak dispatch levels having regard to the cogeneration requirements.

4.3.1.2 Other methodological aspects

The basic methodology underlying any projection of gas demand for power generation is to develop a credible wholesale electricity price forecast. The reason being threefold: (i) the electricity price is driven by the supply/demand balance, and therefore determines the dispatch of existing gas-fired plant; (ii) it also provides the signal for new (potentially gas-fired) generation plant to enter the market; and (iii) in light of the impending CPRS, it also determines an efficient retirement time frame for incumbent coal-fired plants, whose capacity will potentially be replaced by gas-fired generation sources.

Even though the gas demand projections were developed having regard to the regional pool prices, we do not present these price outputs here since they are beyond the scope of the present study.

The simplifications in bidding structures described above and the way Strategist represents inter-regional trading results in slight under-estimation of the expected prices because:

- All the dynamics of bid gaming over the possible range of peak load variation and supply conditions are not fully represented.
- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very

high price outcomes with quite low probability under unusual demand and network conditions.

- Marginal prices between regions are averaged for the purposes of estimating inter-regional trading resulting in a tendency to under-estimate the dispatch of some intermediate and base load plants in exporting regions such as Gladstone Power Station (GPS) in Central Queensland and Hazelwood in Victoria.

However, overall corrections can be made where these measures are important and in any case the error in modelling is comparable to the uncertainty arising from other variable market factors such as contract position and medium term bidding strategies of portfolios.

A key assumption for gas use in these scenarios is the entry timing for "clean coal" technology based on carbon sequestration. Under the carbon prices assumed in this study, clean coal displaces gas as the lowest cost generation option after it becomes available, which is assumed to be in 2024 to 2026 depending on the scenario. Gas use for generation declines in most zones in all three scenarios after 2025.

4.3.2 Projections

Gas for generation projections are listed in Table 4-5 to Table 4-7. Gas use for generation in Mt Isa is included in non-generation demand because Mt Isa is not part of the National Electricity Market.

Table 4-5 Low scenario generation demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	33	19	68	8	18	11	0	0	38
2011	29	15	58	1	16	8	0	0	38
2012	26	17	62	0	23	6	0	0	61
2013	31	26	65	1	25	7	3	0	71
2014	33	42	75	3	33	9	9	0	77
2015	34	39	83	3	40	11	9	0	75
2016	40	26	98	4	41	11	8	0	77
2017	44	24	97	4	39	11	9	0	71
2018	42	34	96	5	38	9	9	0	68
2019	41	54	81	2	34	11	9	0	67
2020	39	51	83	2	34	15	9	0	68
2021	43	58	85	2	35	17	9	0	70
2022	44	65	88	3	36	19	9	0	72
2023	51	76	89	3	39	21	9	0	73
2024	55	84	91	4	43	23	9	0	78
2025	60	100	93	5	51	24	8	0	84
2026	63	109	96	4	54	25	9	0	86
2027	64	97	93	8	46	21	9	0	76
2028	63	90	90	9	43	18	8	0	73
2029	61	88	86	9	37	16	9	0	71
2030	64	86	76	8	34	16	9	0	72

Table 4-6 Medium scenario generation demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	32	17	58	1	17	8	0	0	40
2011	33	26	62	0	35	7	0	0	67
2012	32	31	67	1	36	8	3	0	83
2013	33	42	76	3	38	9	9	0	93
2014	34	39	85	4	44	12	9	0	87
2015	40	26	106	6	46	12	8	0	86
2016	45	24	105	5	46	12	9	0	84
2017	42	34	106	6	44	9	9	0	88
2018	41	55	91	3	34	11	9	0	116
2019	39	55	93	3	34	16	9	0	136
2020	45	66	96	3	35	17	9	0	140
2021	48	74	101	3	36	20	9	0	149
2022	57	91	103	4	39	25	9	0	155
2023	63	102	107	5	43	37	9	0	163
2024	70	128	109	7	53	44	8	0	176
2025	72	137	115	6	56	63	9	0	173
2026	67	107	106	11	46	62	9	0	140
2027	63	93	103	12	43	54	8	0	131
2028	61	88	94	11	37	47	9	0	126
2029	64	86	80	10	34	48	9	0	126
2030	67	85	73	12	38	57	8	0	134

Table 4-7 High scenario generation demand projection (PJ)

	NSW	Vic	SA	Tas	Bne	T'ville	Glad	Mt Isa	Kogan
2010	29	24	58	1	18	8	0	0	50
2011	31	36	66	0	40	7	0	0	86
2012	37	39	75	1	47	9	3	0	106
2013	34	45	89	4	77	9	9	0	116
2014	38	41	107	4	97	12	9	0	117
2015	45	28	136	6	102	13	8	0	126
2016	49	25	130	5	96	14	9	0	145
2017	44	37	119	7	86	10	9	0	155
2018	41	61	92	3	45	14	9	0	179
2019	40	61	100	3	48	30	9	0	192
2020	47	81	105	3	61	45	9	0	188
2021	55	97	109	4	79	55	9	0	195
2022	68	126	104	4	108	61	9	0	196
2023	76	137	117	5	129	69	9	0	199
2024	80	148	127	7	142	73	8	0	210
2025	73	152	119	7	146	76	9	0	206
2026	71	130	104	15	117	62	9	0	174
2027	76	111	98	17	103	54	8	0	160
2028	67	101	90	17	84	47	9	0	152
2029	66	91	80	15	73	48	9	0	153
2030	83	94	74	16	88	57	8	0	148

4.4 Aggregate domestic projections

Aggregate domestic projections for the three scenarios are illustrated in Figure 4-3. The average demand growth rates in each scenario are: low, 2.2%; medium, 3%; and high, 3.6%. Domestic zonal aggregate projections for the Medium Scenario are shown in Figure 4-4.

Figure 4-3 Aggregate Eastern Australian domestic demand projections

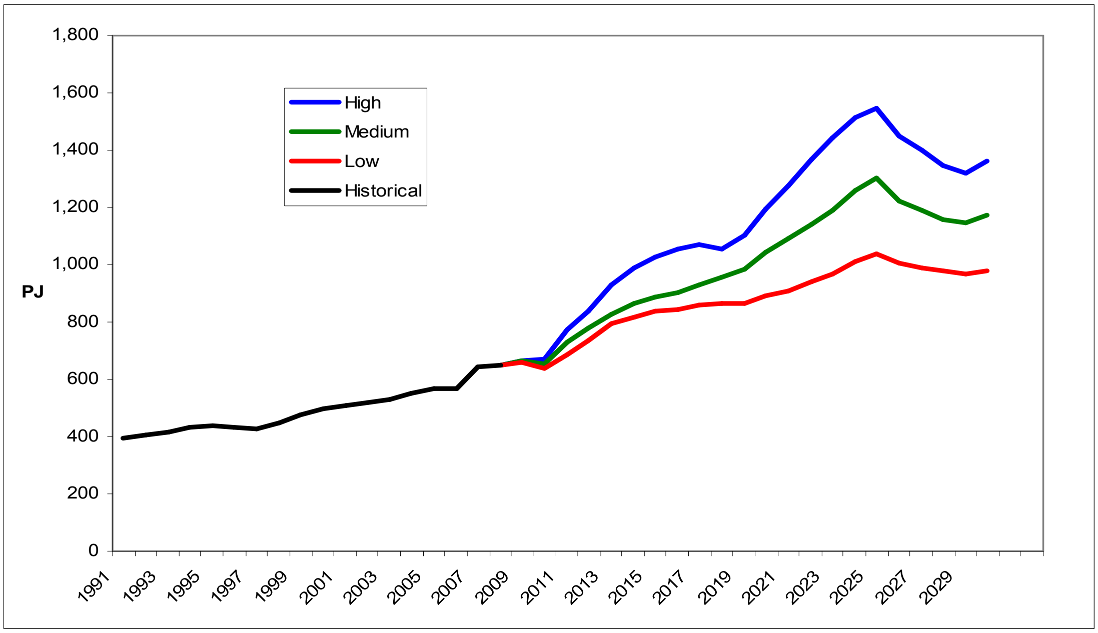
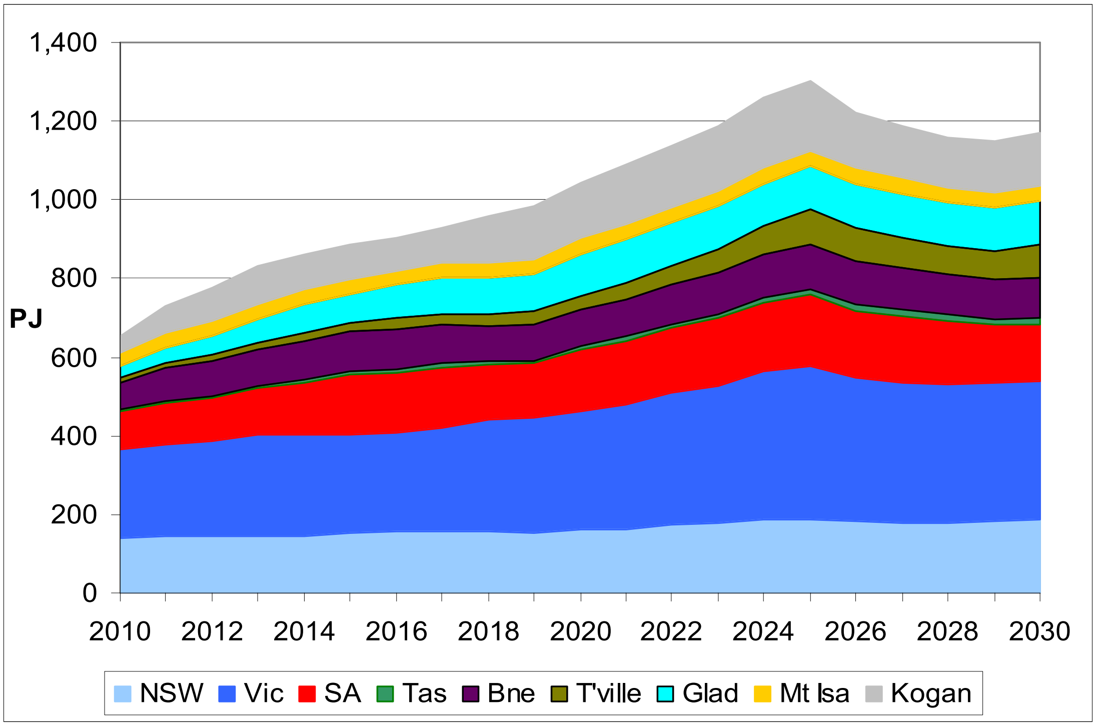


Figure 4-4 Domestic zonal demand projections, Medium Scenario



4.5 LNG exports from Gladstone

4.5.1 Introduction

Eight proposals to convert Queensland CSG to LNG for export to Asian and other markets have been put forward since 2007. The scale of these developments, which envisage exports reaching several multiples of domestic demand by the 2020s, suggests that they may have a material impact on the Eastern Australian Gas Market. The status of the proposals has continued to develop, though as yet none have passed the final investment decision (FID) stage and become fully committed. Project timing therefore remains uncertain, as discussed in detail below.

Three proposals appear unlikely to proceed in the foreseeable future:

- The small scale (0.5 Mtpa) SUN LNG project, the proponent of which is now part of BG Group
- The LNG Impel third party LNG project for which no progress has been reported
- The Energy World Corporation project based on Adavale Basin CSG, to be exported from Abbot Point and/or Hay Point. No CSG resource/reserve estimates have been released for Adavale Basin hence the project's prospects are extremely uncertain

In addition, following the takeover offer for Arrow by Shell/PetroChina that has support of the Arrow Board, Arrow has withdrawn its offer to supply gas to the (2x1.2 Mtpa) LNGL project at Fishermans Landing, so that its gas resources can be focussed on the larger Shell proposal. LNGL has recently received environmental approval for the project from the Queensland Government and is currently seeking alternative gas supply sources.

4.5.2 Major projects

The structures of the four major LNG projects are summarised in Table 4-8 and their key parameters are detailed in Table 4-9 . Each 3-4 Mtpa train will use about 220 PJ of gas per year (600TJ/day) and LNG buyers will require a dedication of at least 15 and probably 20 years of 2P reserves, i.e. up to 4400 PJ, before committing to purchase, unless the supply is backed up other LNG sources in the supplier's portfolio.

GLNG and QCLNG are both anticipating approval of their environmental management proposals by June 2010 – APLNG has only recently submitted its proposal and CSCSG has yet to submit. Based on this, their customer lists and FID targets, GLNG and QCLNG are most likely to reach commitment first. This is extremely important as under many scenarios it is unlikely that customers will be found for all the trains with the announced timing and it is also probable that labour constraints and more general resource constraints will prevent more than one train from starting construction each year.

Table 4-8 Queensland LNG major project structure

Project	Trains No. x Mtpa	Date announced	Participants	Participation Upstream (Production)	Participation Downstream (Liquefaction)
Gladstone LNG	3x3-4	18 Jul 07	Santos	60%	60%
(GLNG)			Petronas	40%	40%
Queensland Curtis LNG (QCLNG)	3x3-4	1 Feb 08	Queensland Gas Company (wholly owned by BG Group)	100%	100%
Australia Pacific LNG	4x4.5	8 Sep 08	Origin Energy	50%	50%
(APLNG)			Conoco Phillips	50%	50%
Shell/Petrochina	4x3-4	16 Feb 09[9]	Shell	50%	50%
(CSCSG)			PetroChina	50%	50%

Table 4-9 Queensland LNG project key parameters

Project	Committed Customers (HoA or MoU) (Mtpa)	Uncontracted 2P Gas Reserves 1/1/10 (PJ)	Expected FID	Train start-up schedule
GLNG	Petronas (2.0)	3,854	H2 2010	2014 2015 or later 3rd later
QCLNG	CNOOC (3.6) Tokyo Gas (1.2) Singapore (1.5) Chile (1.7)	3,829	H2 2010	Late 2013 Mid 2014 3rd later

[9] The original date of a Shell proposal for a 4x3-4 Mtpa project on Curtis Island. The JV bid for Arrow was announced on 8 March 2010.

Project	Committed Customers (HoA or MoU) (Mtpa)	Uncontracted 2P Gas Reserves 1/1/10 (PJ)	Expected FID	Train start-up schedule
APLNG	N/a	5,336	Late 2010	Late 2014 Mid 2015 3rd&4th later
CSCSG	PetroChina (N/a)	4,403	2012	2015? Others later

What the projects will commit to remains uncertain however. QCLNG and APLNG have both indicated that their initial commitment will be to two trains, to get the benefit of economies of scale in construction. GLNG has suggested it will proceed to FID on a single train but is widely believed to also prefer commitment to two. However it appears that none of the projects can commit to two trains with the above FID timing because they don't and probably won't have sufficient reserves, as explained in the following paragraph.

At the beginning of 2010 each of the four LNG proponents, GLNG, BG Group, APLNG and Arrow/Shell, had approximately 4,000 to 5,000 PJ of uncontracted 2P reserves (refer to Table 5-5), sufficient for commitment to a single 3.5 Mtpa LNG train. At current annual rates of reserves growth of 1,000 to 2,000 PJ per proponent (refer to reserves discussion in section 5.1) it will take until 2012-2014 for each to accumulate enough reserves to commit to two trains.

Options to meet their FID timetables appear to be:

1. Commit on the basis of one train only
2. Buy gas from the other proponents. This is not as unlikely as it sounds and on 25th February APLNG announced that it had entered conditional GSAs for the sale of gas to BG Group (QCLNG) from jointly owned tenements. The sale contemplates a total volume 640 PJ over 20 years.
3. Consider combining projects. This idea has resurfaced in recent weeks with analysts suggesting that the projects would benefit from merging[10]. The logic of this option is now driven by the need to improve project economics under the RSPT (see below) and is reinforced by the likely limitation on rates of construction – by combining projects, proponents can limit the risk of having to defer their start-up.

[10] Santos gas project faces delays over tax, sales: analysts. The Age May 13 2010.

4. Convince buyers to accept lower levels of reserves support or rely on other sources in their LNG portfolios to support customer agreements.

The announcement of the Resources Super Profit Tax (RSPT) on May 2nd has added further uncertainty regarding timing. Santos has stated[11] that it will extend the deadline for FID to late 2010, without affecting its ability to meet 2014 LNG delivery, in order to examine the impact of RSPT on the GLNG project. Industry analysts however believe that timing may be pushed back to 2015.

For the purposes of this study we have used three LNG development projections similar to the scenarios prepared in 2009 for the Australian Energy Market Operator (AEMO) by MMA. The high scenario assumes that the highest economic construction rate is one train per year, and that global LNG demand will support this growth rate. Medium and low scenarios are related to lower global LNG demand growth rates. Details of global demand are provided in "GSOO Aggregated Demand Forecasts"[12].

Details of assumed project timing are presented in the tables below. Development has been allocated to specific projects to meet aggregate projections. It is noted that the reserves for each project are required to be in the 2P category some four years in advance of start-up, to support FID.

Table 4-10 High Scenario Projected LNG Train Start-up Timing (Mtpa) and Cumulative Reserve Requirement (PJ)

	2014	2015	2016	2017	2018	2019	2020
Project 1	3.5	3.5					
Project 2			3.5	3.5			
Project 3					3.5		3.5
Project 4						3.5	
Total	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Cumulative	3.5	7	10.5	14	17.5	21	24.5
Cum Reserves	4,433	8,867	13,300	17,733	22,167	26,600	31,033
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1		3.5				3.5	
Project 2			3.5				3.5
Project 3				3.5			
Project 4	3.5				3.5		
Total	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Cumulative	28	31.5	35	38.5	42	45.5	49
Cum Reserves	35,467	39,900	44,333	48,767	53,200	57,633	62,067

[11] Annual General Meting of Santos 2010. CEO's Address
[12] http://aemogas.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=1049&doc_id=5405

Table 4-11 Medium Scenario Projected LNG Train Start-up Timing (Mtpa) and Cumulative Reserve Requirement (PJ)

	2014	2015	2016	2017	2018	2019	2020
Project 1	3.5	3.5					
Project 2				3.5			
Project 3						3.5	
Project 4							
Total	3.5	3.5	0	3.5	0	3.5	0
Cumulative	3.5	7	7	10.5	10.5	14	14
Cum Reserves	4,433	8,867	8,867	13,300	13,300	17,733	17,733
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1							
Project 2							3.5
Project 3	3.5						
Project 4			3.5		3.5		
Total	3.5	0	3.5	0	3.5	0	3.5
Cumulative	17.5	17.5	21	21	24.5	24.5	28
Cum Reserves	22,167	22,167	26,600	26,600	31,033	31,033	35,467

Table 4-12 Low Scenario Projected LNG Train Start-up Timing (Mtpa) and Cumulative Reserve Requirement (PJ)

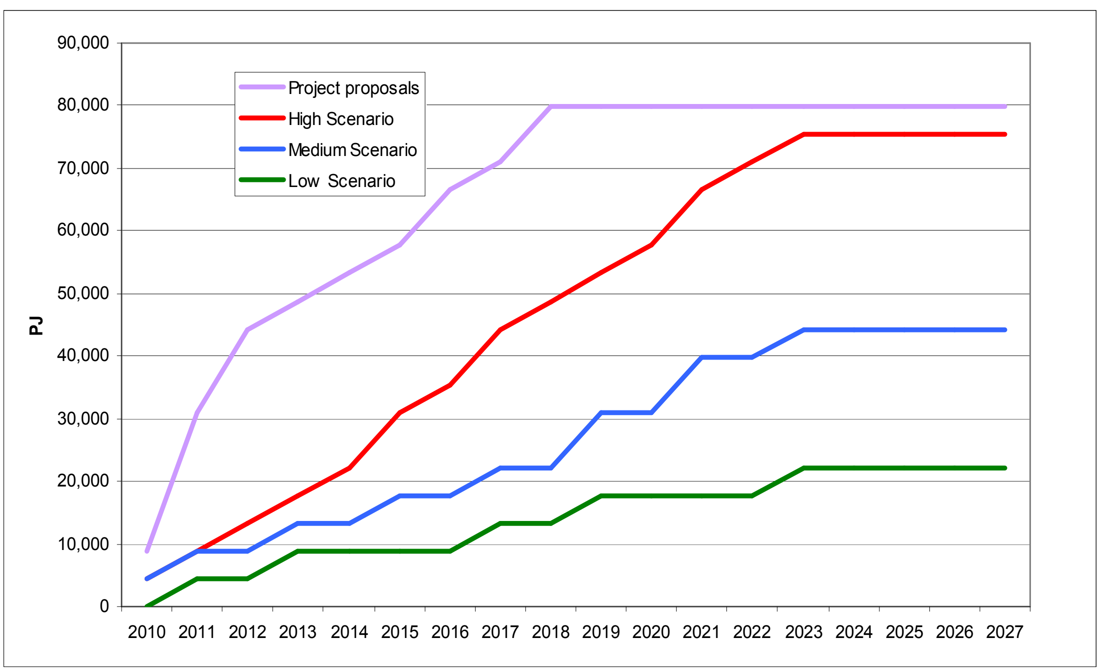
	2014	2015	2016	2017	2018	2019	2020
Project 1		3.5		3.5			
Project 2							
Project 3							
Project 4							
Total	0	3.5	0	3.5	0	0	0
Cumulative	0	3.5	3.5	7	7	7	7
Cum Reserves	0	4,433	4,433	8,867	8,867	8,867	8,867
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1							3.5
Project 2	3.5		3.5				
Project 3							
Project 4							
Total	3.5	0	3.5	0	0	0	3.5
Cumulative	10.5	10.5	14	14	14	14	17.5
Cum Reserves	13,300	13,300	17,733	17,733	17,733	17,733	22,167

The LNG export scenarios differ from the GSOO scenarios as follows:

- High scenario – development of one 3.5 Mtpa train per year is extended to 2027
- Medium scenario – initial development is two consecutive trains (one in GSOO), reflecting possible BG outcome, followed by one train every two years
- Low scenario – initial train in 2015 (2017 in GSOO) followed by one train every three years

The timing of gas reserve commitments for the project proposals as they stand and for each of the scenarios is illustrated in Figure 4-5. All estimates are based on the assumption of full 20 year commitments four years before first production. Commitments could be earlier if reserves for multiple trains are all committed at FID. Initial commitments would be reduced if they were for less than 20 years but ultimate commitments would not change. MMA is aware of different views among LNG proponents as to whether buyers will require the full 20 year 2P reserves commitment or whether they will purchase LNG on the basis of a more limited 2P commitment, probably with annual extensions, subject to their satisfaction that the contingent resources are available and will be developed over time.

Figure 4-5 Timing of gas reserve commitments for LNG exports (PJ)



5 GAS SUPPLY

5.1 Reserves and Resources

The gas reserves and resources estimates used in this study have been based upon data supporting[13] estimates prepared in 2009 for the Australian Energy Market Operator (AEMO) by MMA with assistance from RLMS. MMA's report to AEMO, "Gas Reserves Development in Eastern Australia – Forecasts Prepared for the Gas Statement of Opportunities" (GSOO 2009), is available from the AEMO website[14]

The GSOO 2009 provides background material on the gas resource development process and the approaches used to classify gas resources into:

- Commercial reserves (demonstrated reserves that would yield a commercial return at expected prices):
    - Proved reserves (1P)
    - Proved and probable reserves (2P)
    - Proved, probable and possible reserves (3P)
- 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, medium and high estimates)

2P reserve estimates are the most widely quoted, as they form the basis of long-term contracts for gas sales and purchases - a producer's ability to deliver gas under the contract is usually underwritten by demonstrated gas reserves at the proved and probable (2P) level. Reserves equal to the total contract gas quantity are typically dedicated to contracts though 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, for example to maintain a minimum number of years of coverage at all times. In summary, 2P reserves form the basis of commercial contracting and the other estimates are not commonly used for this purpose.

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[13] The GSOO 2009 reserves data is reported at the basin level but was derived at the gas producer level reported here.
[14] http://aemogas.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=1049&doc_id=5188

1P estimates may be used as an indication of the certainty of gas production in the short term and 3Pand 2C estimates are used to indicate the potential for future 2P reserve development.

5.1.1 Historical growth

Historical reserve and resource trends are shown in Figure 5-1 and Figure 5-2. Whereas remaining reserves of conventional gas have been relatively static since the initial discoveries were made in the 1970s, CSG reserves have grown rapidly from a zero base in 1995 to overtake conventional reserves in 2008. It is noted that the apparent lack of growth in 1P and 3P CSG reserves in 2009 may be due to under reporting – values not reported in 2009 have been assumed to remain at 2008 levels.

