Gas Demand Study

An assessment of demand for Coal Seam Gas and pipeline services in Central Queensland

Prepared for QGC/BG International

Public Version – 6 December 2009

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 6, 224-236 Queen Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9600 3155
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Darwin
Suite G1, Paspalis Centrepoint
48-50 Smith Street
Darwin NT 0800
GPO Box 908
Darwin NT 0801

Telephone (+61 8) 8943 0643
Facsimile (+61 8) 8941 0848
Email darwin@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Paul Balfe
Telephone (07) 3009 8715
Mobile 0404 822 317
Email p.balfe@aciltasman.com.au

Contributing team members:
Owen Kelp
Peter Crittall

Contents

List of boxes

No table of figures entries found.

List of figures

List of tables

Executive summary

ACIL Tasman was engaged by QGC to undertake a market study in support of QGC's planned application under s.151 of the *National Gas Law* 2008 for a 15-year no-coverage determination that will exempt the QCLNG Export Pipeline from being a covered pipeline for purposes of third party access. The Export Pipeline will carry CSG from the production fields to the LNG liquefaction plant on Curtis Island, near Gladstone.

Downstream markets

The main downstream gas market potentially serviced by the QCLNG Export Pipeline is the industrial centre of Gladstone. From Gladstone, pipeline connections to Rockhampton approximately 90 km to the north and to the Wide Bay region (Bundaberg, Hervey Bay, Maryborough) some 300 km to the south could potentially allow gas delivered via the QCLNG pipeline to serve these smaller markets as well.

Other pipelines

These markets are already served by the Queensland Gas Pipeline (QGP), including the Rockhampton Branch Line, and the Gladstone – Wide Bay Pipeline.

There are several other LNG export proposals currently under investigation in the Gladstone region. If these projects were to proceed as currently proposed, further dedicated pipeline connections would be constructed linking the CSG fields of the Surat and Bowen Basins to Gladstone.

Gas demand in the downstream markets

The current levels of gas consumption in the relevant downstream markets are as follows:

- Gladstone – 24 PJ/a
- Rockhampton – 1.6 PJ/a
- Wide Bay – approximately 0.3PJ/a

On the basis of proposed new industrial loads and expansion of existing mineral processing sites, demand at Gladstone is expected to grow to around 64 PJ/a by 2014. After this date, there is an apparent levelling out of demand at Gladstone. However, this is an artefact of the planning horizon for large industrial projects of this type, rather than an indication that the Gladstone market will have reached any form of natural size limit. There may well be further growth in gas demand at Gladstone post 2015 but no emergent demand has been included in the projections because any such growth would, at this stage, be purely speculative.

The small retail loads in Rockhampton and Wide Bay are expected to grow in line with regional economic and demographic growth, but will remain small in absolute terms.

Gas prices in the downstream markets

Wholesale delivered prices into Gladstone and Rockhampton are presently estimated to be in the range A$3.50 to A$4.50/GJ (real 2009 dollars), including transport cost on the QGP of A$0.80 to A$1.00/GJ, depending on customer load factor. The cost of gas to retail customers is considerably higher, because as well as the cost of the gas ex field and transmission pipeline costs, customers also pay for low-pressure distribution and retail charges.

Impact of relevant government policies

The report includes discussion of the implications of government policies for future gas demand, including the Carbon Pollution Reduction Scheme (CPRS), expanded Renewable Energy Target (RET), and the Queensland Government Domestic Market Obligation.

CPRS

CPRS is expected to be directionally very positive for gas demand, because it tilts the economics of electricity generation and large-scale industrial heating away from coal and toward less emission-intensive energy sources, including gas. CPRS will also result in higher sustainable gas prices because of improved competitiveness with coal on a carbon-inclusive basis. CPRS is estimated to increase the wholesale price of gas by around A$1.00/GJ for each A$30/t CO2e carbon price.

RET

The expanded Renewable Energy Target (RET), on the other hand, will tend to suppress consumption of gas for power generation, but will drive a need for additional open-cycle gas-fired peaking plant as back-up to unreliable wind generation. The RET scheme is unlikely to have a great effect on gas demand in the Gladstone region because the only currently proposed gas-fired generators are the proposed QAL and Comalco cogeneration facilities, and there is a lack of good quality wind generation sites in Central Queensland.