Figure 5-1 Aggregate conventional gas resources and reserves, Eastern Australia (PJ)

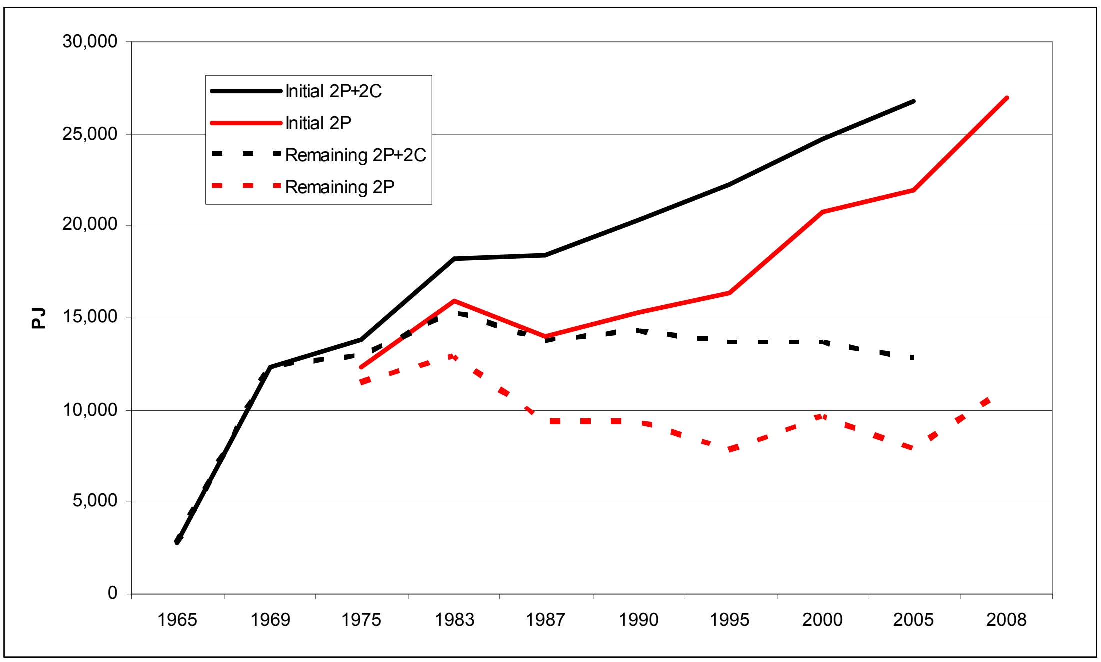
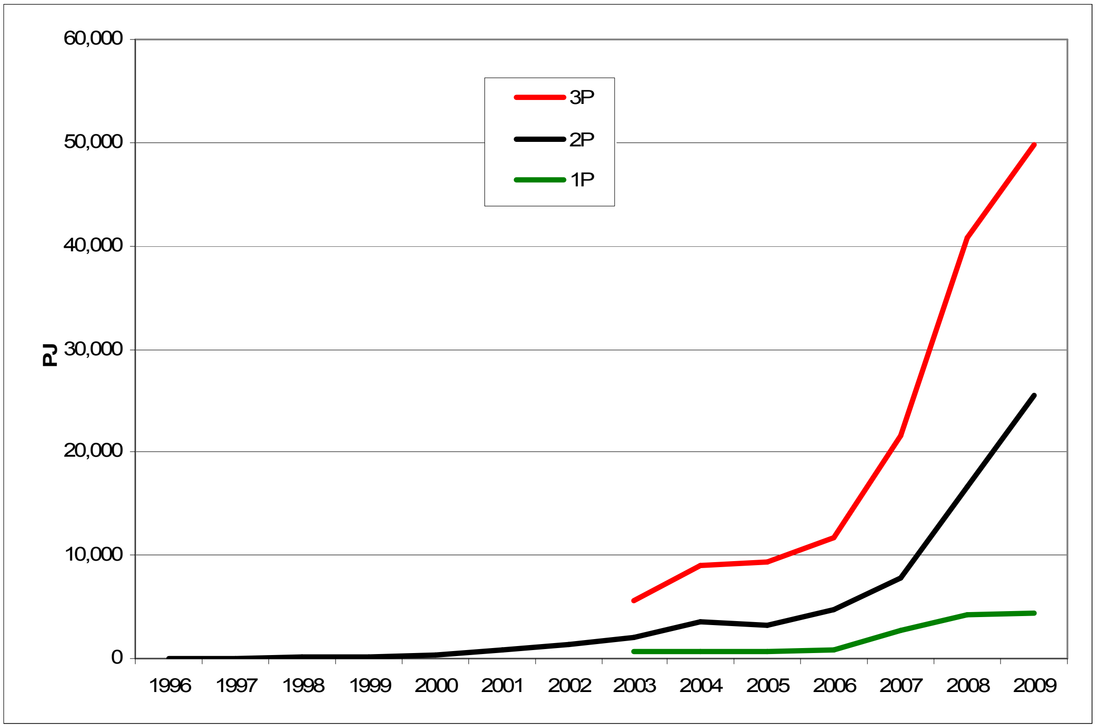


Figure 5-2 Aggregate CSG reserves, Eastern Australia (PJ)



5.2 Conventional reserves and resources as at 1st January 2010

The reserve and resource estimates used for each of the major joint venture producers considered in the study are presented in Table 5-1. They are based on the GSOO 2009 data updated only for the Cooper Basin, for which Santos has recently reported contingent resources of 1,584 PJ of conventional gas and 4,750 PJ of unconventional gas (tight and shale gas and CSG), on a gross, basin-wide, basis. We have assumed that these are 2C estimates. The 1/01/2010 estimates of 2P and 2C are derived from earlier estimates by deducting production and adding "discoveries" implicit in the GSOO 2009 assumptions.

The 2C resources estimates for other basins are based on the methodology derived for the GSOO 2009. It is important to bear in mind that they apply only to conventional resources and that unconventional resources such as tight gas and shale gas in the relevant basins may be considerably larger, as in the Cooper Basin.

Adavale Basin reserves and resources have been omitted on the grounds that the basin went out of production more than five years ago and on the basis of the very low GSOO 2009 reserves and resources estimates, production is unlikely ever to restart. Gunnedah Basin conventional reserves have also been omitted because they are very low.

Table 5-1 Remaining conventional gas reserves and resources as at 1/1/2010 (PJ)

Basin	Joint Venture	2P	2C + Prospective
Gippsland	BHPB-Exxon	6,887	3,933
Gippsland	OMV, Trinity, Santos	624	357
Bass	Origin, AWE	487	205
Otways	BHPB, Santos	288	246
Otways	Woodside, Origin	811	701
Otways	Santos, Beach	416	360
Otways	Origin, Others	8	6
Cooper Eromanga	Santos, Beach, Origin	1,163	1,584
Cooper Eromanga	Others	32	59
Surat-Bowen	All producers	200	706
	Total	**10,917**	**8,158**

Sources: Cooper Basin, Santos presentation," Delivering Transformational Growth", March 2010. Others derived from "Gas Reserves Development in Eastern Australia – Forecasts Prepared for the Gas Statement of Opportunities"

5.3 CSG reserves and resources as at 1st January 2010

5.3.1 Reserves

CSG 2P reserves growth for each of the major joint ventures considered in the study are presented in Table 5-2. The 2007, 2008 and 2009 values are derived from the GSOO 2009, with the exception of Anglo Coal, for which the figures are derived from 2P reserves estimates released by DEEDI[15]. GSOO 2009 data for other JVs has been reconciled with the DEEDI data.

Table 5-2 Remaining CSG 2P reserves as at 1st January (PJ)

Basin	Joint Venture	2007	2008	2009	2010
Sydney	AGL	82	82	82	126
Gloucester	AGL	0	175	175	423
Gunnedah	ESG/Santos	0	185	336	1,520
Clarence Morton	Metgasco/CS Energy	22	247	298	397
Bowen	AGL/Arrow/Shell	500	500	947	1,509
Surat	APLNG	1,374	2,470	5,482	7,266
Surat	BG Group	695	1,786	3,694	4,694
Surat/Bowen	GLNG	1,128	1,344	3,246	4,003
Surat	Arrow/Shell	581	700	1,744	4,648
Bowen	Anglo-Coal	140	137	135	135
Surat	Minors + STO excl GLNG	308	273	491	770
	Total	**4,830**	**7,899**	**16,630**	**25,491**

Source: GSOO 2009, DEEDI and producer websites.

15 http://www.dme.qld.gov.au/zone_files/Petroeum_and_Gas_XLSs/csg_res_06_09.xls

The 2010 values are derived from recent producer reserves statements, as DEEDI will not be releasing data for 1st January 2010 until 1st July 2010. Two groups have not revealed reserve upgrades since 1st January 2009, BG Group and Anglo-Coal. For Anglo-Coal, which is a relatively minor player, we have left the reserve estimates unchanged from 2009 to 2010. For BG Group, a major CSG/LNG participant, we have assumed 1000PJ of net 2P reserve additions during 2010.

It is important to note that:

1. The figures in the table are based on current acreage ownership, i.e. the figures in earlier years include reserves of all companies that were taken over by the JV in subsequent years, so that the growth relates to current acreage.

2. The above are company estimates, most of which have been verified by independent assessors. We have not discounted reserves that have not been verified by independent assessors.

3. Some of the Bowen/Surat Basin estimates are understood to include conventional gas reported separately in Table 5-1. To avoid double counting these conventional gas reserves (200PJ) have been excluded from the total reserve estimates reported in Table 3-1 and Table 5-5.

5.3.2 Resources

Contingent and prospective resource values for 2010 have also been derived from recent producer reserves statements (DEEDI does not publish resource estimates). For the small number of JVs for which we have no 2C estimates, we have substituted the difference between 3P and 2P reserves, this being the best indication of future 2P reserve potential in this case.

Table 5-3 CSG 2C and prospective resources as at 1st January 2010 (PJ)

Basin	Joint Venture	2C	Prospective	Combined
Sydney	AGL	44		44
Gloucester	AGL	370		370
Gunnedah	ESG/Santos	3,053	50,000	53,053
Clarence Morton	Metgasco/CS Energy/Arrow	10,597	3,893	14,490
Bowen	AGL/Arrow/Shell	17,194	18,492	35,685
Surat	APLNG	7,919		7,919
Surat	BG Group	9,654		9,654
Surat/Bowen	GLNG	2,769	10,500	13,269
Surat	Arrow/Shell	8,435	4,326	12,760
Bowen	Anglo-Coal	302		302
Surat	Minors + STO excl GLNG	2,996	10,500	13,496
Galilee	All participants		21,840	21,840
	Total	**63,333**	**119,550**	**161,043**

It is noted that in comparison with the 2009 estimates presented in GSOO 2009:

- 2C resources are approximately 6,000 PJ lower, implying that in net terms approximately 67% of the 9,000 PJ of 2P reserves growth from 2009 to 2010 was derived by conversion of 2C resources, without replacement.
- Prospective resources are approximately 4,000 PJ higher.

5.4 Reserves growth potential

5.4.1 Conventional

The derivation of conventional gas contingent and prospective resources is consistent with their discovery and proving up over a thirty year period (GSOO 2009). Consequently future conventional reserve additions are based on the assumption that the 2C and prospective resources in Table 4-8 are converted to 2P reserves at a steady rate over a thirty year period. To simplify modelling, the unconventional contingent resources in the Cooper Basin are treated as conventional resources in that basin.

5.4.2 CSG

Future growth rates for CSG 2P reserves are constrained by industry capacity to convert resources into reserves and by the total quantum of resources. Recognising that since the first LNG projects were announced in 2007 the industry has had a strong incentive to expand CSG resources as fast as possible, recent reserve additions are taken to be indicative of the industry's maximum capacity to expand the CSG reserves base. Estimates of gross reserve additions in each year are presented in Table 5-4, these being the sum of the net growth reflected in Table 5-2 and gas produced in each year.

Table 5-4 CSG 2P reserve growth rates in the year to 1st January (PJ)

Basin	Joint Venture	2008	2009	2010	Future max
Sydney	AGL	0	14	58	58
Gloucester	AGL	175	0	248	141
Gunnedah	ESG/STO	185	151	1,184	1,184
Clarence Morton	Metgasco/CS Energy	225	51	99	125
Bowen	AGL/Arrow/Shell	0	474	589	532
Surat	APLNG	1,096	3,106	1,898	2,502
Surat	BG Group	1,091	1,954	1,049	1,501
Surat/Bowen	GLNG	216	1,917	772	968
Surat	Arrow/Shell	119	1,065	2,922	1,994
Bowen	Anglo-Coal	N/A	6	8	7
Surat	Minors + STO excl GLNG	N/A	233	293	263
	Total	**3,069**	**8,971**	**9,121**	**9,275**

The maximum future annual 2P reserves growth rates used in our modelling are based on the average growth achieved over the last two years, which appear to better reflect the incentives provided by LNG prospects than does the year to 1st January 2008, with the exceptions of: GLNG (968 PJ figure based on three year average); Sydney Basin (last year's growth under 100% AGL Ownership); Gloucester (average of 3 years growth); Gunnedah (last year's growth which reflects underlying potential); and Clarence Morton (average of 3 years growth).

In modelling future reserves growth the following factors are also taken into account:

1. Cumulative reserves growth is also constrained to levels below current contingent plus prospective resources, consistent with the approach taken in the GSOO 2009 study

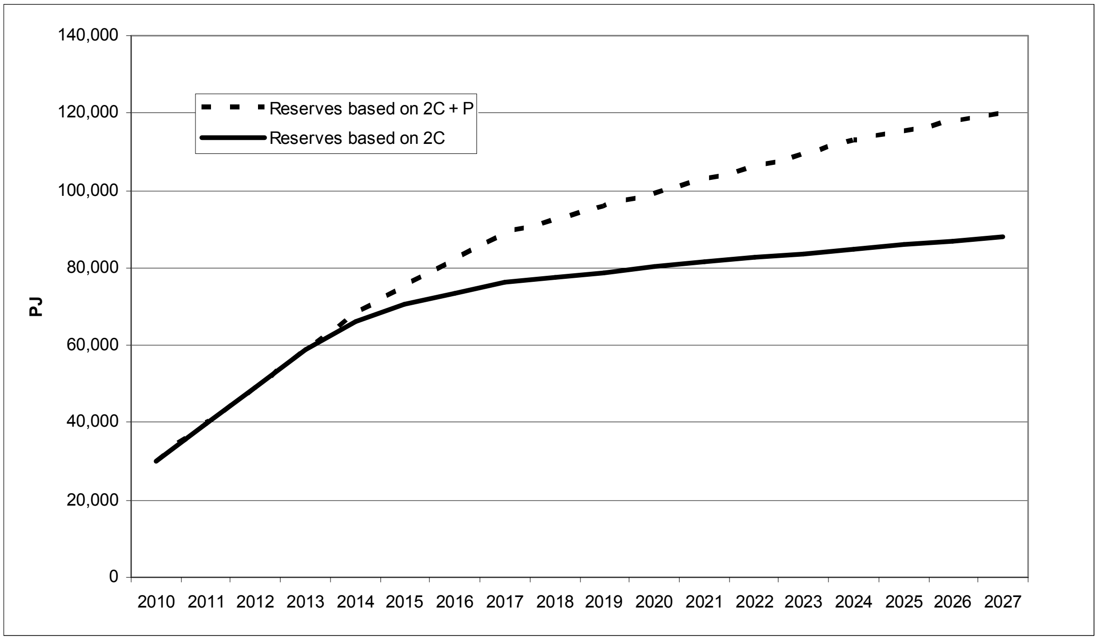
2. No allowance is made for possible declassification of reserves declared 2P at 1st January 2010, because earlier declassifications have already affected historical growth and are therefore built into the growth estimates.

3. Unless LNG developments continue beyond those already announced (refer to section 4.5) we would expect CSG reserve growth to eventually taper off to levels below the maximum achievable. In MMAGas this is effected by setting a target band for reserves dedicated to the domestic market and using this to determine a rate of reserve growth between zero and the maximum that maintains this reserve component in the target band, where possible. If a growth rate greater than the maximum is required, the reserve component will fall below the lower limit of the band.

4. The prospective resources for the Galilee Basin are excluded from consideration because the basin has no 2P reserves history from which to estimate a growth rate.

Figure 5-3 illustrates aggregate uncontracted gross (prior to production) 2P reserves growth at the maximum growth rates consistent with recent growth rates and with cumulative growth capped at either current 2C or 2C plus prospective resources. The reduction in growth rates after 2014 in the 2C case and after 2018 in the 2C + P case is due to individual areas reaching their resource caps. 2P growth rates will be maintained in the longer term only if there is continued growth of prospective resources feeding into contingent resources and reserves, or if prospective resources in the Galilee Basin are developed into contingent resources and reserves.

Figure 5-3 Projected aggregate uncontracted gross 2P reserves with maximum growth assumptions (PJ)



5.5 Reserves committed to GSAs

MMA maintains a data base of Eastern states GSAs, derived largely from information published on buyer/seller websites supported by analysis of industry data provided via the AEMO Bulletin Board and in support of the Victorian gas market. While there are likely to be some GSAs missing from the data base, either because their existence is not on the public record or because we have failed to find it, MMA believes that 95% of the gas volume contracted is accounted for. For many GSAs however only the term and total volume committed are known and annual volumes can only be estimated. The GSAs tabled below include volumes estimated for related party GSAs which can be inferred but have not been publicly revealed, such as between Origin Energy's production and generation divisions, but do not include any LNG related arrangements.

Table 5-5 shows the total contracted and uncontracted volumes, compared with 2P reserves as at 1st January 2010. Projected incremental GSA requirements for the domestic market are depicted in Figure 5-4 and projected incremental reserves requirements for each demand scenario are depicted in Figure 5-5 – the timing of requirements is aligned with first supply from the relevant GSA but the actual commitment of reserves will be at the time the GSA is signed, several years earlier.

Table 5-5 Comparison of 2P reserves and gas contracted as at 1st January 2010 (PJ)

Basin	Joint Venture	2P Reserves	Contracted	Uncontracted
Conventional				
Gippsland	BHPB-Exxon	6,887	2,154	4,733
Gippsland	OMV, Trinity, Santos	624	230	394
Bass	Origin, AWE	487	188	300
Otways	BHPB, Santos	288	138	150
Otways	Woodside, Origin	811	639	171
Otways	Santos, Beach	416	395	22
Otways	Origin, Others	8	0	8
Cooper Eromanga	Santos, Beach, Origin	1,163	569	594
Cooper Eromanga	Others	32	0	32
CSG				
Sydney	AGL	126	108	18
Gloucester	AGL	423	0	423
Gunnedah	ESG/Santos	1,520	0	1,520
Clarence Morton	Metgasco/CS Energy	397	0	397
Bowen	AGL/Arrow/Shell	1,509	306	1,203
Surat	APLNG	7,266	1,931	5,335
Surat	BG Group	4,694	866	3,828
Surat	GLNG	4,003	150	3,853
Surat	Arrow/Shell	4,648	225	4,424
Bowen	Anglo-Coal	135	43	92
Surat	Minors + STO excl GLNG	770	89	682
	Total	**36,208**	**8,028**	**28,179**

Source: MMA estimates

Figure 5-4 Projected domestic incremental GSA requirements (medium scenario, PJ)

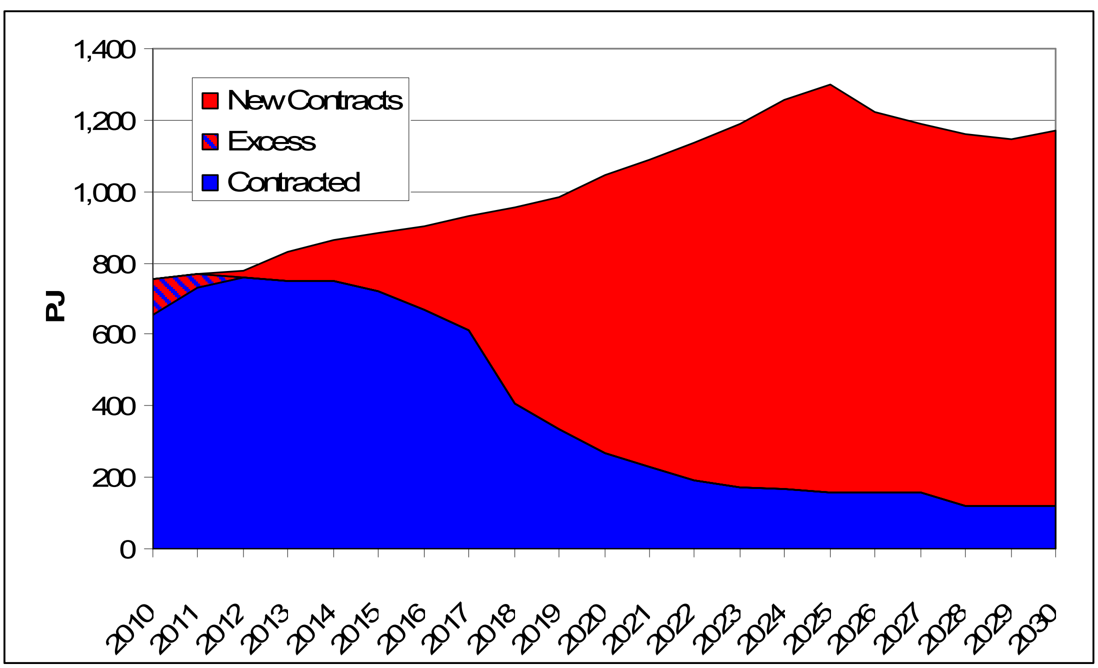
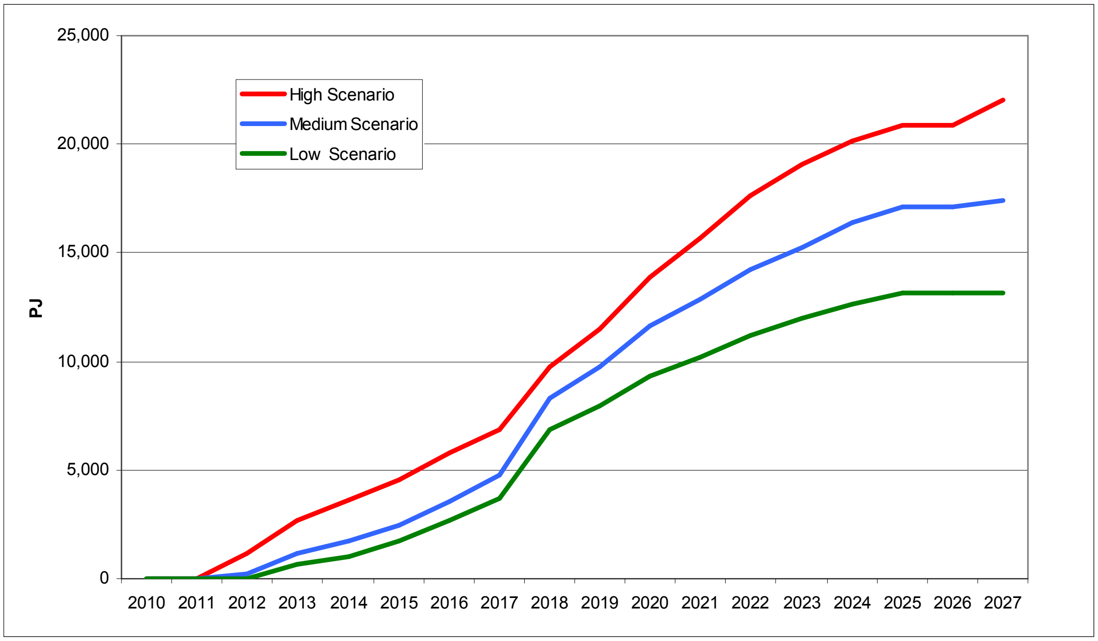


Figure 5-5 Projected incremental reserves requirements for the domestic market (PJ)



5.6 Gas production costs

Information regarding gas production costs is not widely disseminated in Australia. The production cost for declared reserves can be inferred from the fact that they are commercial, provided that the market price at which the reserves test for commerciality has been conducted is known. For the large majority of reserve estimates this market price is not stated however.

For gas in Eastern Australia, where the wellhead market price has always been low in world terms, in the range $3/GJ to $4/GJ in real 2010 dollar terms, it has until recently been reasonable to assume that commerciality meant profitable at that price level or perhaps slightly above if a price rise was forecast. For conventional reserves this remains a reasonable assumption but for CSG reserves being developed for LNG exports, which could sustain higher gas input prices, the possibility of higher price assumptions arises.

It is therefore of interest to note that Origin Energy has recently declared that its reserves estimates are still based on commerciality at the above price level[16], noting that its reserve estimates were based on "economic tests included capital and operating cost estimates based on Origin's current and projected developments together with current market gas prices in eastern Australia (circa $3 per GJ)". Origin also provided a schematic illustration of the relationship between gas prices and economically viable gas reserves.

Santos[17] has indicated that for Cooper Basin conventional resources 55% of original gas in place (OGIP) is 2P at current prices but that at (unspecified) higher prices, a further 20% of OGIP could be classified 2P.

These statements support the concept that current reserves can be produced for $3/GJ to $4/GJ but that some resources will only be declared 2P if the market price supports a higher cost of production. The exact nature of the relationship between gas prices and reserves is likely to be unknown even to gas producers, given the preliminary nature of contingent and prospective resource data.

For the purposes of this study we have therefore considered the effects of two different gas production cost assumptions:

- A base case in which new reserve additions after 2010 can be developed at current costs. This assumption is used with the Low, Medium and High scenario assumptions for other inputs.
- A higher cost case in which 50% of new reserve additions after 2010 can be developed at current costs and 50% can only be developed at a higher cost in the range $5-6/GJ. This case is applied only with the High scenario assumptions for other inputs.

[16] Origin Energy. UBS Resources Conference June 2008.
[17] Santos Investor Seminar 3 June 2008.

5.7 Gas transmission assumptions

The existing network of transmission pipelines depicted in Figure 3-1 in principle enables gas to be transported from any production centre to any major market centre, with the exception of Townsville. Of course in practice there are capacity constraints and difficulties in arranging backhaul but these can be overcome where there is sufficient commercial incentive.

As the cost of delivered gas is made up of approximately 75% wellhead price and 25% transmission price, when matching demand and supply, our focus is more on the wellhead component of supply than transmission and our assumptions regarding pipelines are as follows:

- Existing pipelines are "unconstrained", that is, capacity can be added by further compression or duplication
- Pipeline tariffs continue at current levels/escalation rates
- Uncommitted new pipelines can be added but their projected throughput must be tested to ensure commercial viability.

In the scenarios analysed for this study uncommitted new pipelines have been included as follows:

- Pipelines to convey CSG from the Southern Bowen/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 CPI escalation.
- A modified version of the proposed Queensland-Hunter pipeline, to convey CSG from the Gunnedah and Gloucester Basins north to Wallumbilla and south to Wilton to compete in the broader NSW market. At throughput rates of 50PJ/yr the tariffs for both the north and south sections are estimated at $1.00/GJ escalating at CPI (see below). 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: SWQP- QSNLink-MSP.
- The Lions Way pipeline linking Clarence-Morton CSG production in northern NSW with Brisbane. The pipeline tariff is estimated to be $0.50/GJ with CPI escalation.

5.8 Ramp-up gas

Ramp-up gas is the unavoidable gas produced from LNG project CSG wells prior to LNG plant start-up, owing to the difficulty of shutting-in CSG production. Ramp-up gas management could be achieved by placing it in underground storage or disposing of it cheaply to electricity generators or other users who can take more than their current contracts.

Net quantities likely to be available from each LNG project remain largely unknown but 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 and we therefore view ramp-up gas as 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.

Users able to take advantage of the lower prices will undoubtedly be willing to enter the shorter-term contracts associated with it but we do not see this on its own leading permanently to shorter term contracting and ramp-up gas is unlikely to greatly influence long-term contract prices negotiated now or in the future.

6 GAS DEMAND-SUPPLY AND PRICE PROJECTIONS

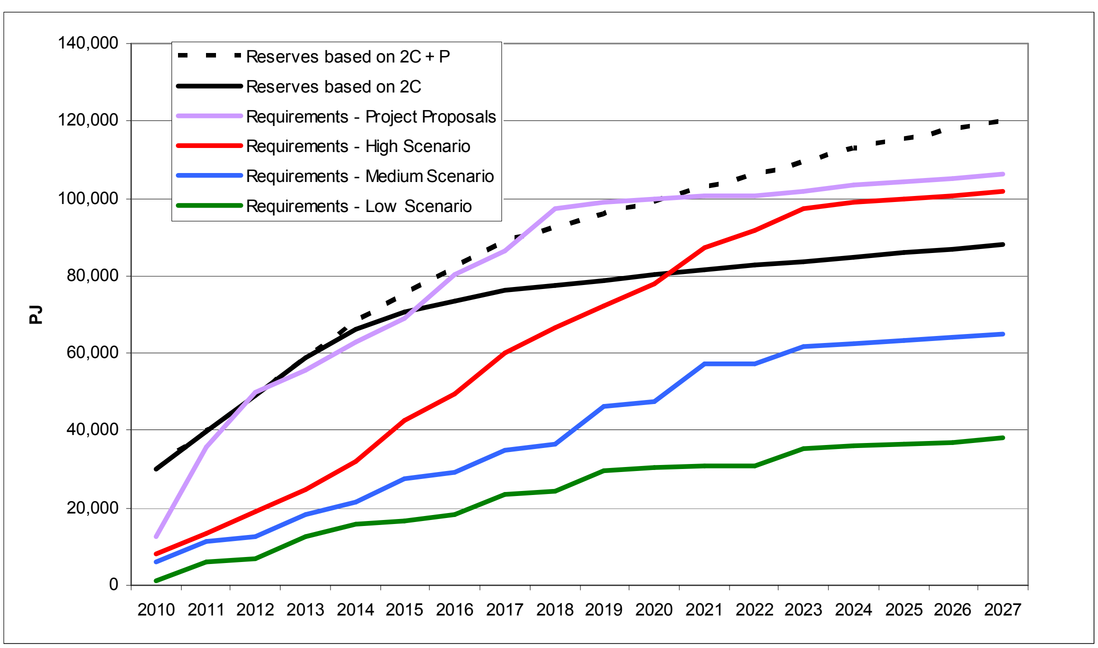
6.1 Aggregate 2P reserve requirements and projections

Combined domestic and LNG reserves requirements based on 20 year 2P commitments (Figure 5-5 and Figure 4-5) are compared with uncontracted 2P gross reserves projections based on maximum growth rates (Figure 5-3) in Figure 6-1 below. The Project Proposals LNG requirements have been combined with High Scenario domestic requirements.

It is clear that the reserve requirements of the Project Proposals would severely test the industry's ability to develop reserves, particularly as some of the reserves, such as those offshore Victoria, are not readily accessible to LNG developments in Gladstone.

The aggregate reserve requirements in the High Scenario however, which MMA believes reflects the highest feasible LNG development rate for reasons other than reserve constraints, can be met more readily, with a steady buffer of over 20,000 PJ of uncontracted gas until 2020. This buffer will be maintained after 2020 only if there is continued growth of prospective resources feeding into contingent resources and reserves, or if prospective resources in the Galilee Basin are developed into contingent resources and reserves.

Figure 6-1 Combined domestic + LNG reserve requirements vs 2P uncontracted gross reserve projections (PJ)



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

Based on the aggregate comparisons for the High, Medium and Low scenarios it would be easy to conclude that there will not be any gas reserve adequacy issues in the short to medium term. However the aggregate projections conceal the current commercial reality that there are four competing major LNG projects, each aiming to meet its own reserves requirements for its planned FID, regardless of the eventual actual timing of their projects. Consequently the volumes of gas available for the domestic market are considerably less than the buffers illustrated.

To obtain a more representative picture than the aggregate one above we have developed detailed demand-supply balances, including price outcomes, for each of the High, Medium and Low scenarios.

6.2 Methodology

The demand-supply balance and price projections for this study have been derived using our proprietary model MMAGas, which replicates the essential features of the Australian wholesale gas market:

- A limited number of gas producers, with opportunities to exercise market power
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Domestic market growth driven by gas-fired generation and large industrial projects.

MMAGas has been developed, over a period of seven years, to provide realistic assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market:

- The "gas market" in MMAGas is the market for medium to long-term GSAs between producers and buyers such as retailers or generators
- MMAGas combines information on gas reserves, gas demand and committed GSAs to estimate the demand for new GSAs and the capacity of each producer to supply them
- Allocation of new GSAs in each market zone to gas producers is based on the assumption that each producer seeks to control its volumes and prices to maximise its profit subject to constraints imposed by its competitors and its capacity to produce
- This competition between producers is represented as a Nash-Cournot game with the role of buyers replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.
- A gas producer in MMAGas is generally a joint venture controlling major resources, such as the Cooper Basin JV (Santos, Beach and Origin Energy). Some resources

effectively controlled by a JV but not part of it are added to the JV's resources, such as the Kipper field in Gippsland, part owned by Santos, which is outside the BHPB-Exxon JV. Others however are not, for example the part of the Fairview field not owned by GLNG is not considered as part of the GLNG JV's reserves.

Gas producers, i.e. the JVs, are assumed to make joint sales and to compete fully with one another, even when the JVs have some common ownership. This may overstate the level of competition, however in practice this is offset by additional competition created by separate selling within some JVs.

MMAGas outputs have been benchmarked against gas production and transmission flows reported by AEMO on the "Bulletin Board" and against new GSA prices wherever such information becomes available. Model parameters for the current implementation have been estimated so that its outputs replicate negotiated GSA price and volume outcomes over the past seven years. It is noted that historical GSA prices have covered a narrow range relative to potential future prices and MMA recognises that, as with all approaches to projection, MMAGas ability to accurately project results outside of its development data range is not guaranteed. The projections made under any specific set of assumptions should not be regarded as 100% precise, even though they are expressed as a single set of numbers.

One of the most critical assumptions in MMAGas is that negotiations for new GSAs take place well before the GSAs start, to enable new capacity to supply GSAs to be constructed. This is consistent with market behaviour to date, ensures that all uncontracted reserves can be considered for new GSAs and thereby leads to the lowest prices consistent with the concentration of reserve ownership. However, reserves being developed to meet anticipated LNG GSAs have been withheld from the domestic market[18] and we have therefore added a reserve withholding mechanism to MMAGas to replicate this. A GSA entered in March 2010 by BG Group and BOC for 30 PJ over 15 years from 2011 suggests that withholding may no longer be applicable, though the volume in this GSA in low and would barely change BG Group's reserves available for LNG.

The current implementation of MMAGas represents the eastern states market as up to twenty separate producers competing in nine separate domestic market zones plus one LNG export zone. Further details on MMAGas are provided in Appendix A.

6.2.1 Recent updates

Since the Queensland LNG Industry Viability and Economic Impact Study undertaken for Queensland DIP in 2009, which is the most recent MMA report based on MMAGas that is in the public domain[19], the LNG related inputs and interactions with the domestic sector have been substantially revised.

[18] For example, as reported by Rio Tinto in its submission to the Commonwealth Government's Energy White Paper. http://www.ret.gov.au/energy/Documents/ewp/pdf/EWP%200102%20DP%20Submission%20-%20Rio%20Tinto.pdf

[19] Available at http://www.dip.qld.gov.au/resources/project/liquefied-natural-gas/final-mma-1-may-09.pdf

6.2.1.1 LNG demand on a project by project basis

LNG demand is now modelled on a project by project basis so that it can be associated with the relevant gas reserves. Details of projections are provided in Table 4-10, Table 4-11 and Table 4-12.

6.2.1.2 LNG assumed GSAs

Each LNG project's economics will be optimised by maximum use of the project's own gas reserves. Each project's reserves are therefore assumed to be contracted to the project, up to a level equal to the lesser of the reserves available and the reserves required to be dedicated to the project, i.e. the annual requirement x term of contracts. The contracted reserves are withheld from sale to other LNG projects or the domestic market.

In the surplus situation sufficient reserves are withheld to meet all LNG plant requirements internally and excess reserves, after allowing for a margin of safety, are available for sale to third parties, including other LNG projects. Excess reserves may also be withheld from the market to avoid giving competing LNG projects an advantage, which can be modelled by using very large safety margins. It is noted that APLNG has agreed to supply BG Group from jointly owned tenements ATP 648P and 620P both of which are operated by BG Group. The sale contemplates volumes of 190 PJ over a two year ramp-up period followed by an average of 25 PJ/yr over the following 18 years, starting in 2014. The total period volume of 640 PJ appears to represent the whole of APLNG's share of the tenements. Because of BG Group's control over development of this resource, this sale does not contradict our assumptions about withholding more generally.

In the shortfall situation all reserves are withheld and the project still needs to obtain external GSAs to fully meet LNG plant requirements. After reserves are dedicated to the project, excess reserves generated by further reserves growth, if any, are available for sale to third parties.

6.2.1.3 Timing of contract negotiations

Prior to the emergence of LNG export proposals the exact timing of contract finalisation was relatively unimportant to the outcomes projected using MMAGas. However it is now critical to the availability of reserves for LNG project FID and consequently for the domestic market. Finalisation for supply in 2014 is assumed to take place during 2010, for 2015 in 2011 etc, and in MMAGas this is achieved by bringing the LNG dedication requirement forwards by 4 years and bringing domestic demand for new contracts forwards by 4 years.

6.2.1.4 LNG GSA demand function

In negotiating "external" GSAs with LNG project proponents, gas producers will want to share in the LNG netback value at Gladstone, or at the gas field, depending on the point of sale. The netback value is the delivered price of LNG less the costs of liquefaction and shipping.

The delivered price of LNG depends primarily on the price of crude oil (using the Japan Crude Cocktail or JCC measure) and the $US/$A conversion rate, and secondarily on the link between LNG prices in $US/mmbtu and the JCC price in $US/bbl. For this study we have used a direct linkage without a cap or floor, namely LNG Price = 0.15 * JCC price. Thus at $US80/bbl oil, the LNG price is $US12/mmbtu

MMA has previously estimated the costs of liquefaction and shipping for Gladstone LNG in the course of work for the Queensland Government on the economics of the LNG sector as a whole. Netback values for a range of oil prices and conversion rates are shown in Table 6-1. The values vary considerably and at low JCC prices and high $US/$A values, the netback falls below the likely cost of gas supply at Gladstone.

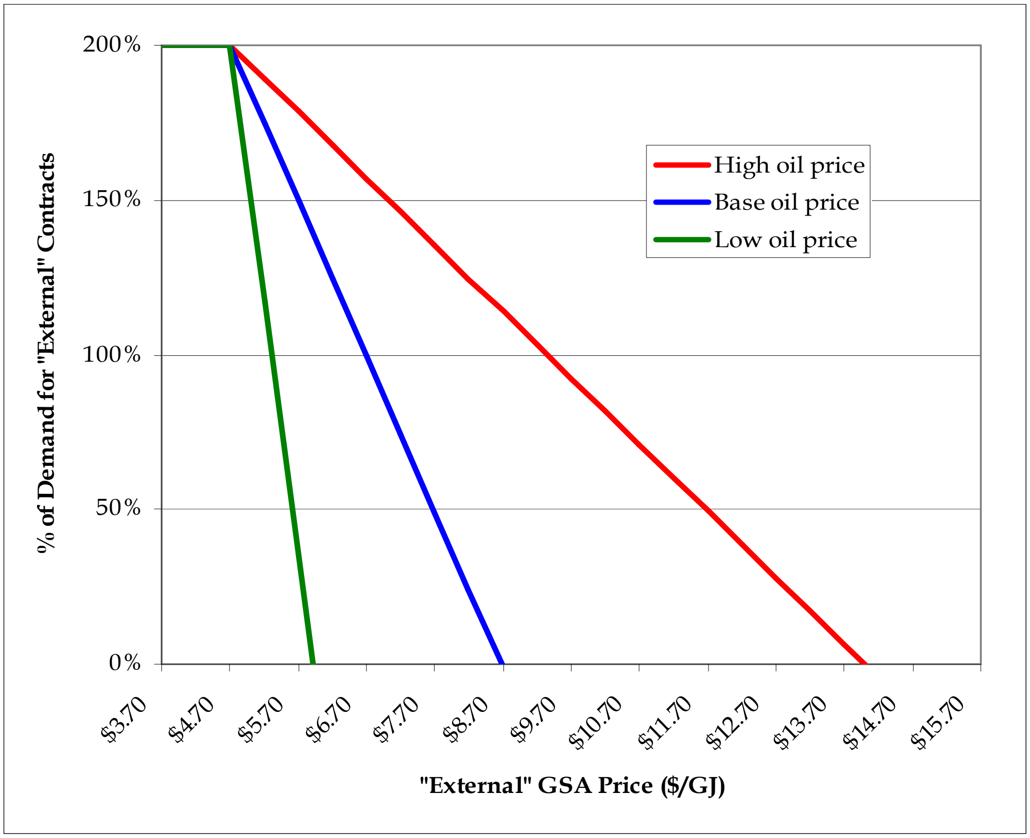
It is assumed that an "external" GSA purchaser will not be prepared to pay more than the netback value at Gladstone for gas delivered to Gladstone, because a higher price would render the LNG project uneconomic, i.e. effectively demand for "external" GSAs is zero at delivered prices above netback. It is also assumed that GSA 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 $4.70/GJ is assumed in all modelling. The netback margin for LNG or pure profit on LNG, is the difference between the netback value and the production plus transmission cost.

Table 6-1 LNG Netback values at Gladstone for various Oil Prices and $US/$A Values ($A/GJ, $2008 values)

	JCC price ($US/bbl)				
$US/$A	**$60**	**$70**	**$80**	**$90**	**$100**
$0.60	$6.95	$9.32	$11.69	$14.06	$16.43
$0.70	$5.91	$7.94	$9.97	$12.00	$14.03
$0.80	$5.13	$6.90	$8.68	$10.46	$12.24
$0.90	$4.52	$6.10	$7.68	$9.26	$10.84
$1.00	$4.03	$5.45	$6.87	$8.30	$9.72

These values are taken into consideration in structuring the linear LNG "external" GSA demand function used in the Nash-Cournot model depicted in Figure 6-2.

Figure 6-2 "External" LNG GSA Demand Functions



Refer to text for explanation

6.3 Assumptions

Key assumptions in regard to the demand-supply balance and future prices of gas in Eastern Australia are:

- The number of competing gas producers and the gas resources available to them
- Individual producers' gas production costs and production cost escalation
- The costs of transmission faced by the buyers from different producers.

6.3.1.1 Competing gas producers

The number of producers competing in the Eastern Australian gas market is currently the 20 joint ventures represented in Table 5-5. The assumption that these joint ventures are the competitive entities in the market is a reasonable approximation of reality – in some cases competition between JVs may be restricted by participation of some companies in both JVs but this may be offset by competitive marketing within JVs. It is noted that transmission costs present a barrier to producers competing in all nine zonal markets.

The current uncontracted reserves of the producers are shown in Table 5-5 and their projected future reserve additions are discussed in section 5.4. Changes in these quantities over time, as further gas is contracted and reserve additions are made, are projected using MMAGas. MMAGas can also accommodate changes in industry structure such as gas reserve additions in new provinces, market entry by new producers and reductions in the number of producers due to mergers or takeovers. However these changes are not calculated within the model but must be input as data – our base case assumption is that the number of producers remains static and only their resources and costs change.

6.3.1.2 Gas production costs

Gas production cost escalation relative to levels three to four years ago in Eastern Australia is assumed to start at 30% and then decline by 1% p.a. due to technology improvement and innovation.

6.4 Gas supply projections

6.4.1 Domestic plus LNG

The projected aggregate gas supply patterns for Eastern Australia, including LNG export requirements, for the High, Medium and Low scenario demand projections presented in section 4, are depicted in Figure 6-3, Figure 6-4 and Figure 6-5.

Key aspects are:

- Overall dominance of Queensland CSG production, which supplies the most of the LNG exports
- Strong growth in NSW CSG, mainly from the Gunnedah basin and particularly in the High Scenario
- A resurgence in production from the Cooper Basin, based on conversion of recently reported 2C resources to 2P, particularly in the High Scenario which results in higher prices (refer to section 0)
- Modest growth in Gippsland Basin production
- Declining production in the Otways and Bass Basin owing to declining reserves

Figure 6-3 Projected gas supply, Eastern Australia domestic plus exports, High scenario (PJ)

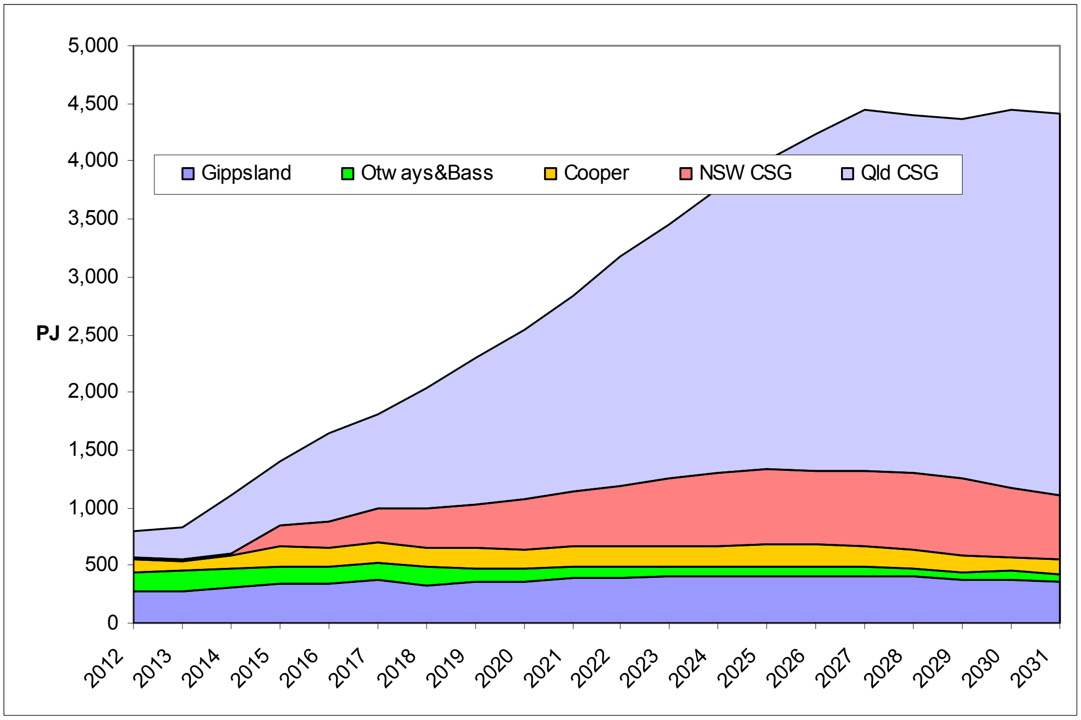


Figure 6-4 Projected gas supply, Eastern Australia domestic plus exports, Medium scenario (PJ)

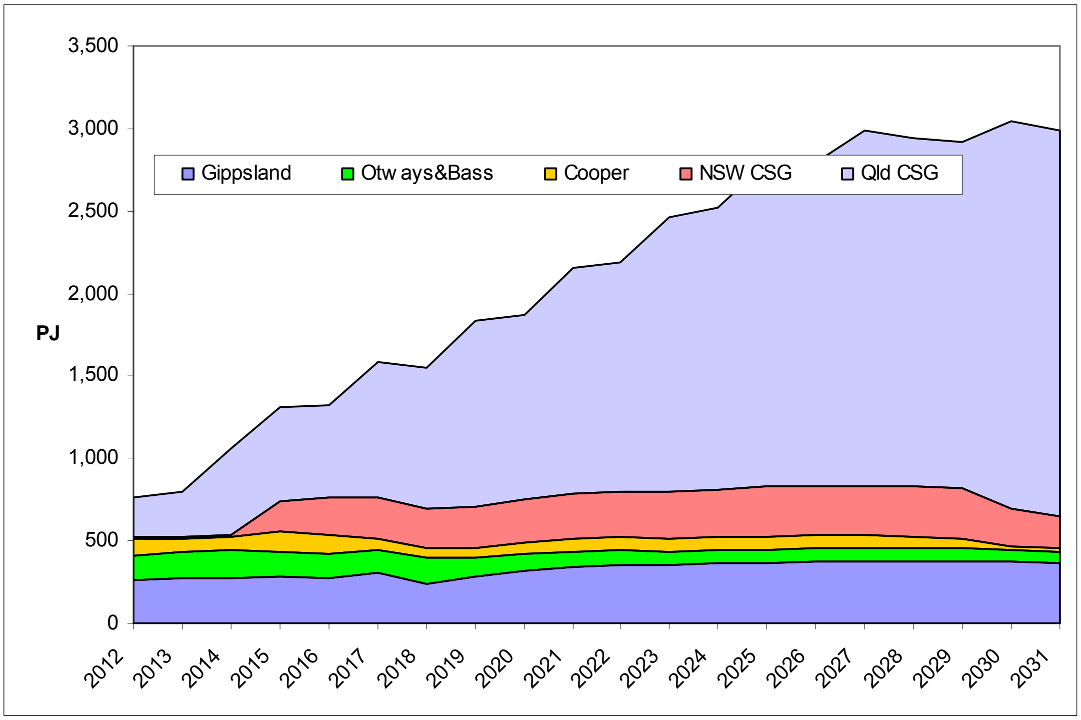
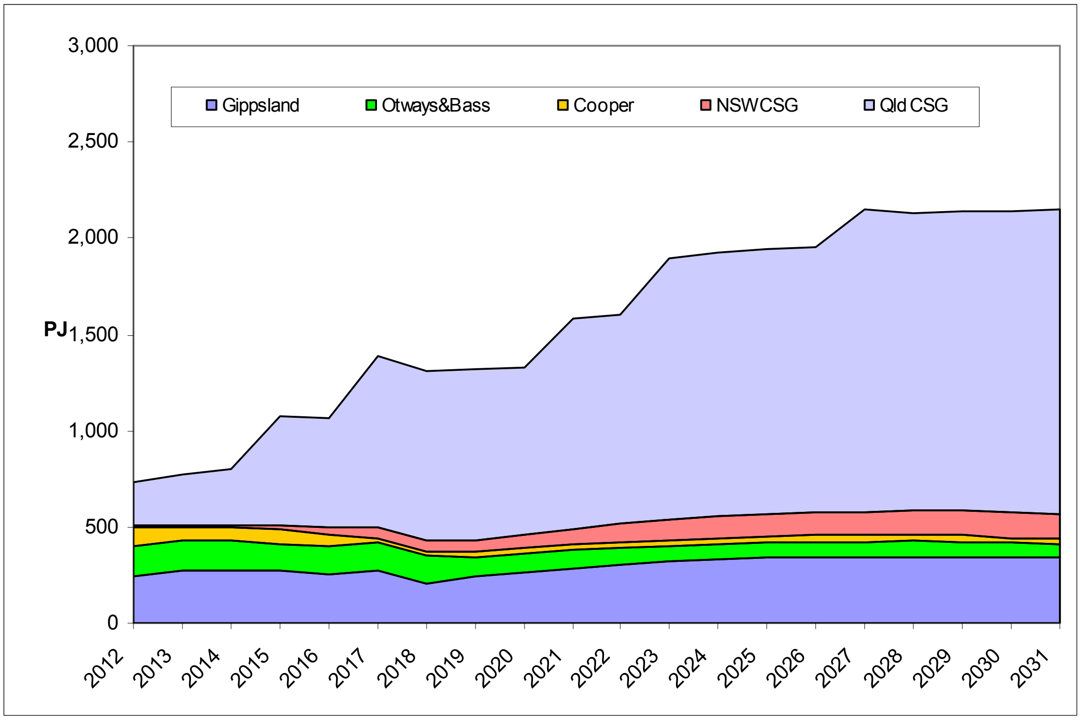


Figure 6-5 Projected gas supply, Eastern Australia domestic plus exports, Low scenario (PJ)



6.4.2 Domestic, Eastern Australia

The projected aggregate gas supply patterns for Eastern Australia, domestic only, for the High, Medium and Low scenario demand projections presented in section 4, are depicted in Figure 6-6, Figure 6-7 and Figure 6-8.