Domestic Market Obligation

The Queensland Government during 2009 considered introduction of a "domestic market obligation" requiring LNG project proponents to set aside up to 20% of their CSG reserves for local domestic purposes. For a three-train development of QCLNG with a total LNG feed gas requirement of 690 PJ/a, such a policy would have required dedication of up to 2,750 PJ of additional reserves, sufficient to support 138 PJ/a of domestic production which is close to the total current consumption of gas in Queensland. Such a policy would have increased the risks for the QCLNG Project with regard to reserves establishment, potentially delaying the process of proving up enough reserves to allow the LNG project to proceed. On 14 November 2009 the Queensland Government announced that, rather than impose a domestic market obligation on LNG proponents, it would move to set aside areas prospective for CSG that could be released to meet future domestic gas market requirements.

Gas market modelling

The latter part of chapter 2 sets out the results of modelling two LNG development scenarios: a "Project Case" involving development of the first two LNG trains proposed by QGC (and a sensitivity case assessing the impacts of a third train); and an "Industry Case" that includes the three QCLNG trains plus a further four LNG trains built by other proponents and involving two additional LNG export pipelines.

All three scenarios show that anticipated gas demand in the downstream markets is substantially satisfied throughout the modelling period (to 2030) without utilisation of the QCLNG Export Pipeline for carriage of gas to domestic markets.

Importantly, the modelling results show that all gas delivered into the Gladstone market is transported via the existing Queensland Gas Pipeline (QGP), rather than the QCLNG Export pipeline. No gas is delivered to the Gladstone domestic market via the QCLNG Export Pipeline—even on a short term basis during the ramp-up to full LNG production—because QGP provides a more economical transport pathway.

Modelling of gas prices under the three scenarios shows some softening of real prices in the short term, as a result of excess ramp gas being available in the market. Prices then rise from a low of around A$4.50/GJ delivered at Gladstone prior to commissioning of the LNG facilities to around A$5.30 (real, 2009) by 2030 in the "Project Case", and around A$5.75/GJ (real, 2009) in the "Industry Case".

CSG LNG Projects

Since early 2007, at least six LNG proposals based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been announced. Chapter 3 provides short summarises of each of the main LNG proposals. The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant. Total proposed capacity is initially 16.8 mtpa, rising to 40.6 mtpa if plans are fully developed to their ultimate potential.

Small CSG producer assessment

Chapter 4 considers the question whether other CSG producers in the vicinity of the proposed QCLNG Export Pipeline would be likely to benefit significantly from having access to the pipeline. The analysis focuses on those small or emerging CSG producers that are not involved with the various CSG LNG Projects currently proposed, recognising that for those "non-aligned" producers access to an alternative path to market might enhance the prospects of successfully commercialising the CSG within their exploration areas.

The analysis identifies six companies not currently involved in LNG proposals that have CSG resources or exploration areas prospective for CSG that are located within 100 km of the proposed QCLNG Export Pipeline and associated facilities.

However, none of these resource and prospect holders are likely to find that access to the QCLNG Export Pipeline would offer a commercially attractive means of reaching prospective customers compared to the alternatives already available. This is principally because of the tie-in distances, given that most prospects are closer to either the QGP (via the Dawson Valley Pipeline) or the Roma to Brisbane Pipeline (RBP). Other factors mitigating against third party use of the QCLNG Export Pipeline include the short term and/or interruptible nature of the services that could potentially be made available; the need for the third party shipper/s to meet capital costs of offtake facilities, and the fact that the export pipeline will carry gas of a more exacting specification than the general Australian Standard for sales gas.

QGP transport cost assessment

Chapter 5 provides information on the existing Queensland Gas Pipeline (QGP), owned and operated by Jemena Limited, and on the costs associated with transporting gas to the relevant markets via the QGP.

For existing users with contracts in place prior to enactment of the National Gas Law (NGL) on 1 July 2008, charges on the pipeline are limited by a rate cap of A$0.795/GJ of capacity reserved. In order to supply the expansion at Comalco's Yarwun refinery (22.8 PJ/a), Jemena is undertaking a significant expansion of the QGP that will increase capacity from the initial 25 PJ/a to 52 PJ/a by April 2010. On commissioning of this expansion, the rate cap for pre-NGL contracts will fall to A$0.71/GJ.