Key aspects are:

- Aggregate declines after 2025 related to GPG projections
- Relatively modest growth in Queensland CSG relative to reserves owing to dedication of reserves to exports, particularly in the High scenario
- Rapid growth in NSW CSG production from about 2015, from the Gunnedah, Gloucester and Clarence Moreton Basins
- Resurgence in Cooper Basin production, particularly in the High scenario
- Long term increases in Gippsland production due to producers outside the dominant Exxon-BHPB JV. These increases are substituting for Otway and Bass Basin production supplied to Victoria and South Australia.

Figure 6-6 Projected gas supply, Eastern Australia domestic only, High scenario (PJ)

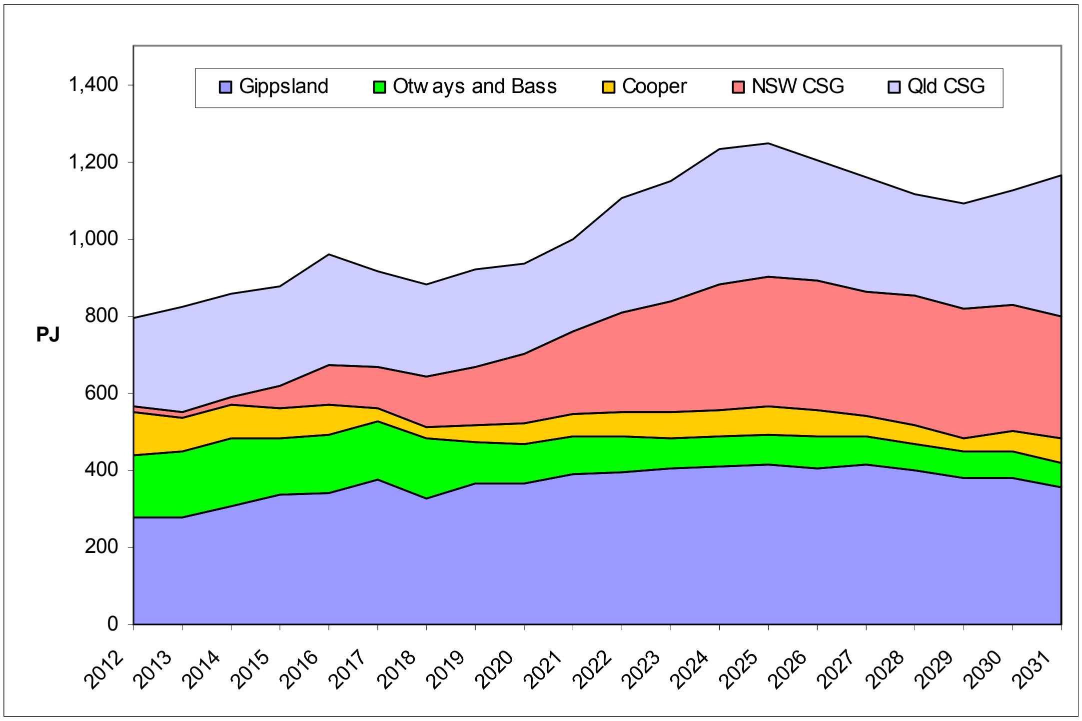


Figure 6-7 Projected gas supply, Eastern Australia domestic only, Medium scenario (PJ)

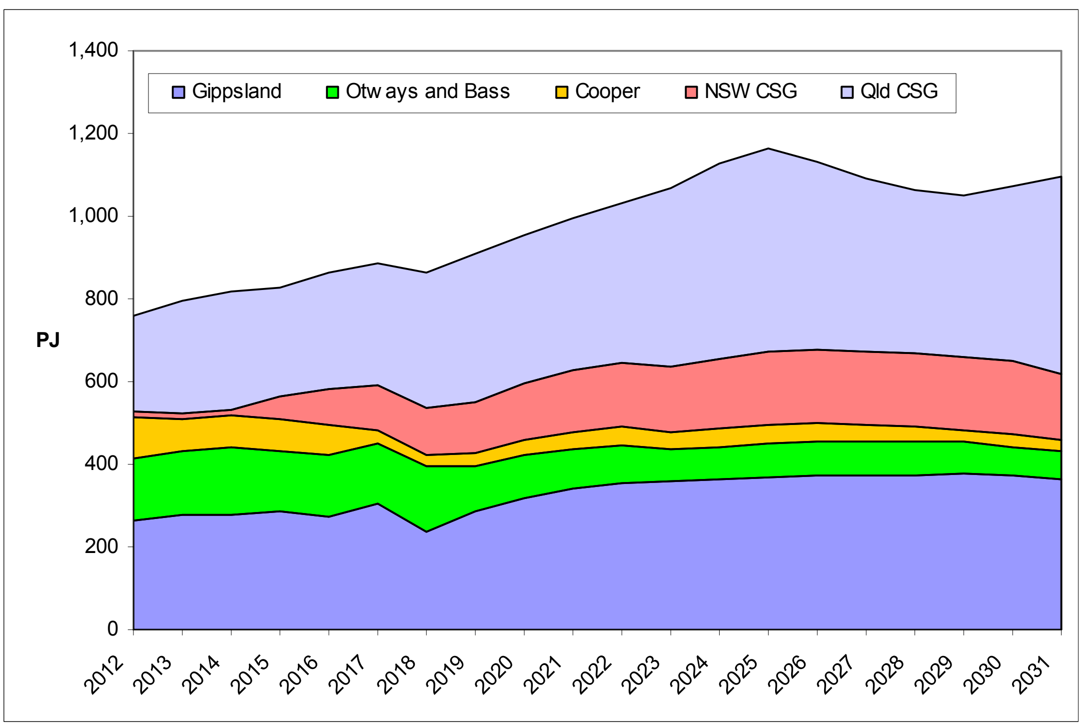
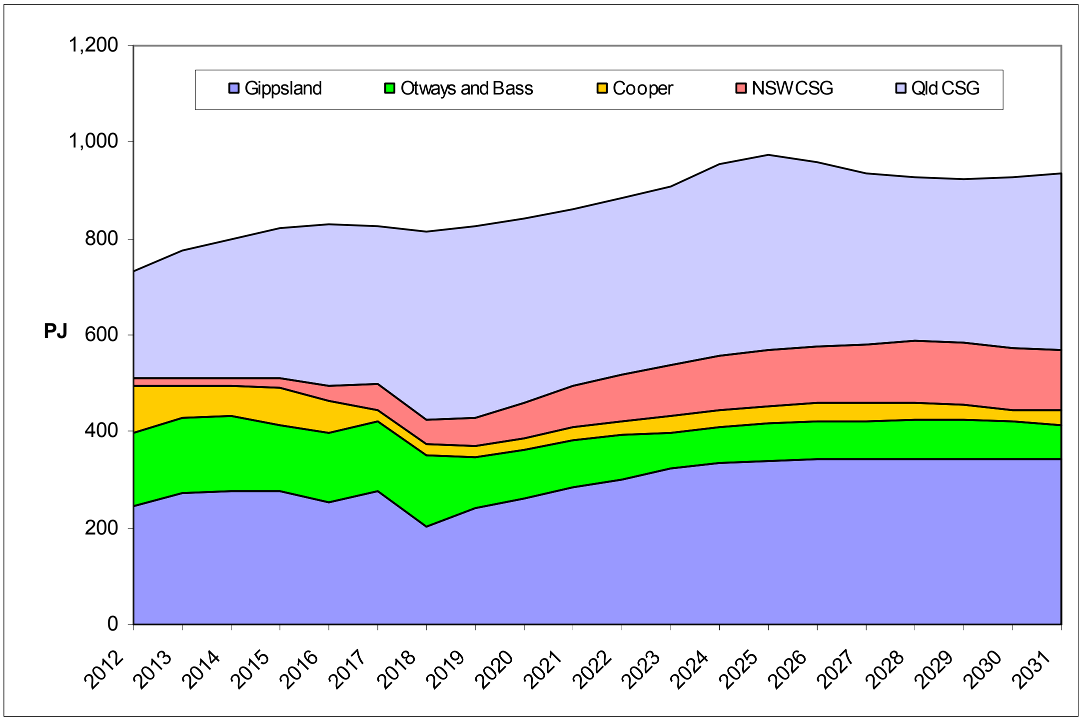


Figure 6-8 Projected gas supply, Eastern Australia domestic only, Low scenario (PJ)



6.4.3 Domestic Queensland

The projected aggregate gas supply patterns for Queensland domestic only, for the High, Medium and Low scenario demand projections presented in section 4, are depicted in Figure 6-9, Figure 6-10 and Figure 6-11.

Key aspects are:

- Aggregate declines after 2025 related to GPG projections
- Considerable variation between scenarios.
- In the High scenario:
    - The Queensland CSG contribution declines initially and then grows
    - NSW CSG grows substantially
    - Cooper remains steady
    - Gippsland gas enters the Mt Isa market
- In the Medium scenario there is more Queensland CSG and less of everything else, with no Gippsland gas
- In the Low scenario Queensland CSG dominates supply

Figure 6-9 Projected gas supply, Queensland domestic only, High scenario (PJ)

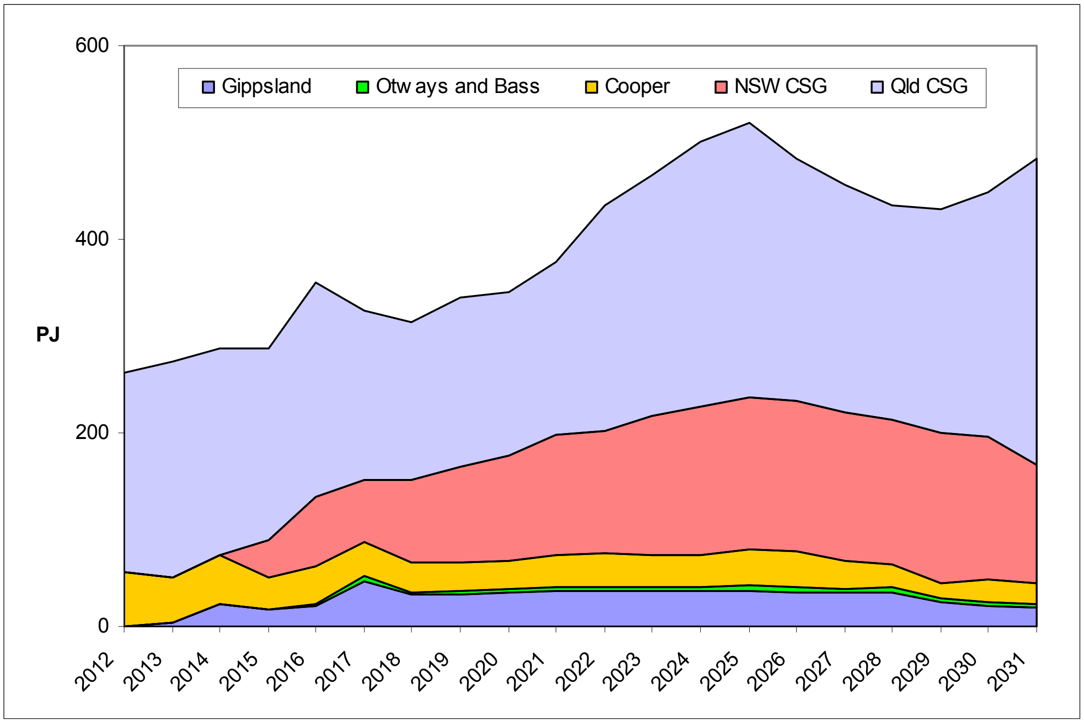


Figure 6-10 Projected gas supply, Queensland domestic only, Medium scenario (PJ)

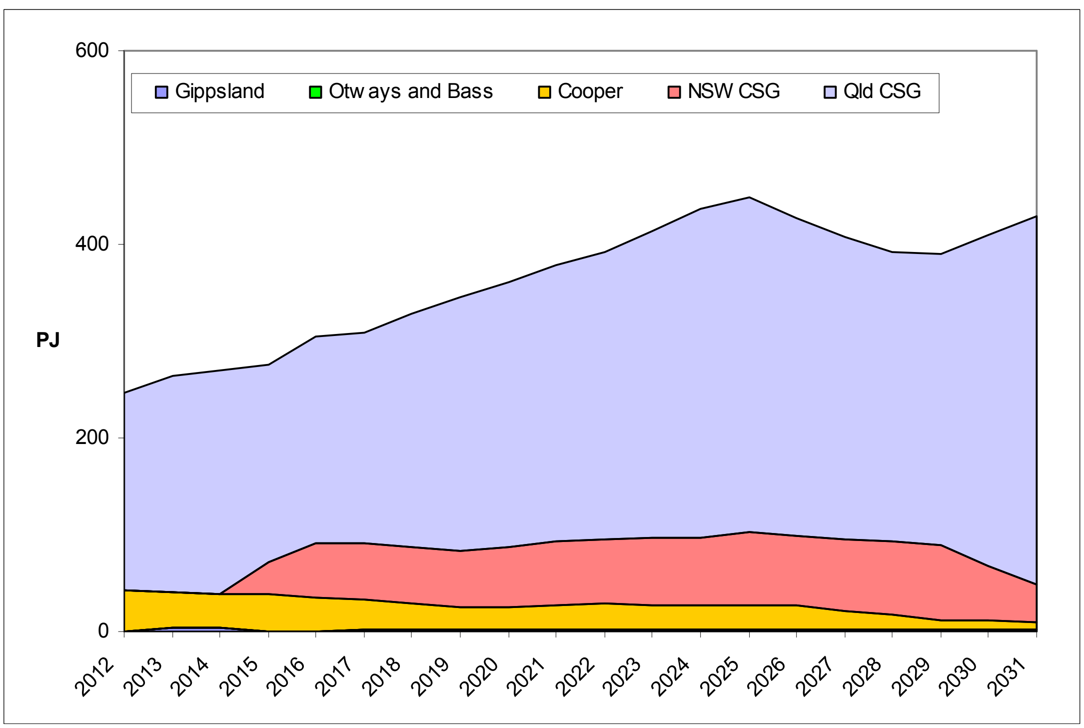
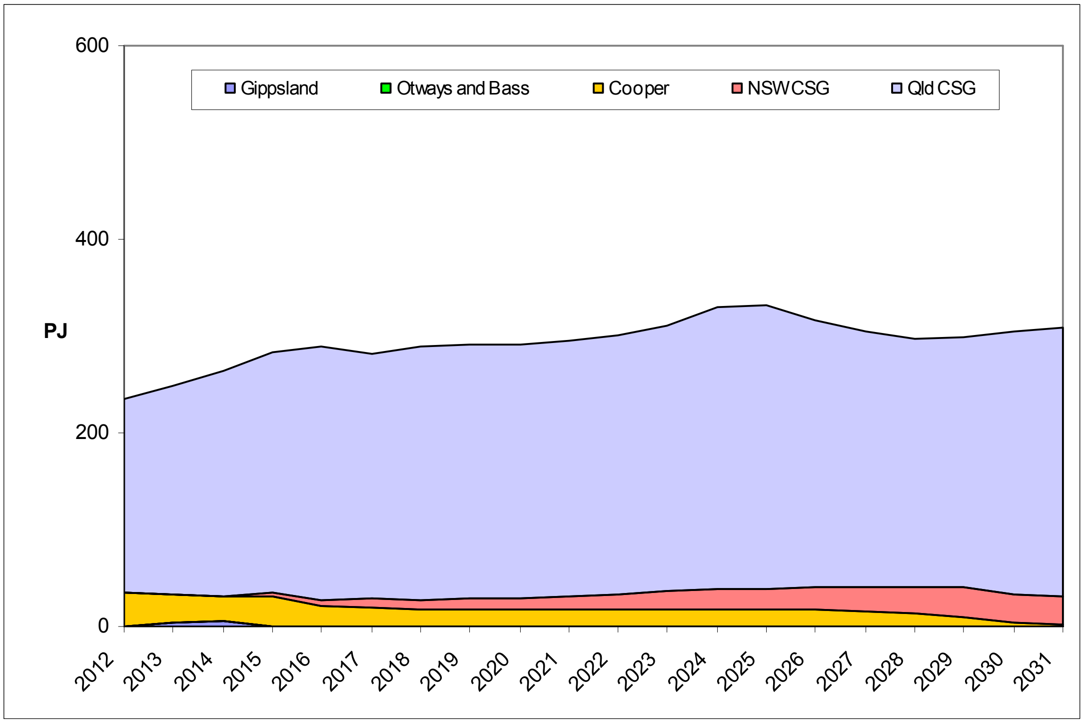


Figure 6-11 Projected gas supply, Queensland domestic only, Low scenario (PJ)



6.5 Gas price projections

Gas price projections for all three scenarios are presented in Figure 6-12 to Figure 6-25. All prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real $2010 terms. Two prices are presented for the Southern States in aggregate, Queensland in aggregate and for each market zone in Queensland:

- The estimated price of new 15-year gas contracts starting in a particular year (Figure 6-12 to Figure 6-18). It is noted that underlying assumptions include negotiation four years in advance, so that the price for 2014 is negotiated in 2010.
- The estimated average price over all gas contracts delivering gas in any year (Figure 6-19 to Figure 6-25)

The prices do not take into account the possible availability of lower priced "Ramp-Up Gas" in the period 2011-2013.

New contract prices in Southern States are projected to be relatively insensitive to the scale of LNG exports, largely due to the anticipated availability of NSW CSG from the Gunnedah and Gloucester Basins.

In contrast Queensland aggregate prices and prices in all Queensland zones apart from Mt Isa are projected to be very sensitive to the scenarios and broadly correlated with one another. Across Queensland in aggregate:

- In the High scenario (with both high domestic demand and high exports) new contract prices are expected to rise substantially from 2013, to over $7/GJ, and then to fall slightly, to approximately $6/GJ by 2030.
- In the Medium scenario (with medium domestic demand and medium exports) new contract prices are expected to rise initially to over $6/GJ but then ease to $5/GJ as reserves growth outpaces growth in exports.
- In the Low scenario (with low domestic demand and low exports) new contract prices are expected to barely increase, largely because the first exports are delayed until 2015 and the second train until 2017, significantly reducing the pressure on gas reserves relative to the Medium and High scenarios.

The trends in the Brisbane, Townsville, Gladstone and Kogan zones are similar though with different levels. Prices in Mt Isa are less scenario sensitive, in part because in the High scenario gas demand is projected to fall substantially due to connection of Mt Isa to the electricity transmission grid. As a result of this, in the High Scenario the Mt Isa new contract prices apply only to very small volumes of gas and are not ever reflected in average prices.

It is noted that projected prices would be lower in the High and Medium scenarios if the LNG reserve requirements were based on a less than 20 year 2P reserves commitments.

The Kogan zone prices are equivalent to well-head prices for CSG produced in the Kogan-Roma/Wallumbilla area.

Average contract prices follow the paths set by new contract prices but with considerable lags, which also vary between zones because of differences in timing in the need for new contracts.

Figure 6-12 New contract prices Southern States aggregate, all scenarios ($/GJ, $2010 real)

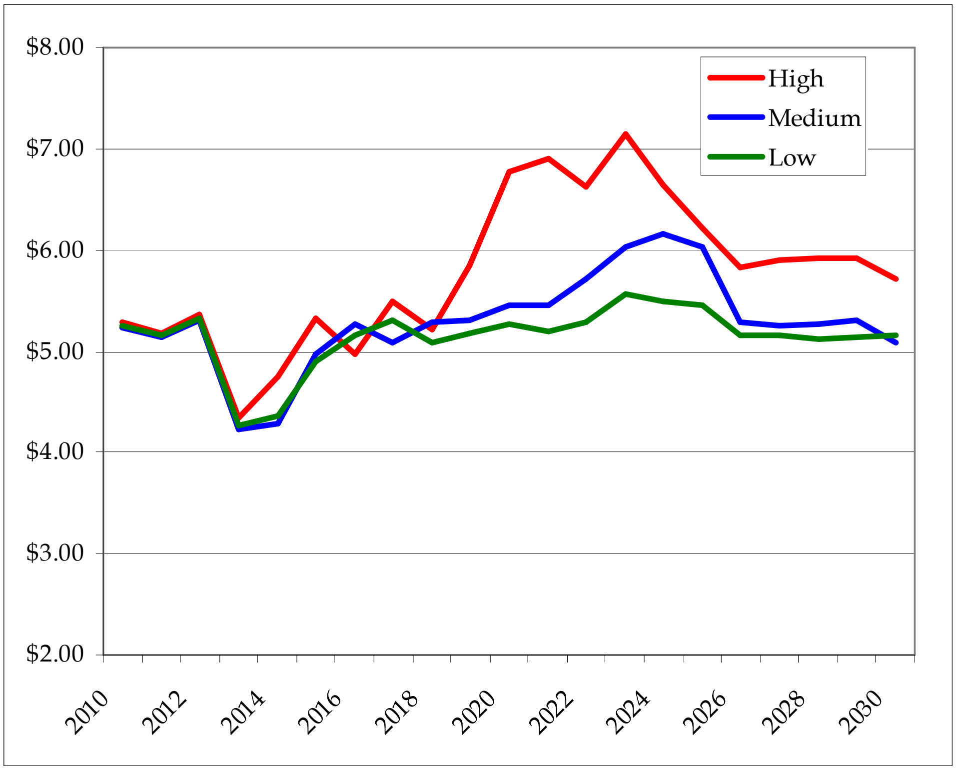


Figure 6-13 New contract prices Queensland aggregate, all scenarios ($/GJ, $2010 real)

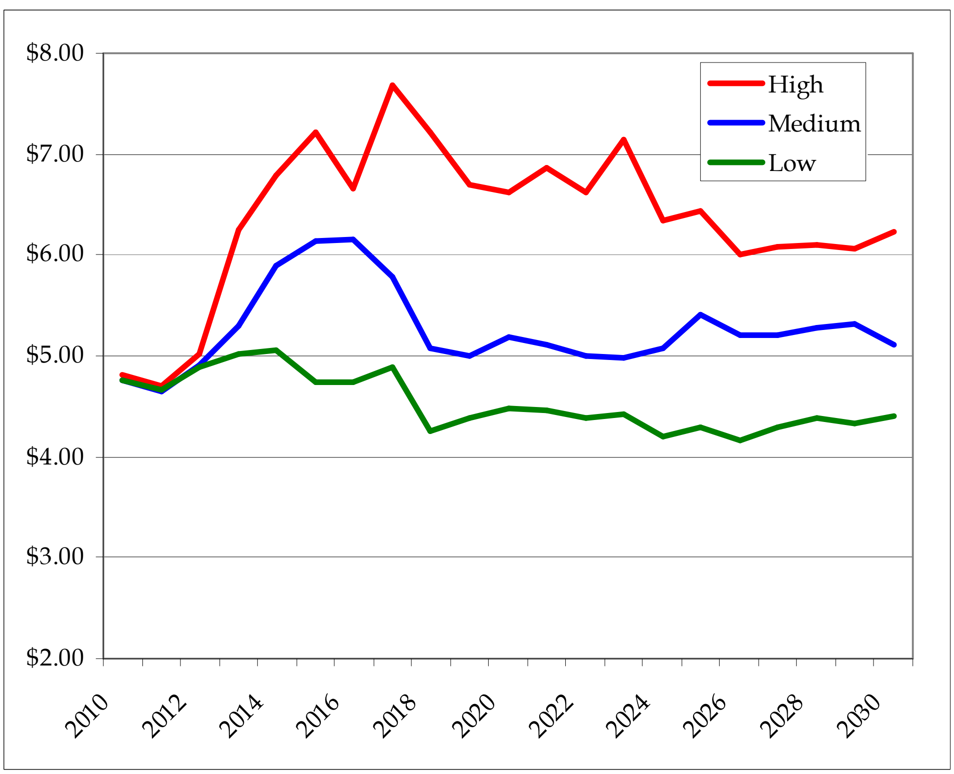


Figure 6-14 New contract prices Brisbane zone, all scenarios ($/GJ, $2010 real)

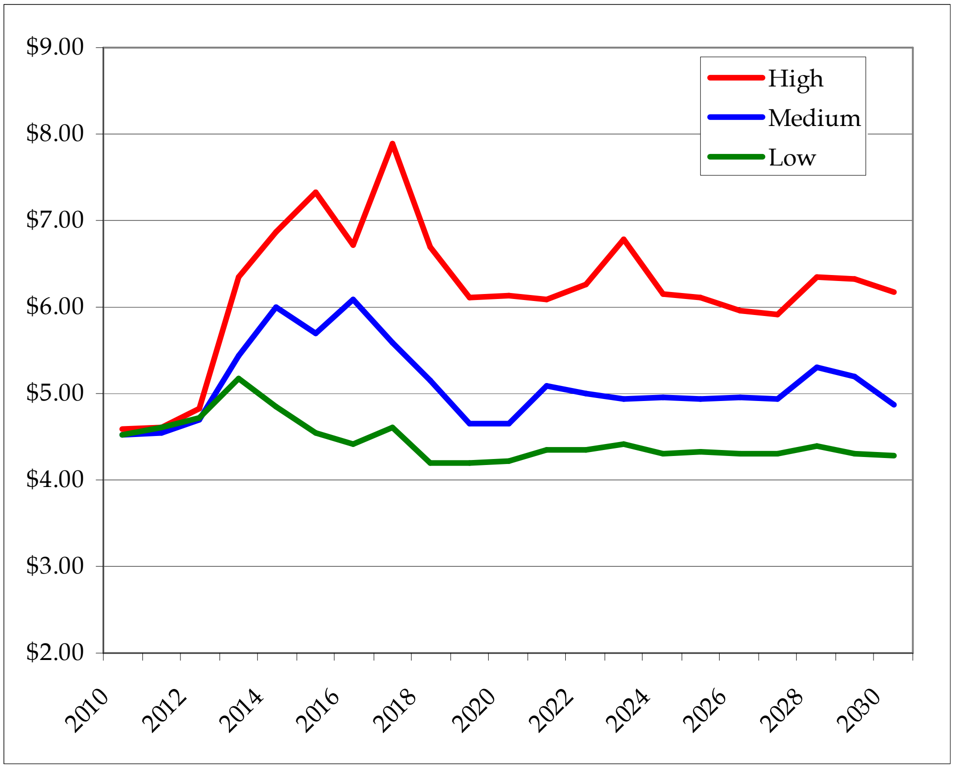


Figure 6-15 New contract prices, Townsville zone, all scenarios ($/GJ, $2010 real)

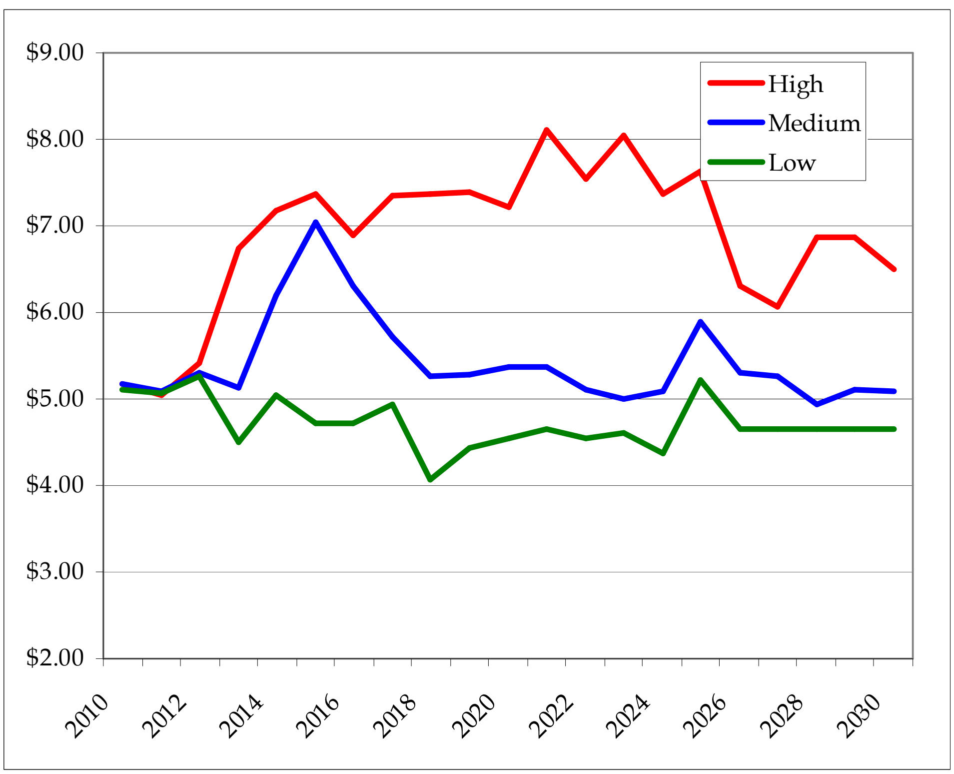


Figure 6-16 New contract prices Gladstone zone, all scenarios ($/GJ, $2010 real)

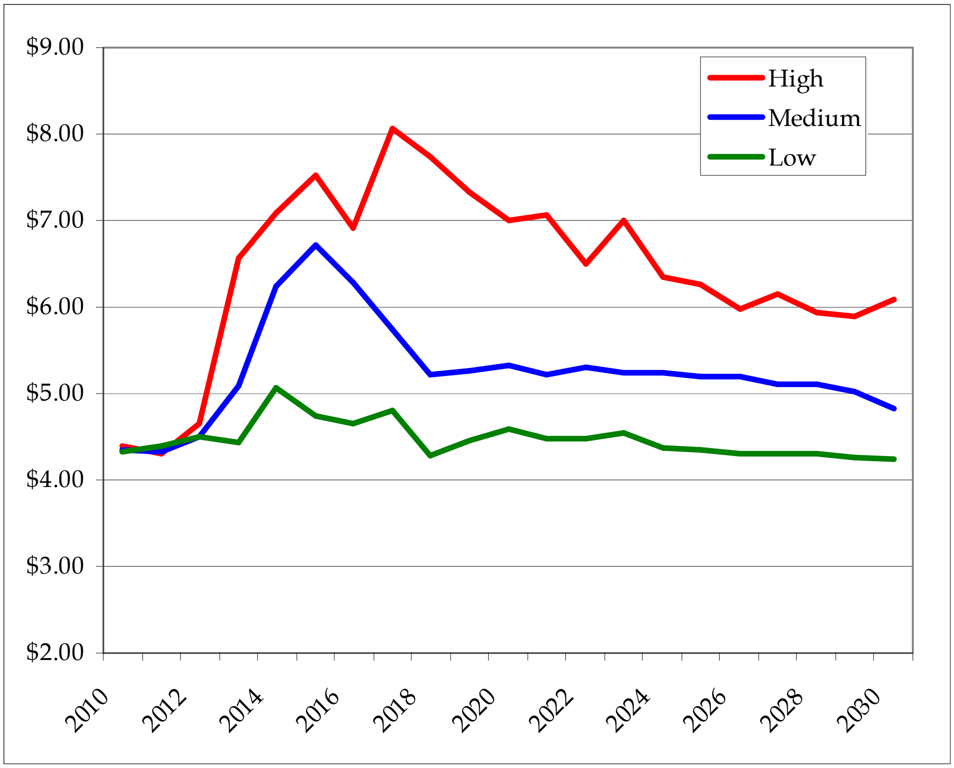


Figure 6-17 New contract prices Mt Isa zone, all scenarios ($/GJ, $2010 real)

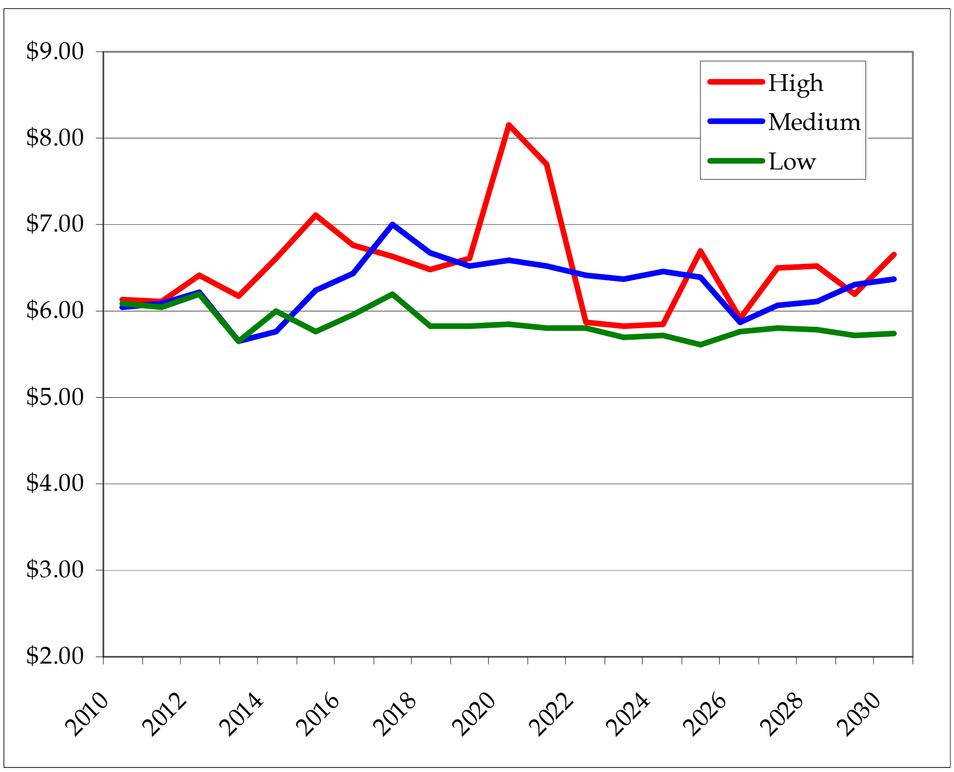


Figure 6-18 New contract prices Kogan zone, all scenarios ($/GJ, $2010 real)

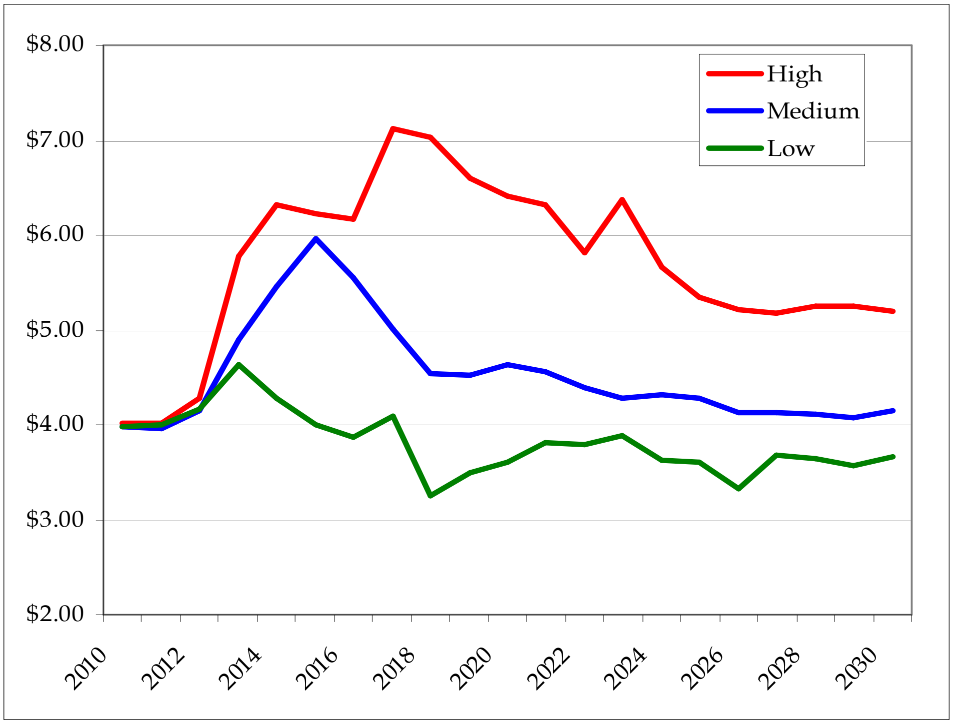


Figure 6-19 Average contract prices Southern States aggregate, all scenarios ($/GJ, $2010 real)

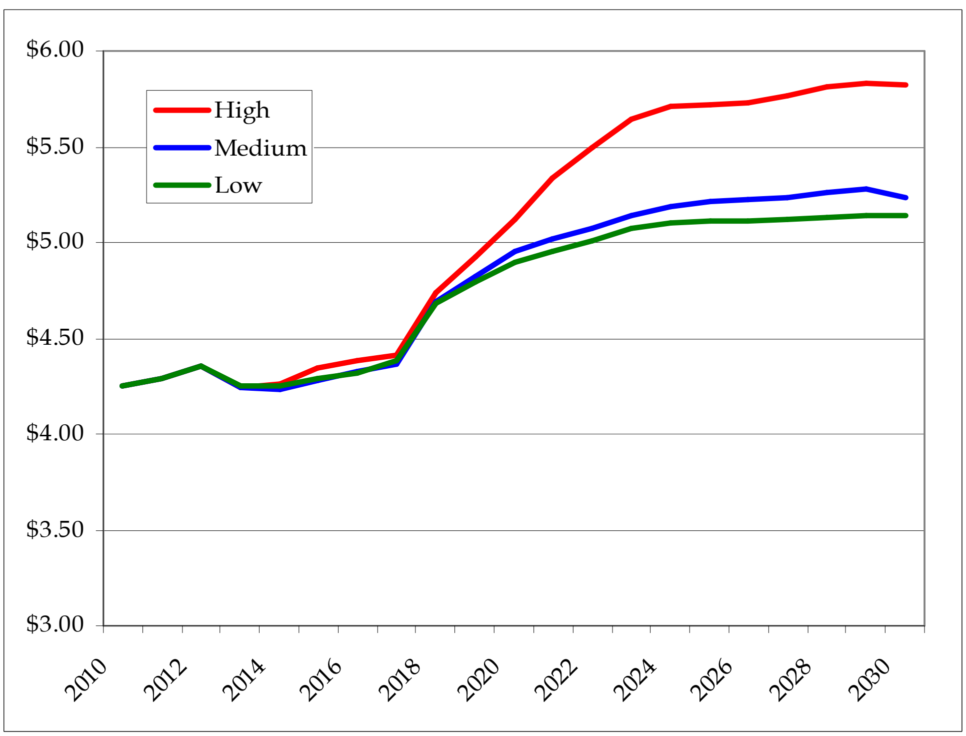


Figure 6-20 Average contract prices Queensland aggregate, all scenarios ($/GJ, $2010 real)

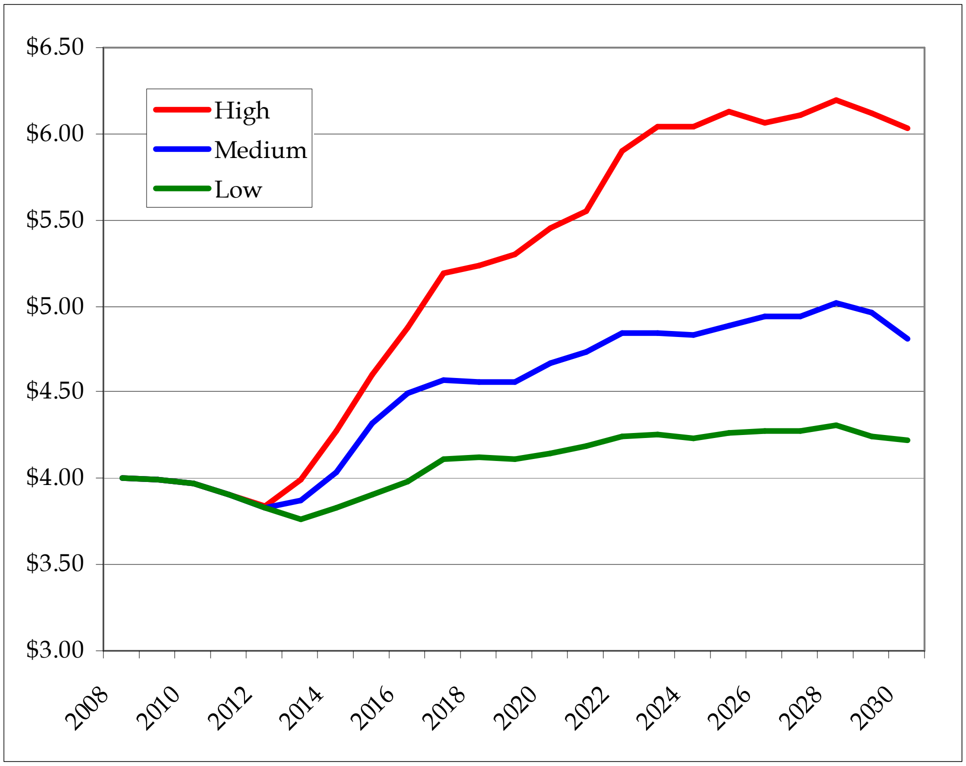


Figure 6-21 Average contract prices Brisbane zone, all scenarios ($/GJ, $2010 real)

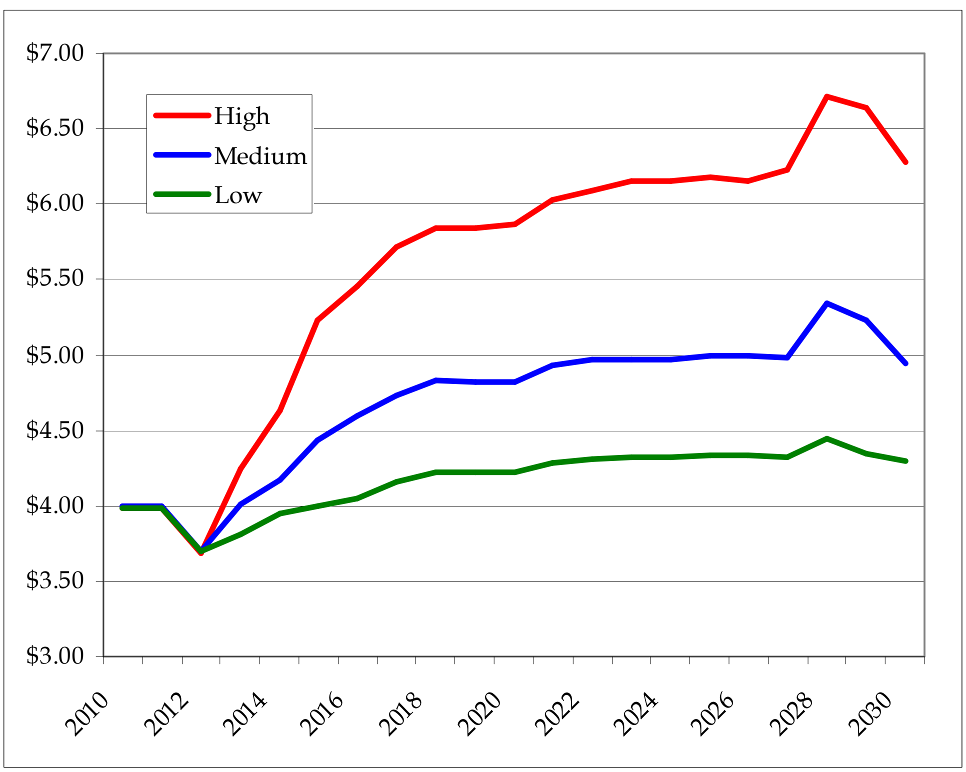


Figure 6-22 Average contract prices, Townsville, all scenarios ($/GJ, $2010 real)

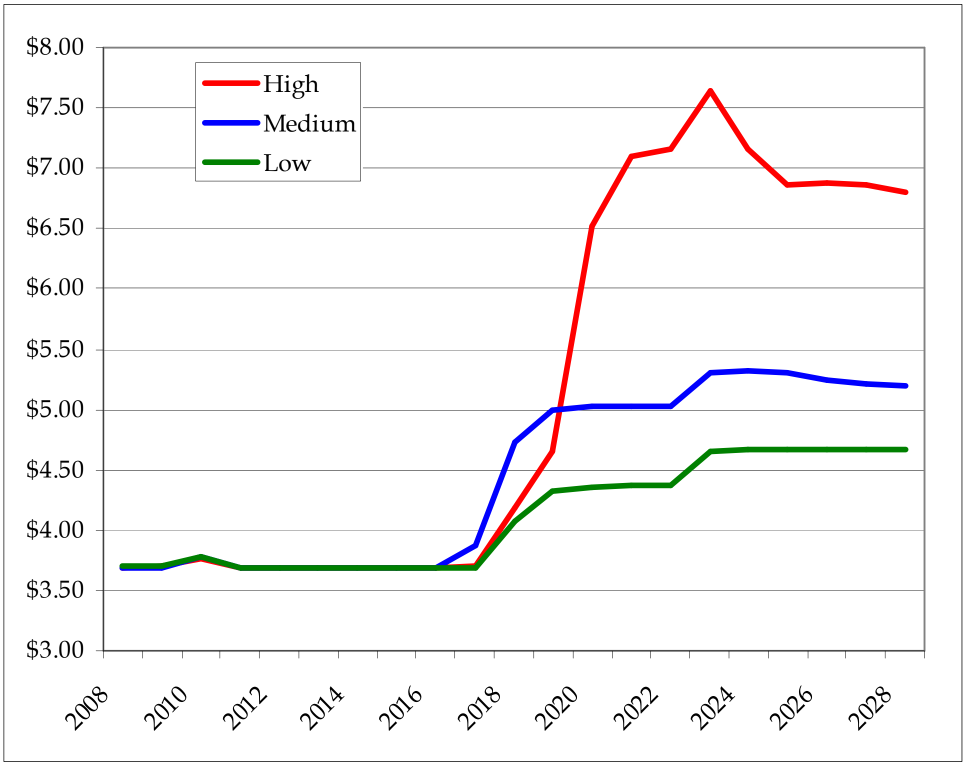


Figure 6-23 Average contract prices Gladstone zone, all scenarios ($/GJ, $2010 real)

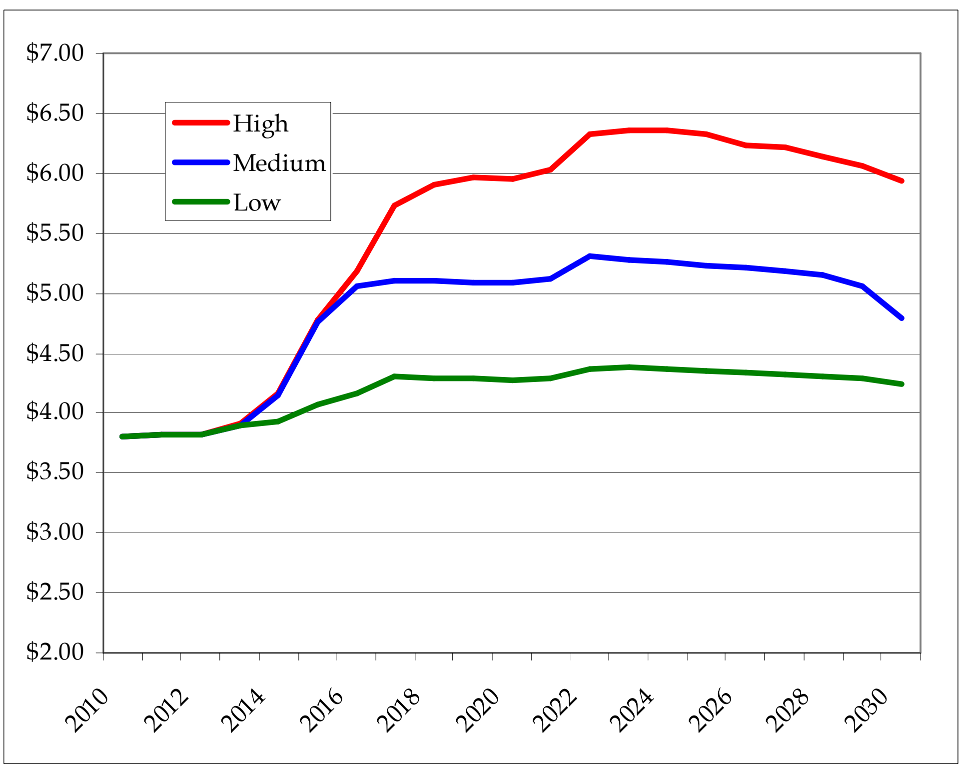


Figure 6-24 Average contract prices Mt Isa zone, all scenarios ($/GJ, $2010 real)

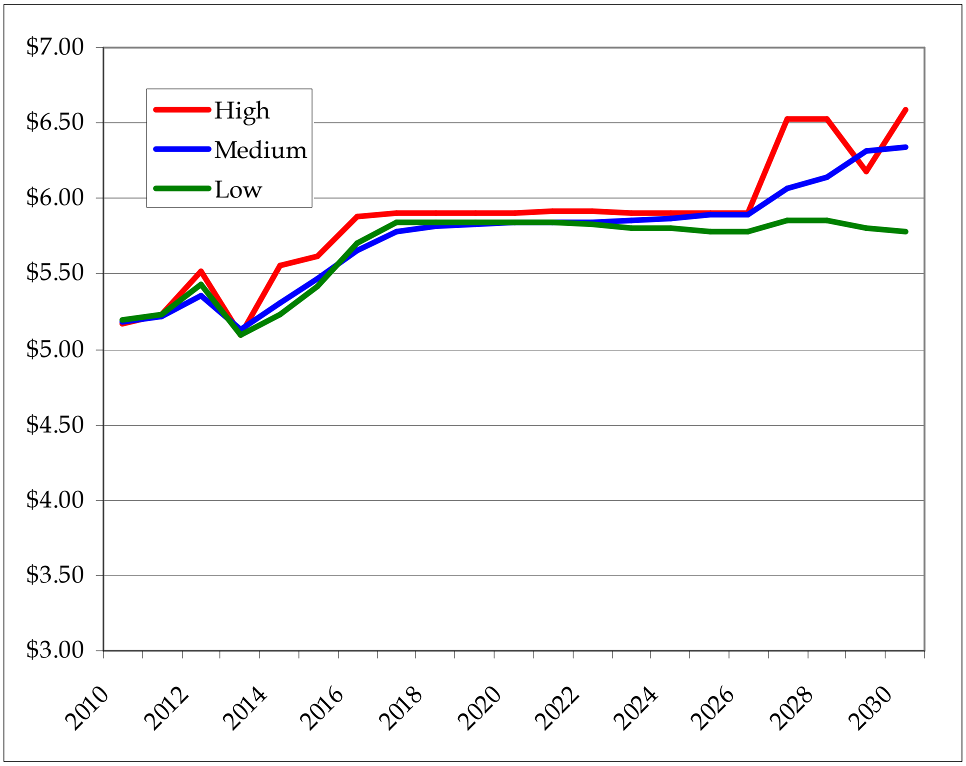
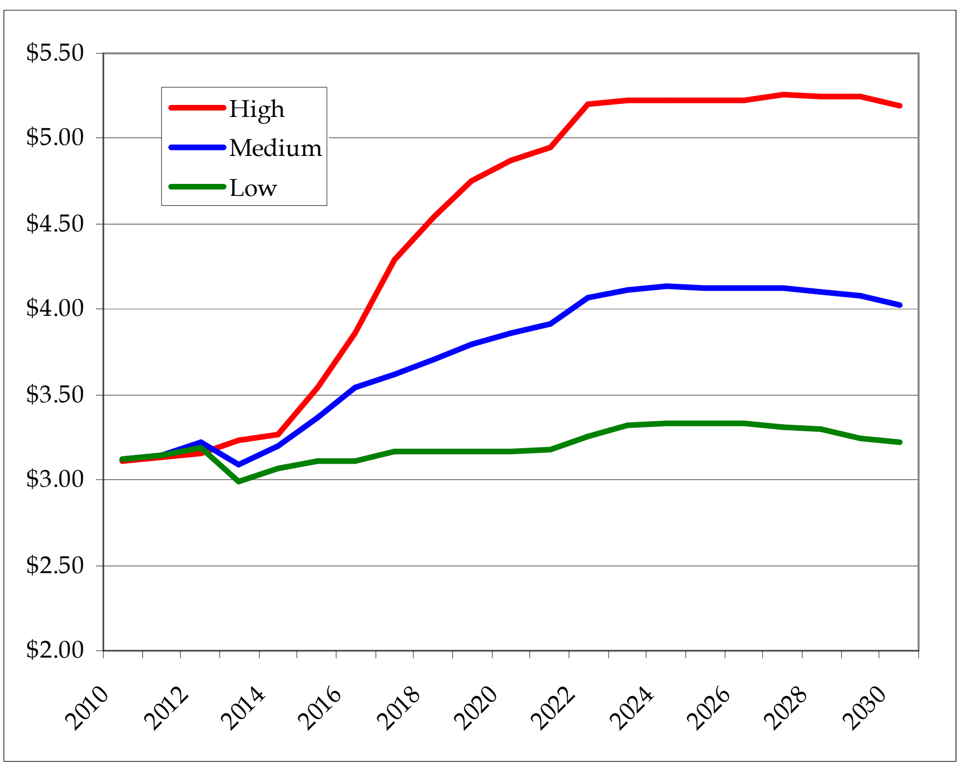


Figure 6-25 Average contract prices Kogan zone, all scenarios ($/GJ, $2010 real)

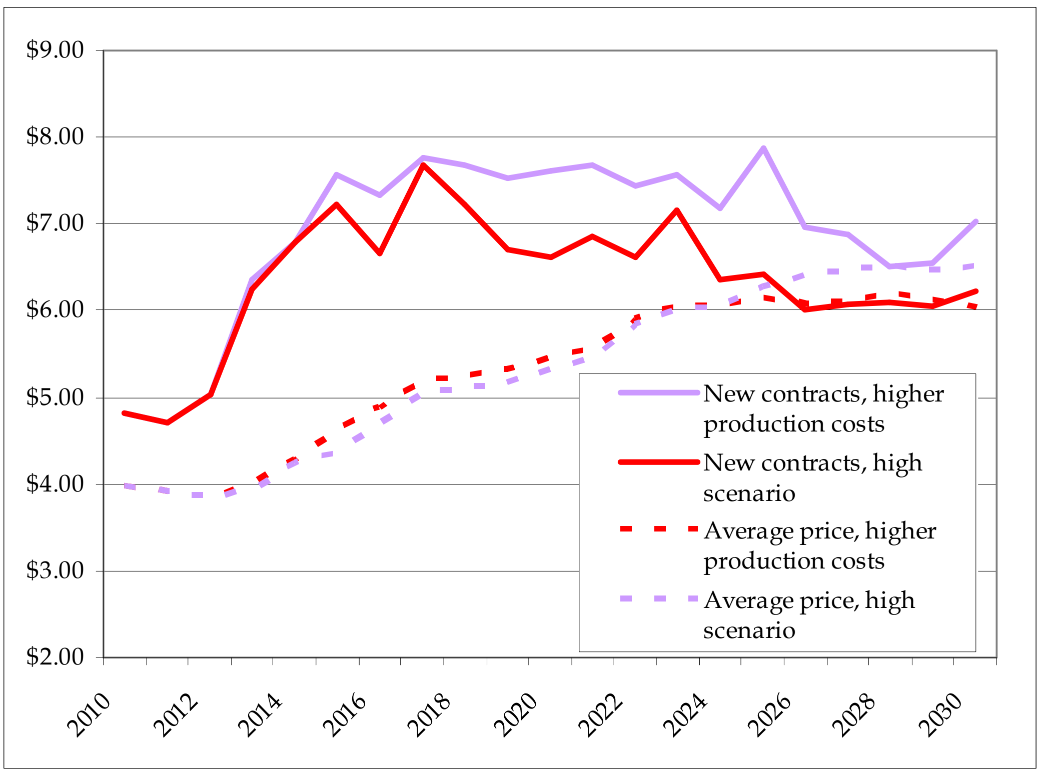


6.5.1 Higher production costs

In section 5.6 it was noted that the cost of producing future reserve additions could be higher than current costs of production. A higher cost case in which 50% of new reserve additions after 2010 can be developed at current costs and 50% can only be developed at a higher cost in the range $5-6/GJ is considered here. This case is applied only with the High scenario assumptions for other inputs.

The average increase in production costs for reserve additions is $1/GJ and this flows almost directly into new contract prices in Queensland after 2018, as shown in Figure 6-26. However there is a long lag before the impact is felt on average prices, in fact initially the average is lower owing to different weightings.

Figure 6-26 Price impact of higher production costs, Queensland average



6.6 Demand response to price increases

As noted in section 1.2 the supply projections presented in section 6.4 are always in balance with demand, that is, annual demand and supply output by the model are always equal and can never be said to be out of balance. However, the demand that is met by supply is typically not the demand that is specified as input but demand that is adjusted through the pricing mechanism. The demand response to prices measured by the difference between the input and output demand levels offers a measure of demand-supply "imbalance".

The projected price increases in the Medium and High scenarios give rise to significant reductions in demand by 2030 relative to projections based on current prices, ranging up to 34% in Queensland in the High case with higher production costs (Table 6-2).

It should be emphasised that these outcomes are strongly dependent upon the price elasticity of demand, the value of which is difficult to estimate and therefore uncertain. The price elasticity assumed for Queensland demand is -0.5 relative to city gate prices[20] and the demand reduction in the High scenario, 28%, is the result of a 56% increase in delivered prices, from $3.86/GJ to $6.03/GJ, multiplied by the price elasticity. The price elasticity is used as a market aggregate – it would be expected that price changes would have different impacts on different sub-markets, such as generation and large industrial, but sub-market price elasticity estimates are insufficiently reliable to make the distinction.

Table 6-2 Estimated demand reductions by 2030 due to price increases

	Low scenario	Medium scenario	High scenario	High scenario with higher cost
Eastern Australia	5%	8%	17%	21%
Queensland	6%	13%	28%	34%

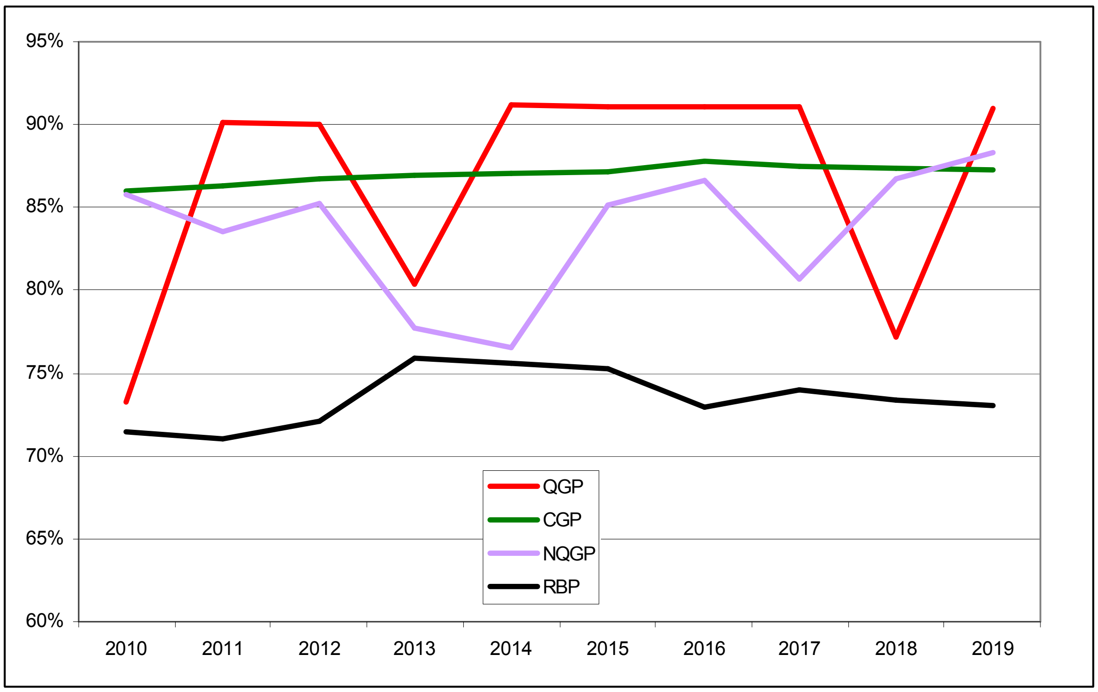
[20] The majority of gas in Queensland is consumed by large industrial and generation users at or close to city gaet prices.

6.7 Peak demand-supply

Peak demand in all Queensland sub-markets is currently met by pipeline gas, without any support from LNG or underground storage. Analysis of GSOO 2009 peak and annual demand projections suggests that each of the four major pipelines will face approximately static load factors (ratio of average daily load to peak daily load) over the next ten years (Figure 6-27). 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 ten years.

It is noted that underground storage may form part of demand-supply management for LNG projects but this is unlikely to impact on the capacity requirements for these pipelines.

Figure 6-27 Queensland gas pipeline load factors based on 1-in-2 peak demand



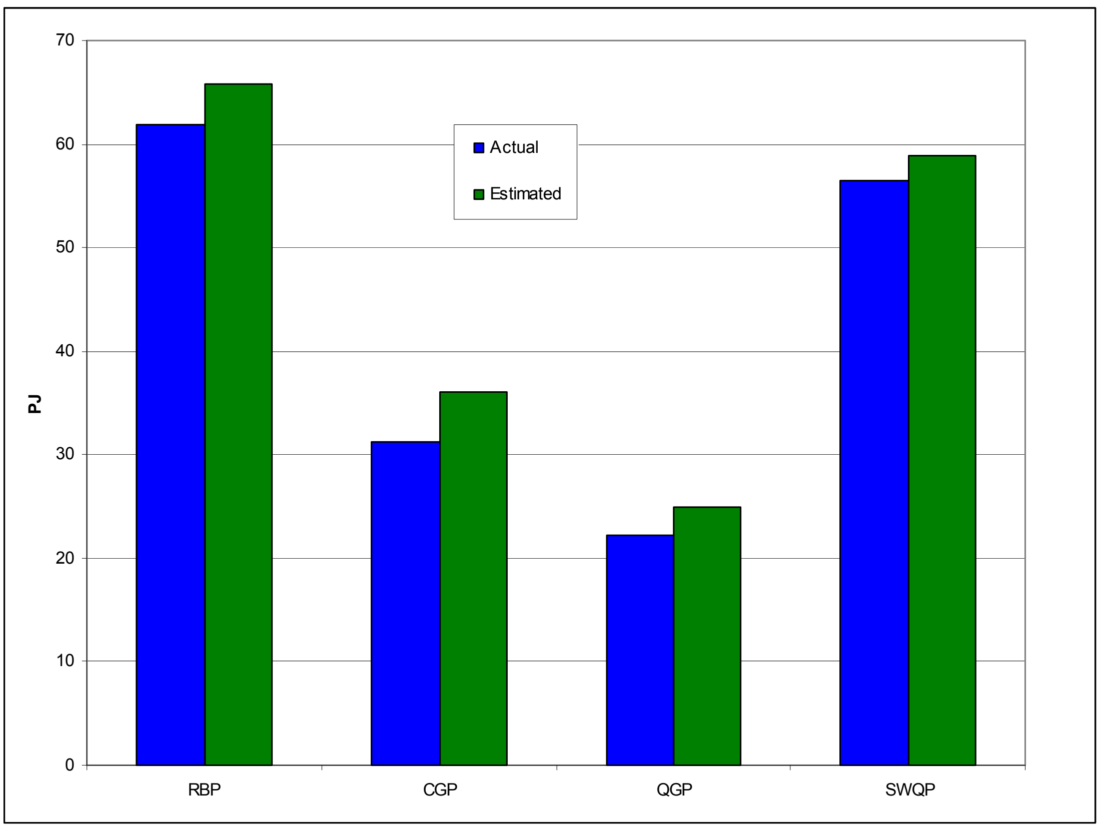
6.8 Transmission pipeline capacity requirements

Transmission capacity constraints are not explicitly modelled in MMAGas. The implicit assumption is that new transmission capacity will be added in parallel with gas production/processing capacity when required, at the costs built into the model. This assumes that the increments required are ultimately economic, i.e. annual increments add up to an economic increment over time.

Figure 6-28 shows the model output of annual throughput volume of the major pipelines under each scenario for the year 2009, as well as the actual flow quantity on those pipelines sourced from the Gas Bulletin Board.

For the purpose of addressing demand peak issues and capacity constraints, MMA estimated peak demand forecasts from annual volume throughput (forward or back haul as appropriate), which were obtained from the output of MMAGas.

Figure 6-28 Actual and estimated throughput of major pipelines (2009) – Bulletin Board & MMAGas (PJ)



6.8.1 Approach

The load factor used to estimate peak demand was calculated from a spreadsheet containing daily throughput of major transmission pipelines, which were provided by DEEDI with data sourced from the Gas Bulletin Board. In case of pipelines not yet built or those not in the Bulletin Board, MMA has assumed a load factor of 80%.

Using these load factors, the annual throughput volume (PJ) – obtained from MMAGas – was converted to an estimate of peak demand (TJ/day).

MMA has repeated this analysis by using a slightly higher load factor which may apply when pipelines approach capacity and spare capacity cannot be used on an opportunistic basis.

The peak demand estimates were then compared to the notional capacity on each pipeline to determine where capacity constraints could arise in meeting gas demand during the period.

Notional capacities of the major pipelines were provided in the same spreadsheet by DEEDI with data sourced from the Gas Bulletin Board. In case of pipelines not yet built or those not in the Bulletin Board, MMA has searched the public domain (e.g. EIS) to obtain an estimate. It is noted that notional capacities can be conservative in the sense that they may apply to firm contract capacity, which can be exceeded for short but not prolonged periods.

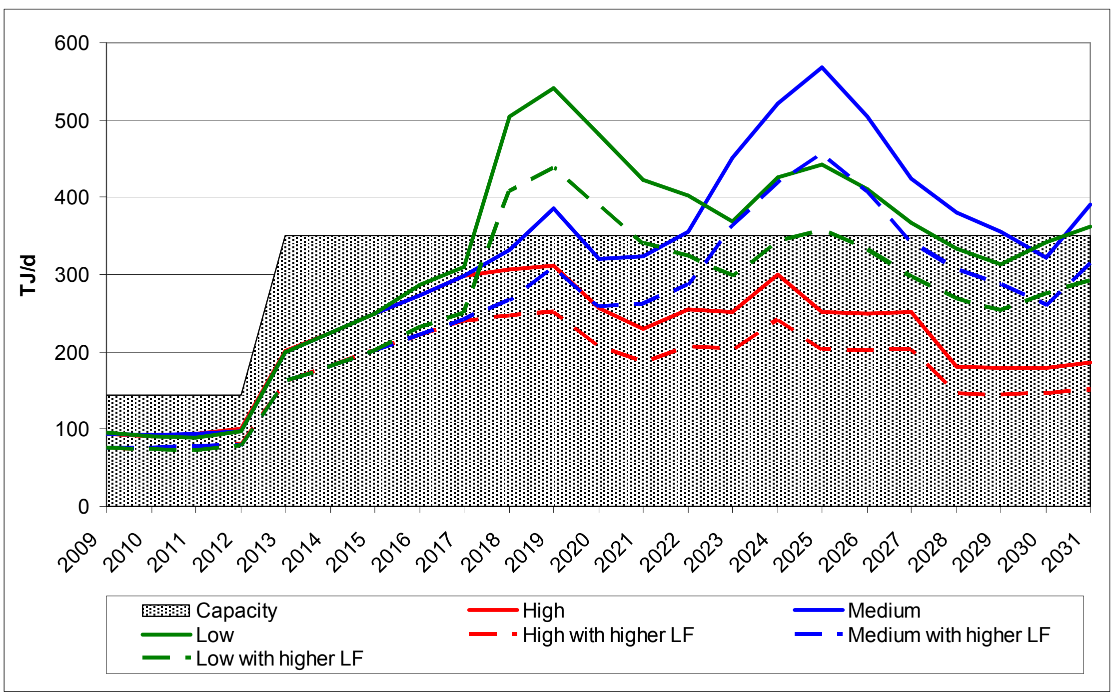
6.8.2 Projections

6.8.2.1 QSN Link

Figure 6-29 shows the projections of peak demand and capacity. The High scenario produces the lowest projections owing to the relative lack of Queensland CSG available for export to the Southern states. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, no additional capacity is required regardless of the load factor assumption used.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2022 and peaking in 2025 at roughly 200 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2023 and peaking in 2025 at roughly 100 extra TJ/d.
- In the Low scenario, additional capacity would be required at an increasing rate, starting in 2018 and peaking in 2019 at roughly 100 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2018 and peaking in 2019 at roughly 85 extra TJ/d.

Figure 6-29 Estimated peak flow and capacity - QSN Link Pipeline (QSNP) (TJ/day)

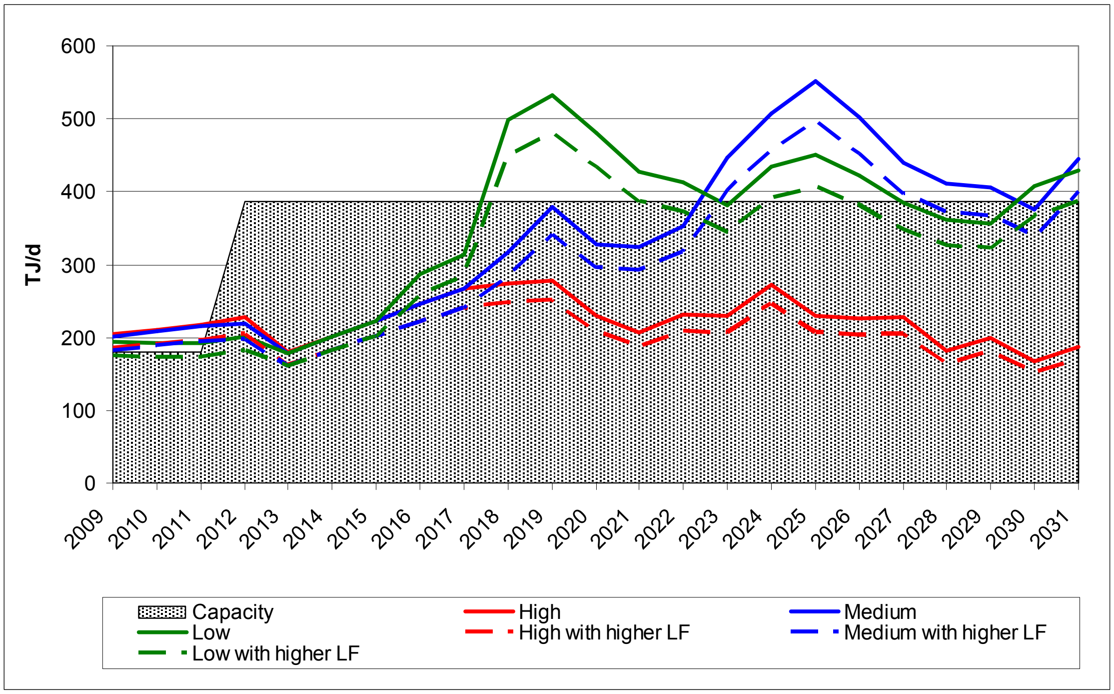


6.8.2.2 South West Queensland Pipeline (SWQP)

Figure 6-30 shows the projections of peak demand and capacity. The High scenario produces the lowest projections owing to the relative lack of Queensland CSG available for export to the Southern states. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, no additional capacity is required regardless of the load factor assumption used.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2022 and peaking in 2025 at roughly 230 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2023 and peaking in 2025 at roughly 110 extra TJ/d.
- In the Low scenario, additional capacity would be required at an increasing rate, starting in 2017 and peaking in 2019 at roughly 130 extra TJ/d. Under the higher load factor assumption, additional capacity at roughly 30 TJ/d would be required from 2019.

Figure 6-30 Estimated peak flow and capacity - South West Queensland Pipeline (SWQP) (TJ/day)



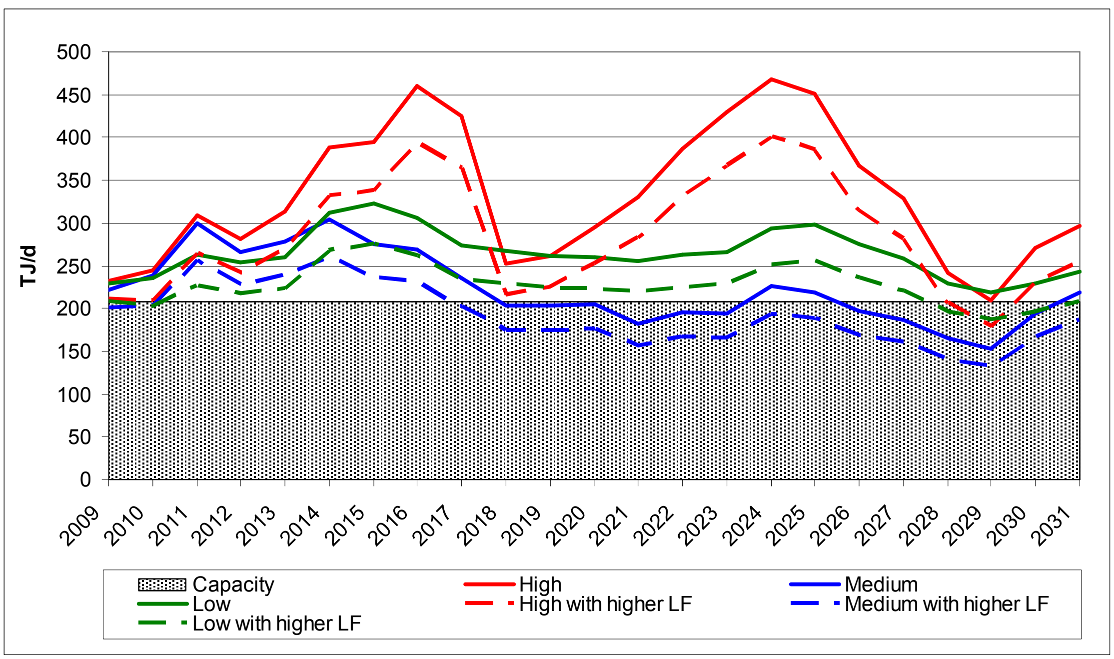
6.8.2.3 *Roma to Brisbane Pipeline (RBP)*

Figure 6-31 shows the projections of peak demand and capacity. This pipeline is already at full capacity and some future capacity requirements could be substituted by the potential Lions Way pipeline.

The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2016 at roughly 250 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2016 at roughly 200 extra TJ/d. However owing to the projected fall-off in generation load from 2017, usage of this capacity could be short lived.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2011 at roughly 100 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2011 at roughly 50 extra TJ/d.
- In the Low scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2015 at roughly 120 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2015 at roughly 75 extra TJ/d.

Figure 6-31 Estimated peak flow and capacity - Roma to Brisbane Pipeline (RBP) (TJ/day)

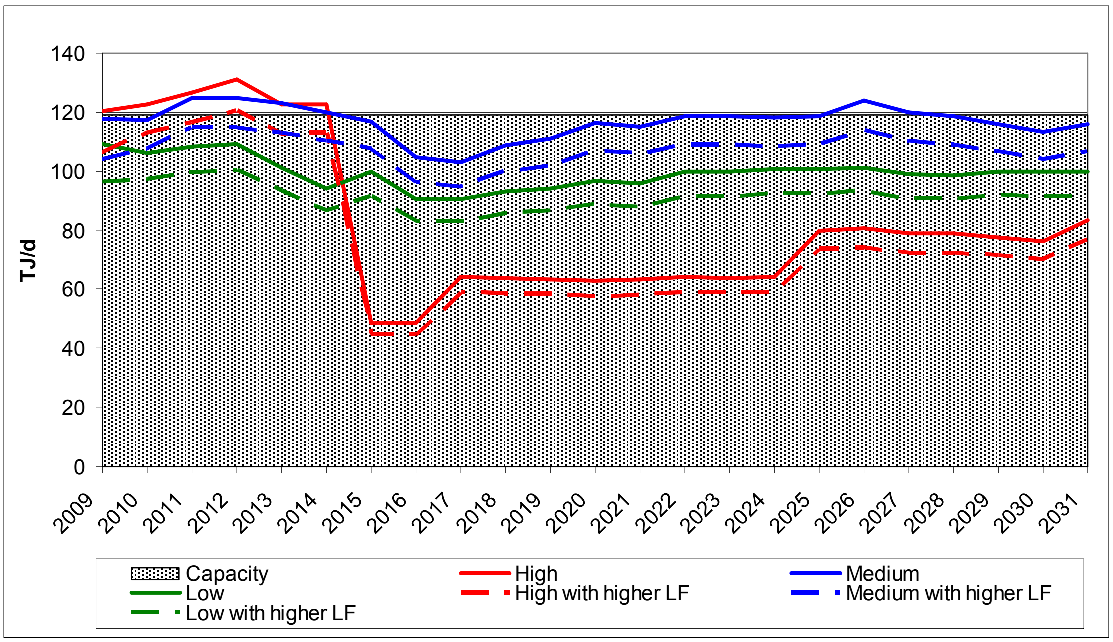


6.8.2.4 Carpentaria Gas Pipeline (CGP)

Figure 6-32 shows the projections of peak demand and capacity. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, no additional capacity is required regardless of the load factor assumption used. In this scenario the load in Mt Isa is projected to fall owing to connection of Mt Isa to the electricity transmission network.
- In the Medium scenario, no additional capacity is required regardless of the load factor assumption used.
- In the Low scenario, no additional capacity is required regardless of the load factor assumption used.

Figure 6-32 Estimated peak flow and capacity – Carpentaria Gas Pipeline (CGP) (TJ/day)

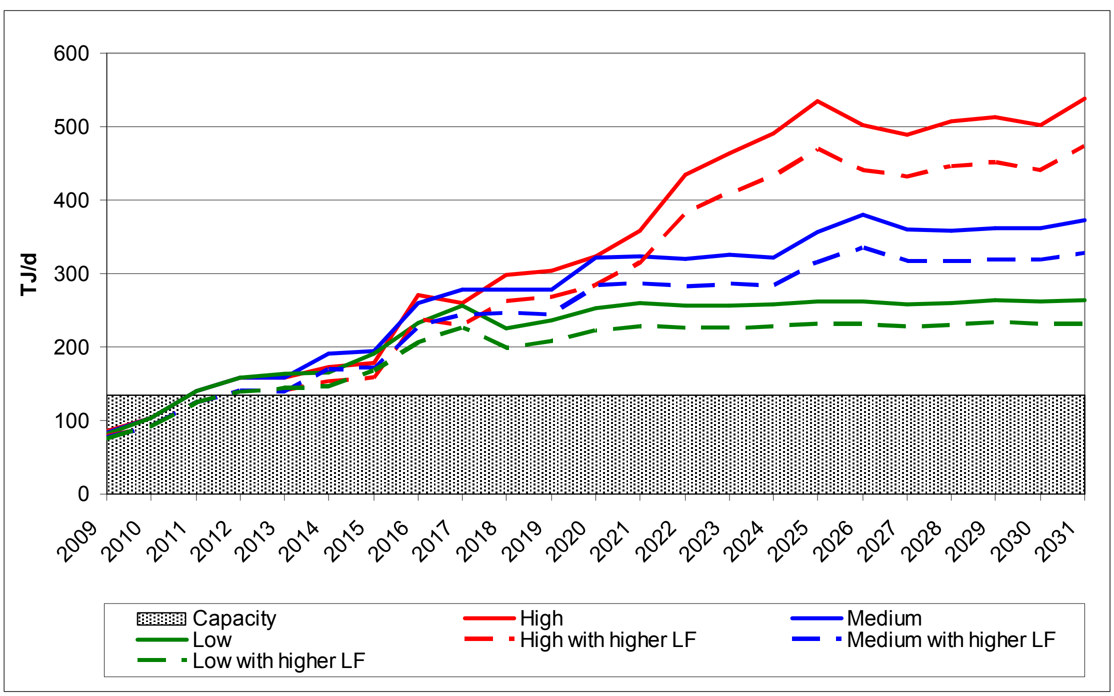


6.8.2.5 Queensland Gas Pipeline (QGP)

Figure 6-33 shows the projections of peak demand and capacity. Some of the incremental capacity requirements after 2014 could be substituted by LNG project pipelines. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2011 and peaking in 2025 at roughly 400 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2012 and peaking in 2025 at roughly 335 extra TJ/d. Some of the capacity requirements in this scenario are for the Townsville market, owing to potential Townsville supply from Moranbah being dedicated to LNG.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2011 and peaking in 2026 at roughly 250 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2012 and peaking in 2026 at roughly 200 extra TJ/d.
- In the Low scenario, additional capacity would be required at an increasing rate, starting in 2011 and peaking in 2017 at roughly 150 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2012 and peaking in 2017 at roughly 100 extra TJ/d.

Figure 6-33 Estimated peak flow and capacity – Queensland Gas Pipeline (QGP) (TJ/day)

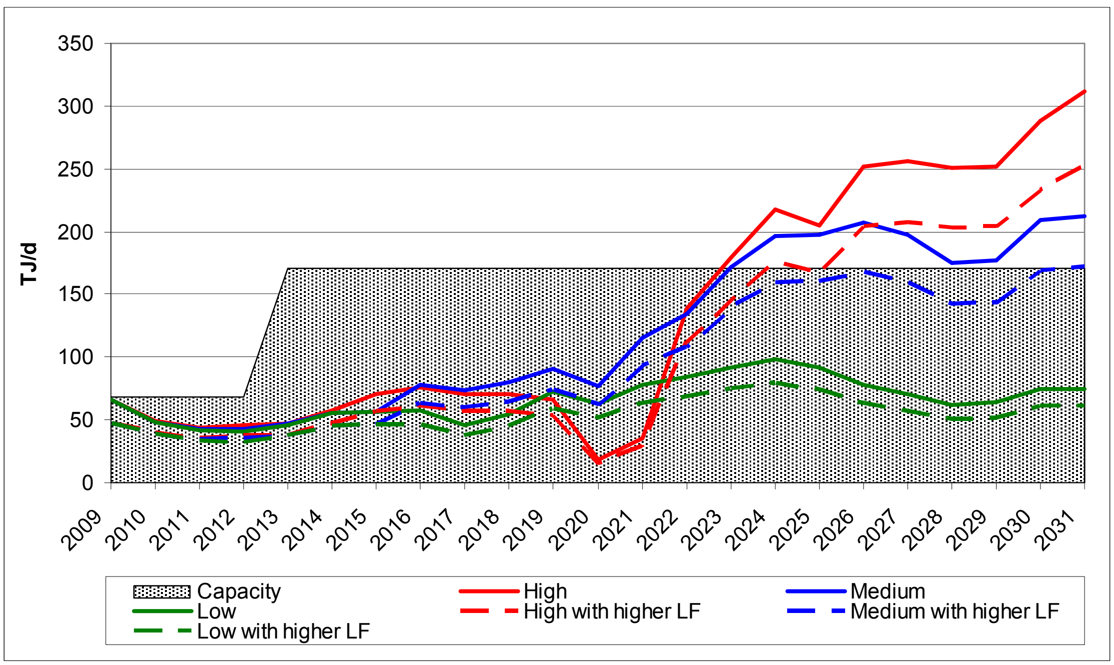


6.8.2.6 North Queensland Gas Pipeline (NQGP)

Figure 6-34 shows the projections of peak demand and capacity. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2023 and peaking in 2031 at roughly 140 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting in 2026 and peaking in 2031 at roughly 80 extra TJ/d.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2024 and peaking in 2026 at roughly 40 extra TJ/d. Under the higher load factor assumption, no additional capacity would be required.
- In the Low scenario, no additional capacity is required regardless of the load factor assumption used.

Figure 6-34 Estimated peak flow and capacity - North Queensland Gas Pipeline (NQGP) (TJ/day)

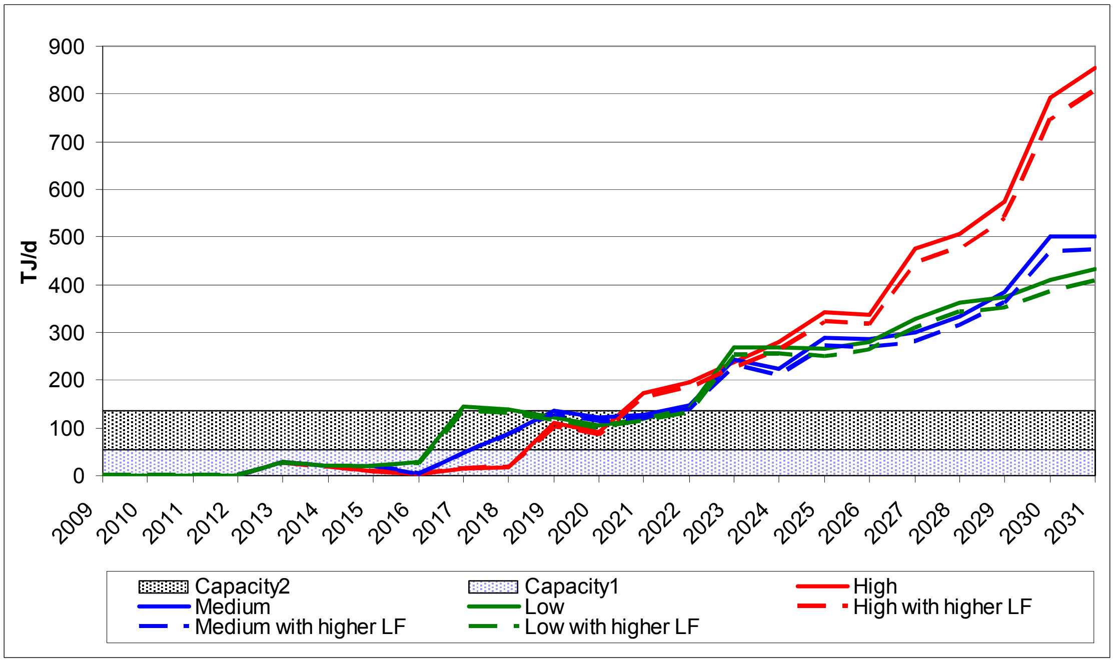


6.8.2.7 Moranbah to Gladstone Pipeline

Figure 6-35 shows the projections of peak demand and capacity. The capacity was obtained from an ABARE publication, *Minerals and energy: major development projects - October 2009 listing*, which lists the capacity of this pipeline to be between 20 to 50 PJ per annum depending on demand. However, much of the demand may be LNG related in which case its initial capacity will be considerably higher.

- In the High scenario, initial capacity of 20 PJ/annum would be sufficient until 2018. If we assume that additional capacity of 30 PJ/annum (to total of 50 PJ/annum) was to be built, then this would suffice until 2020. Thereafter, additional capacity would be required at an increasing rate peaking in 2031 at roughly 720 extra TJ/d. Under the higher load factor assumption, the same can be seen except the required additional capacity in 2031 was roughly 670 extra TJ/d.
- In the Medium scenario, initial capacity of 20 PJ/annum would be sufficient until 2017. If we assume that additional capacity of 30 PJ/annum (to total of 50 PJ/annum) was to be built, then this would suffice until 2021. Thereafter, additional capacity would be required at an increasing rate peaking in 2031 at roughly 365 extra TJ/d. Under the higher load factor assumption, the same can be seen except the required additional capacity in 2031 was roughly 335 extra TJ/d.
- In the Low scenario, initial capacity of 20 PJ/annum would be sufficient until 2016. If we assume that additional capacity of 30 PJ/annum (to total of 50 PJ/annum) was to be built, then this would suffice until 2022. Thereafter, additional capacity would be required at an increasing rate peaking in 2031 at roughly 280 extra TJ/d. Under the higher load factor assumption, the same can be seen except the required additional capacity in 2031 was roughly 260 extra TJ/d.

Figure 6-35 Estimated peak flow and capacity – Moranbah to Gladstone Pipeline (TJ/day)

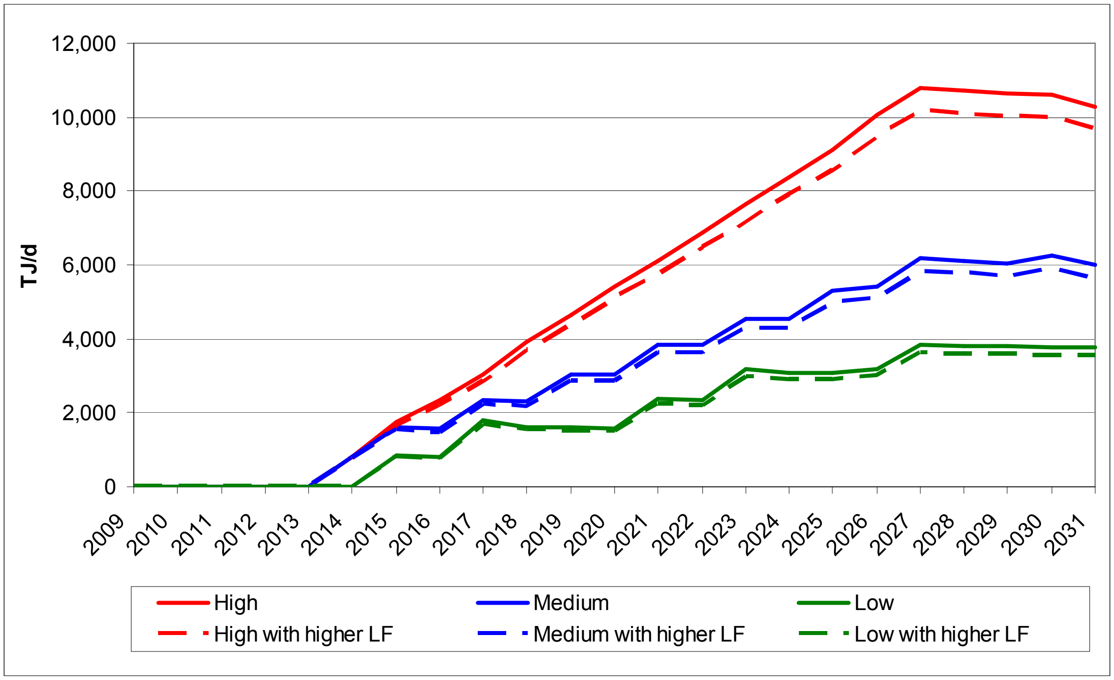


6.8.2.8 LNG Pipelines

The analysis done here is for the combined total of all LNG export pipelines. Figure 6-36 shows the projected peak demand under each of scenarios.

- In the High scenario, LNG export starts in 2014 and peaks in 2027.
- In the Medium scenario, LNG export starts in 2014 and peaks in 2027.
- In the Low scenario, LNG export starts in 2015 and peaks in 2027.

Figure 6-36 Estimated peak flow – Combined LNG export pipelines (TJ/day)

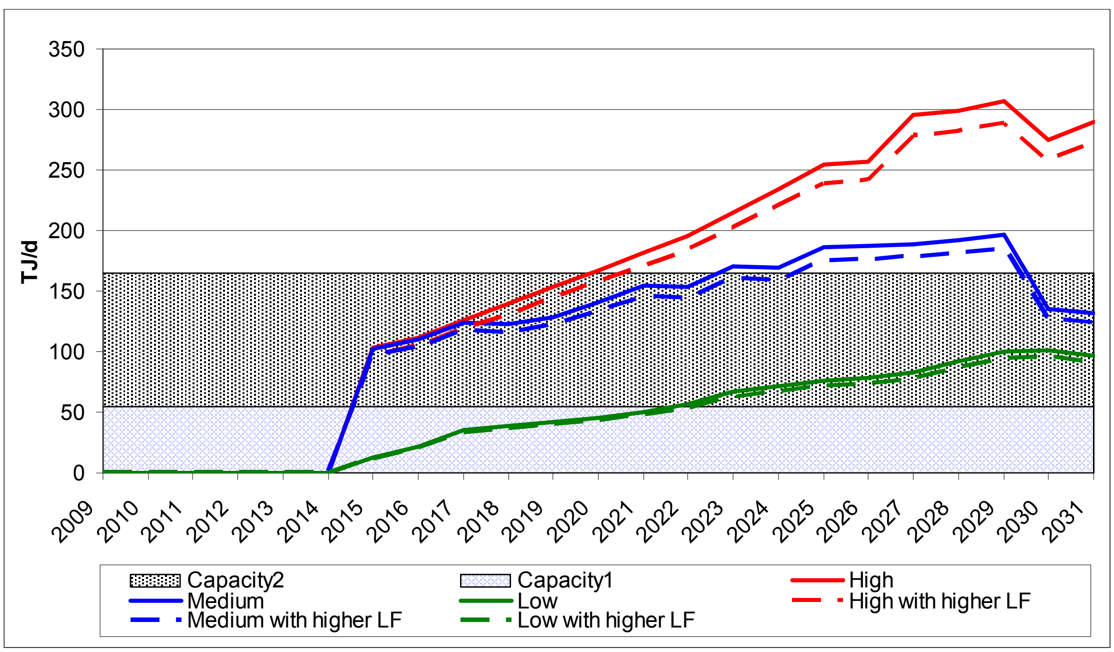


6.8.2.9 Lions Way Pipeline

Figure 6-37 shows the projections of peak demand and capacity. The capacity was obtained from a preliminary Environmental Impact Statement, which lists the capacity of this pipeline to be between 20 to 60 PJ per annum depending on demand. The pipeline is scheduled to be operational by 2015.

- In the High scenario, initial capacity of 60 PJ/annum needs to be built and this would suffice until 2020. Thereafter, additional capacity would be required at an increasing rate peaking in 2029 at roughly 140 extra TJ/d. Under the higher load factor assumption, the same can be seen except the required additional capacity in 2029 was roughly 120 extra TJ/d.
- In the Medium scenario, initial capacity of 60 PJ/annum needs to be built and this would suffice until 2022. Thereafter, additional capacity would be required at an increasing rate peaking in 2029 at roughly 30 extra TJ/d. Under the higher load factor assumption, the initial capacity would last until 2024, and additional capacity required thereafter to peak in 2029 at roughly 20 extra TJ/d.
- In the Low scenario, initial capacity of 20 PJ/annum would be sufficient until 2022. If we assume that additional capacity of 40 PJ/annum (to total of 60 PJ/annum) was to be built, then this would suffice until 2031 and no additional capacity is required. This is true for both load factor assumptions.

Figure 6-37 Estimated peak flow and capacity – Lions Way Pipeline (LWP) (TJ/day)

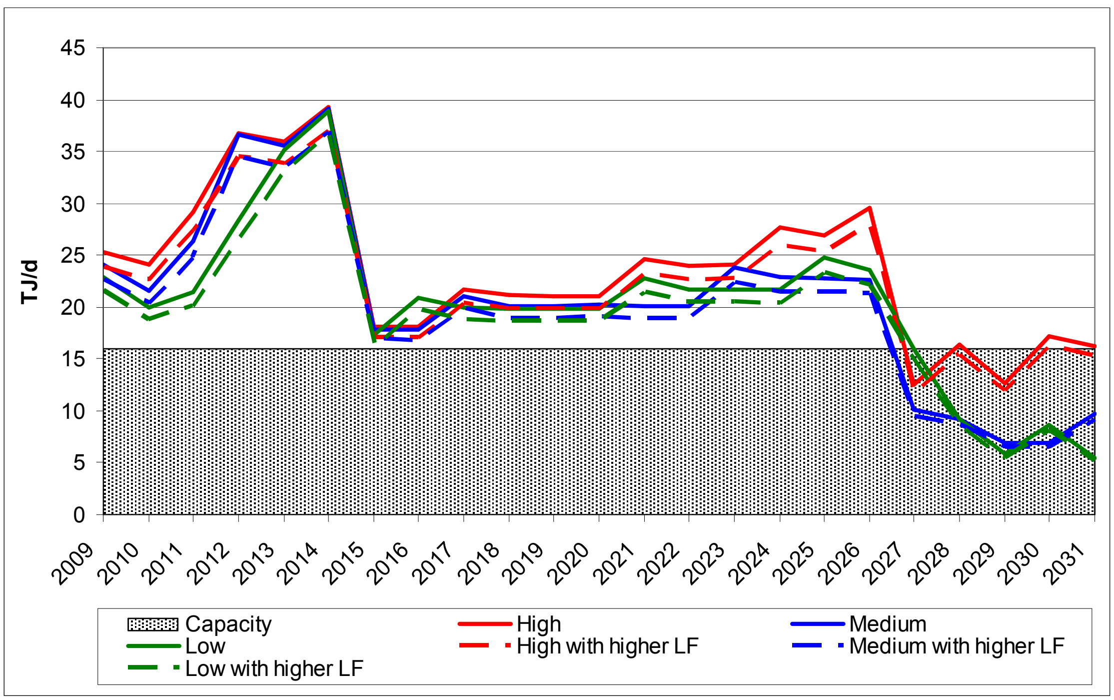


6.8.2.10 Dawson Valley Pipeline

Figure 6-38 shows the projections of peak demand and capacity. The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 23 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 20 extra TJ/d.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 23 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 20 extra TJ/d.
- In the Low scenario, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 23 extra TJ/d. Under the higher load factor assumption, additional capacity would be required at an increasing rate, starting now and peaking in 2014 at roughly 20 extra TJ/d.

Figure 6-38 Estimated peak flow and capacity – Dawson Valley Pipeline (TJ/day)



APPENDIX A MMAGAS

A.1 Key gas market modelling issues

The Australian wholesale gas market presents significant challenges to analysts seeking an understanding of its future evolution:

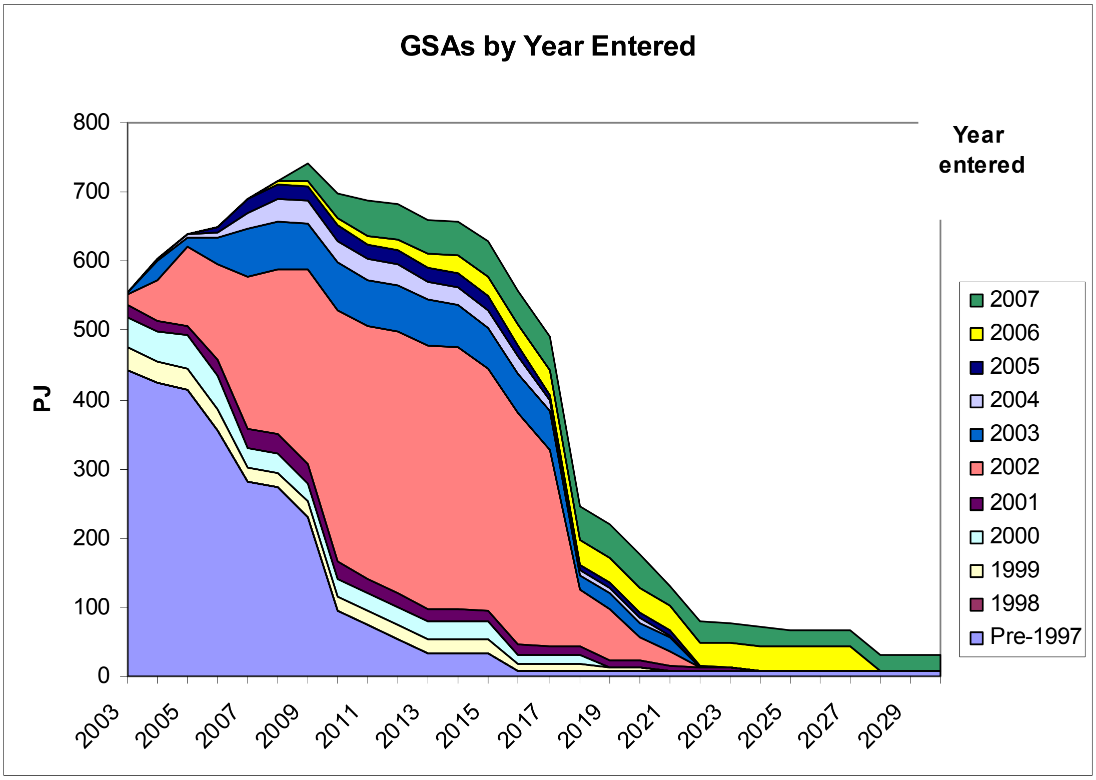
- The market structure is evolving and relationships are determined by participants rather than under formal market rules. Consequently the nature of the structure is not a given.
- Information on market transactions is held in confidence. Outline information is provided for ASX purposes but details are lacking.
- Public domain gas production cost information is very limited.
- Public domain gas reserves estimates are several years behind commercial developments.
- Gas demand forecasts are available only at the state level.

A.2 Market developments

The Australian gas market entered the competitive era in November 1997 with the signing of the Gas Pipelines Access Agreement and the promulgation of the National Third Party Access Code for Natural Gas Pipeline Systems. Under the Agreement and the Code, third parties have gained access to the natural gas delivery system and downstream market franchises have been progressively opened to competition.

No changes were legislated in the upstream, gas production, sector and initially the legacy gas supply agreements (GSAs) dating from the pre-competitive era continued to provide the majority of gas supply and to set the benchmarks for wholesale gas prices. Anticipating a decline in dedications from some of these agreements, a significant number of new GSAs have been reached, particularly since 2002, as illustrated in Figure A- 1.

Figure A- 1 Current Gas Sales Agreements, Eastern Australia



Prior to 2002, the concentration of ownership of gas reserves and production facilities resulting from the monopoly era gave rise to considerable uncertainty regarding the prices that would apply in new GSAs. In the short term however incumbents' market power has been limited by new entrants and the new agreements for supply to the southern states have been reached at headline prices[21] similar to those in legacy agreements covering supply from the Gippsland and Cooper Basins. New agreements for supply in Queensland have resulted in delivered prices below those in the Cooper Basin contracts dating from the mid 1990s. Many of the new entrants are developing gas supply in essentially new provinces, such as the offshore Otway basin and Queensland coal seam methane, from resources that have been discovered since 1997 due to the stimulus of market access.

Resource concentration nevertheless persists, together with the potential for market power to be exercised. Sale of gas at marginal costs, as in very competitive markets, is unlikely to occur and producers will make some additional profits above their cost of supply. These profits will depend on future levels of competition and create longer-term price uncertainty, which is a critical issue for all participants and policy makers, particularly in view of the role of gas in power generation and in reducing greenhouse emissions.

[21] The term "headline prices" refers to the price of gas under a GSA in $/GJ terms and does not take into account the value in a GSA created by non-price factors.

A.3 Market structure

The key transactions in the gas wholesale market are the long-term GSAs between producers and buyers such as retailers, generators and large industrials. Many recent agreements have been for a shorter term than the legacy agreements were when they were entered but the majority are for at least ten years and some are for fifteen years or more, as Figure A- 1 shows. Long-term GSAs are particularly important to new entrants, as they provide secure cash flows necessary to support investment in production capacity.

Short-term gas markets are undeveloped and illiquid in Australia at present and a recent ABARE study[22] has concluded that short-term market illiquidity will continue for the foreseeable future. In Victoria most of the gas bid into the spot market[23] is bid by buyers, sourced from long term GSAs with producers, hence the GSA prices play a significant role in determining the spot prices that apply to participants' imbalances.

These factors do not preclude the emergence of a short-term market, driven either by participants, perhaps in response to demand-supply imbalances, or by the gas market program initiated by the Ministerial Council on Energy. However they do suggest that a short-term market may be predominantly a secondary trading market, with longer-term GSAs ultimately determining gas prices.

Modelling future gas supply-demand and pricing therefore appears to be a question of modelling the formation of GSAs, as the need for further gas supply arises, or where new GSAs may displace existing GSAs. The critical question in constructing such a model is defining what is being competed for at any time:

- How far into the future?
- What volumes of gas?

The answer to the first question is given above – typically ten to fifteen years. The volume issue is more complex however. Figure A- 1 shows that much more gas was being competed for in 2002 than in subsequent years, in which new GSAs appear to provide approximately one year's additional market cover.

Ideally, a model such as MMA-Gas would itself estimate the market structure based on the risk/reward factors considered during GSA negotiation. As a first stage in model development however the market structure is treated as an input:

- The length of new GSAs is fixed, typically at ten years, reflecting the likelihood that future terms may be shorter
- The volume competed for is based on incremental market requirements, i.e. the difference between projected demand and the then current GSAs, for a defined period, such as one, two or five years.

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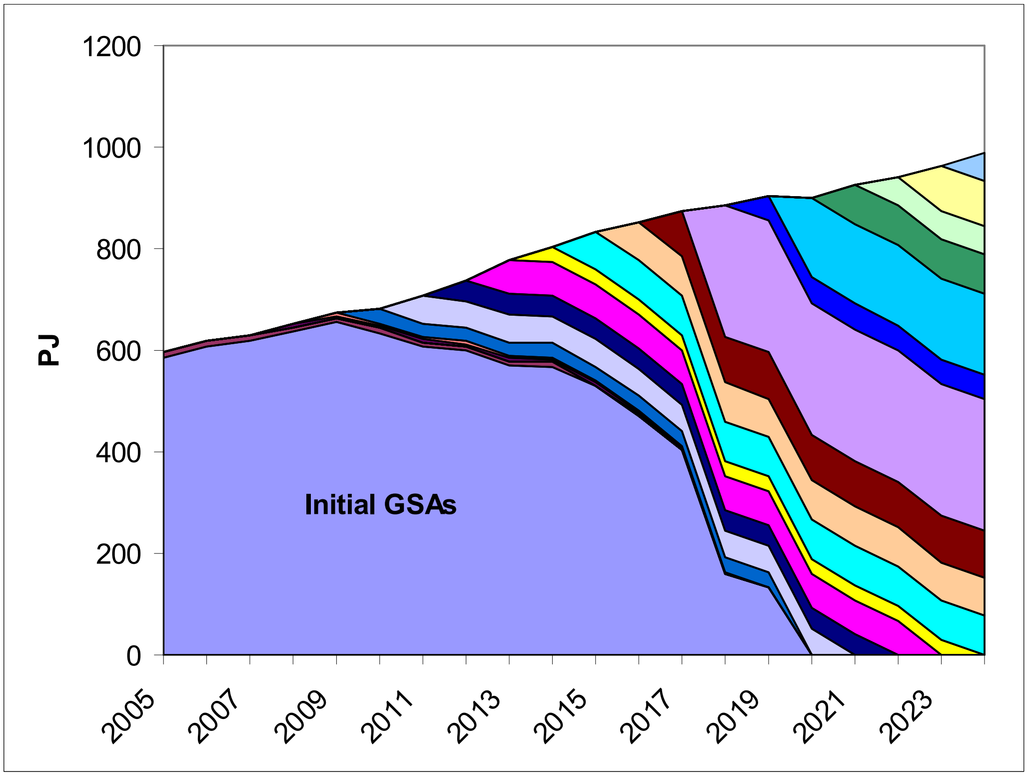
22 Australian Gas Markets, moving towards maturity, ABARE December 2003.

23 The Victorian gas spot market was established in 1999 as part of a price-based gas scheduling and transmission balancing regime

The market is therefore modelled as a sequence of discrete competitive events, at intervals equal to the period defining the volume being competed for. The build up of GSAs is illustrated in Figure A- 2. The competitors are all the gas producers who have uncontracted reserves that can be produced in time to meet the incremental market requirements, including both existing producers and potential new entrants.

Figure A- 2 MMA-Gas projected GSA build up



By implication, the competition for new GSAs is assumed to take place some years ahead of the market requirement, otherwise new entrants would not be able to supply in time and would not ever be able to enter the market. This matches the current reality and is an essential assumption if realistic projections are to be made. However, it does also mean that the model reflects an "orderly development" scenario in which demand and supply are never significantly misaligned, for example to the extent that additional supply is needed at short notice or demand falls below GSA "take-or-pay" levels.

This model of competition is not forward looking in the sense of explicitly considering multiple periods, because of the difficulty of defining what the appropriate multiples are. However, repeated competition for single periods by producers whose potential capacity and cost parameters change slowly produces results that look very similar to multi-period competition.

Although, GSAs are typically for gas ex-plant, the markets are effectively at the city gates, where the price of gas is the explant price plus the transmission cost. Competition is therefore modelled at the city gate and transmission costs are included as a cost of production. This is consistent with the current transmission paradigm under which pipelines are price regulated or subject to threat of regulation. Further work is required to develop models with explicit transmission price competition.

A.4 GSA price formation

In negotiating new sales agreements the commercial objectives of the producers are to maximise their profits, by controlling volumes and prices, subject to competitive pressures exerted by other existing and new producers and by the willingness of the market to buy gas at those volumes and prices.

The buyers' commercial objectives are likewise to maximise their profits, which is generally equivalent to minimising their supply costs, including transmission. By negotiating several years ahead of the market's requirement for new gas, buyers can involve new entrants, without whose presence in negotiations the incumbents would have greater market power and would extract higher prices.

Gas producer competition is consequently a type of game, a situation in which two or more players make decisions contingent on the other players' decisions. MMA-Gas therefore models the gas market, i.e. the competition between producers to contract for new GSAs, as a Nash-Cournot game between the producers, this being a mathematically tractable game model that is particularly suited to modelling competition between a limited number of players.

Game theory models have been extensively applied to electricity markets[24] but their application to gas markets appears very limited. At the time we initiated MMAGas development we were not aware of any similar gas models but have since discovered the work of Gabriel et al[25], who have built a model of the North American market in which the producers are modelled as being in perfect competition and marketers/shippers are modelled as Nash Cournot players with market power. Our assumptions about sector competitiveness are the reverse, which we believe are more appropriate in the Australian market.

A.5 MMA-Gas Structure

MMAGas replicates the essential structure of the Australian gas market. Particular emphasis is placed on ensuring that gas supply is rational, for example capacity investments are made only when there are sufficient remaining reserves for the investment to earn a return. This, combined with the Nash-Cournot game solution, ensures that all capacity investments projected in MMA-Gas are automatically economic i.e. earn a return at least equal to producers' cost of capital.

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24 See for example: "Network-constrained Cournot models of liberalised electricity markets: the devil is in the details". K Neuhoff, JBarquin, MG Boots, A Ehrenmann, BF Hobbs, FAM RIjkers and M Vasquez. Energy Economics May 2005. Also "Game Theory Models in Plexos". Michael S Blake, Drayton Analytics, 2003.

25 "A large scale linear complementarity model of the North American natural gas market", SA Gabriel, J Zhuang, S Kiet, Energy Economics July 2005.

The following sections describe the "default" version of MMA-Gas in which new GSAs have a ten year term and the competition periods are annual.

A.5.1 Demand

Demand is specified for a number of different zones, with demand in each zone treated as if at a point, so there is a single transmission cost from each producer to each zone. The zones are primarily the state gas markets, with further subdivisions as necessary to accurately differentiate intra-state transmission costs.

The Eastern states model has eight demand zones, shown in Table A- 1. MMA-Gas can readily accommodate additional Eastern states zones, the major limitation being availability of disaggregated forecasts. Versions including Western Australia and LNG exports have also been developed.

Table A- 1 Eastern states demand zones and nodes

Zone	Node
NSW and ACT	Sydney
Victoria	Melbourne
SE Queensland	Brisbane
Central Queensland	Gladstone
NE Queensland	Townsville
NW Queensland	Mt Isa
Queensland CSG	Tarong
South Australia	Adelaide
Tasmania	Bell Bay
LNG exports	Gladstone

Underlying demand projections for each market zone are input. Underlying projections means projections at current prices, which are price adjusted to match supply. Each market is characterised by a price elasticity, which depends largely upon the balance of demand in various sectors. MMA's projections combine ABARE residential, commercial and industrial projections with MMA forecasts of generation usage.

A.5.2 Gas production

The Eastern states model incorporates twenty competing producers. In MMA-Gas producers are physically independent gas producers, such as the BHPB-Esso JV in Gippsland and the Santos led JV in the Cooper Basin. It is assumed that the JVs have sufficiently different ownership mixes that they operate commercially independently, i.e. bid competitively, regardless of common ownership. We believe this will be reasonably true in future though it may not have been under the state-by-state monopoly conditions in the past. Alternative assumptions about production competition have been investigated and can be modelled.

A.5.3 Gas reserves

Each producer's existing 2P (proved and probable) gas reserves are split into two tranches, lower production cost (Tranche 1) and higher production cost (Tranche 2), corresponding broadly to reserves that are commercial at current prices and uncommercial reserves. Initial T1 and T2 gas reserves are input as data.

Future gas discoveries are dealt with using a simple sub-model based on estimated undiscovered resources (choice of P80, P50 and P20 values i.e. 80%, 50% and 20% probability of exceedance over the next thirty years, assuming steady exploration expenditure). The sub-model adds new gas discoveries to each producer's reserves, up to the selected level of undiscovered resources, with timing of discoveries determined by a value index related to remaining reserves and costs of exploration. Discoveries are added to both T1 and T2 reserves.

Each year reserves are decreased by the quantity produced and increased by new discoveries.

A.5.4 Production costs

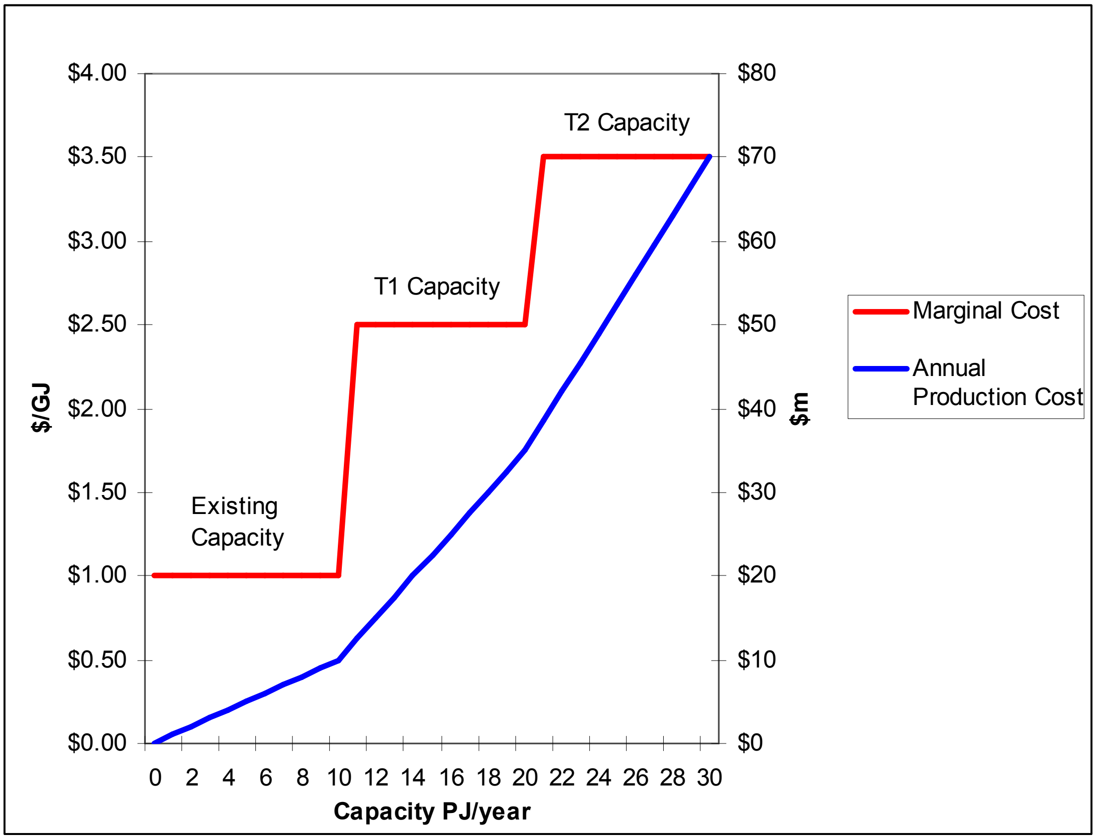
MMA-Gas focuses on producer's costs of supplying new GSAs over a fixed term of ten to fifteen years. These costs are determined by whether the incremental capacity used to supply the new GSAs is existing capacity or potential incremental capacity available from uncontracted T1 and T2 reserves. Each producer's new GSA supply cost function is therefore specified by the marginal costs of incremental production from existing capacity (short-run marginal cost), potential T1 capacity (long-run T1 marginal cost) and potential T2 capacity (long-run T2 marginal cost, higher than T1).

Figure A- 3 illustrates a typical MMA-Gas production cost function for a producer with the ability to supply new GSAs up to 10 PJ/yr from each of existing, potential T1 and potential T2 capacity. The production cost functions are redefined each year to reflect changes in uncontracted reserves. Each producer's ability to supply is constrained only by its costs – in MMA-Gas implementation the cost of production beyond T2 is simply set at an uncompetitive level to ensure that capacity used never goes beyond T2.

Further realism is added by splitting capacity/costs into field capacity/costs and processing capacity/costs. Field capacity is assumed to be tied to a GSA i.e. new GSAs generally need new field capacity but processing capacity is assumed to last for thirty years.

All production costs are inputs. As the model is a long-term model, producer costs include annualised costs of capital (typically assumed to be 12% real pre-tax) and are based on an assumed "market" load factor e.g. 85%.

Figure A- 3 MMA-Gas production cost function



Production costs are generally assumed to be fixed in real terms into the future but can be varied up or down to reflect underlying cost changes due to exchange rates or technical developments. Cost increases due to use of reserves that are more expensive to develop are taken into account by the T1/T2 split.

Initial gas production and processing capacity attributable to each producer are also input as data. Default data is based on MMA information.

A.5.5 Transmission costs

In the current version of MMA-Gas transmission pipelines are treated as a common carriage system used by producers. Transmission contracts are not dealt with explicitly but new transmission contracts are created implicitly each time a new GSA between a producer and a market is created.

Transmission costs are added to production costs to determine producer competitiveness in each market. In view of the long-term nature of MMA-Gas there are no transmission constraints because transmission capacity has to be expanded to meet demand, in the same way production capacity is expanded. Costs are expressed in $/GJ throughput terms, with the same costs for existing and new capacity.

Transmission costs are inputted as costs for specific pipelines, e.g. Roma-Brisbane pipeline, and combined to form producer-to-market transmission costs. The values used are based on regulated or voluntary third party tariffs, where these are published, otherwise MMA estimates based on construction costs are used.

A.5.6 Gas supply agreements

Existing GSAs

Volumes and prices of existing GSAs are inputted as data. MMA's GSA database is used to allocate volumes available under GSAs to each market.

New GSAs

For each year in the projection period the GSA shortfall/surplus relative to demand in each market zone is calculated. The shortfall can be calculated relative to GSA volumes anywhere from ACQ (annual contract quantity) down to take-or-pay, typically 80% of ACQ.

Producers compete to meet the GSA shortfalls in that year. In some years there is no shortfall in some zones and in other years there are substantial shortfalls as GSAs terminate. When the shortfall is measured against GSA volumes below ACQ, the residual volumes of gas available under existing GSAs compete with new GSAs to supply the shortfall quantity, with the cost of supply under existing GSAs set at the short-run marginal cost.

Each producer's competitive objective is to maximise its profit subject to the volume/price constraints imposed by competitors. Their profits are the sum of revenue in each market (volume x market price at city gate) less their long-run incremental production costs and transmission costs to each market. Competition is across all zones simultaneously. The model automatically seeks to supply from existing capacity, followed by T1 reserves until they are fully contracted and lastly from T2 reserves.

Profit maximising incremental GSA volumes and market prices are estimated according to the Nash-Cournot game methodology, together with price adjusted demand forecasts. New GSA prices at the plant gate are market prices less transmission costs. The new GSA price always exceeds the production costs, otherwise the incremental gas quantity would be zero, and consequently the new production is guaranteed to be economic at the margin, i.e. to earn a return at least equal to the producer's cost of capital embedded in its costs. The excess profit margins are, at least in part, used to cover other producer costs such as exploration.

Incremental GSA volumes are assumed to be contracted for ten years. Consistent with this assumption, producers cannot contract more than 10% of their remaining uncontracted reserves in any year. The plant gate price is also locked in for the ten years. The new GSAs are added to existing GSAs and the process is repeated for the following year, thus building up layers of new GSAs, as illustrated in Figure A- 2.