For new users after 1 July 2008, the charge for firm capacity is A$0.795/GJ (as at 1 July 2008) indexed by CPI on 1 January each year. No rate reduction will apply after expansion.

CSG LNG transportation cost assessment

[Confidential]

Costs to access other pipelines

In order to understand the market options that may be available to producers in the Surat/Bowen Basin, this chapter considers what other existing pipelines could be accessed, and at what cost. Two hypothetical gas producers are considered:

- Surat/Bowen Producer A, located 50km northeast of Wallumbilla, with an assumed production capability of 10 PJ/a
- Surat Producer B, located 25 km south of the Roma-Brisbane Pipeline mid-line, with an assumed production capability of 5 PJ/a

The costs for these producers to access different markets in Eastern Australia are made up of two components:

- Costs associated with tying in to the existing gas transmission network, including costs of the lateral pipelines and facilities costs for compression, metering etc (note that the latter costs are likely to be similar irrespective of what pipeline the producers tie in to).
- Tariff charges for transportation on existing third-party transmission lines.

For the two model cases, the tie in costs range from A$9.75 to A$27.5 million, with a corresponding unit tariff range of A$0.20 to A$0.28/GJ. Costs for transportation on third-party pipelines vary widely, depending on target market location and on load factor. The total estimated range of third-party tariff costs is from A$0.74 for transport to Brisbane, up to A$2.39/GJ for transport to Mt Isa.

The analysis highlights the fact that CSG producers in the Surat and southern Bowen Basins will generally have options to pursue markets throughout Eastern Australia via the existing gas transmission pipeline network.

1 Introduction

Chapter Summary

This chapter explains the basis on which ACIL Tasman was engaged by QGC to undertake this market study in support of QGC's planned application under s.151 of the National Gas Law 2008 for a 15-year no-coverage determination on the Export Pipeline that will carry CSG from the production fields to the LNG liquefaction plant at Gladstone.

The chapter provides a brief overview of the Queensland Curtis LNG Project; explains the scope of the market study; and sets out ACIL Tasman's qualifications to prepare the study.

QGC, a wholly-owned subsidiary of the BG Group, plans to build a 380km gas pipeline from its CSG production area located in the vicinity of the town of Miles to its proposed Queensland Curtis Liquefied Natural Gas facility near Gladstone (QCLNG). ACIL Tasman was engaged by QGC to prepare a study of gas markets downstream of the coal seam gas (CSG) fields that will supply gas to the LNG project. The purpose of the study is to support an application by QGC under s.151 of the *National Gas Law 2008* for a 15-year no-coverage determination that will exempt the pipeline from being a covered pipeline for purposes of third party access.

1.1 The Queensland Curtis LNG Project

The QCLNG project is an integrated resource development project involving large scale production of CSG from fields located in the Surat Basin region of southern Queensland; transportation of the gas by pipeline to a liquefaction facility located on Curtis Island, near Gladstone; production and storage of LNG at the liquefaction facility; and shipping facilities to allow loading of LNG onto ships for transportation to overseas customers. The following summary of the QCLNG project is drawn from the Executive Summary of the QCLNG Environmental Impact Study (QGC, 2009).

The QCLNG Project includes the following components:

- Gas field
- Pipeline
- LNG component
- Shipping operations (wharfage and load out)
- Ship swing basin and channel component

The Project is anticipated to have a life of at least 20 years.

The **Gas Field Component** of the QCLNG Project will involve development of approximately 6,000 gas production wells over the life of the project with initially up to 1,500 wells by mid-2014. In addition to the CSG production wells, the upstream gas field component of the project includes:

- associated surface equipment, such as wellhead separators, wellhead pumps, telemetry devices and metering stations
- gas-gathering systems
- gas processing and compression infrastructure
- field infrastructure such as access tracks, warehouses, camps (both construction and operations), office and telecommunications
- water-gathering and water management infrastructure and water treatment facilities.

The **Pipeline Component** of the QCLNG Project includes:

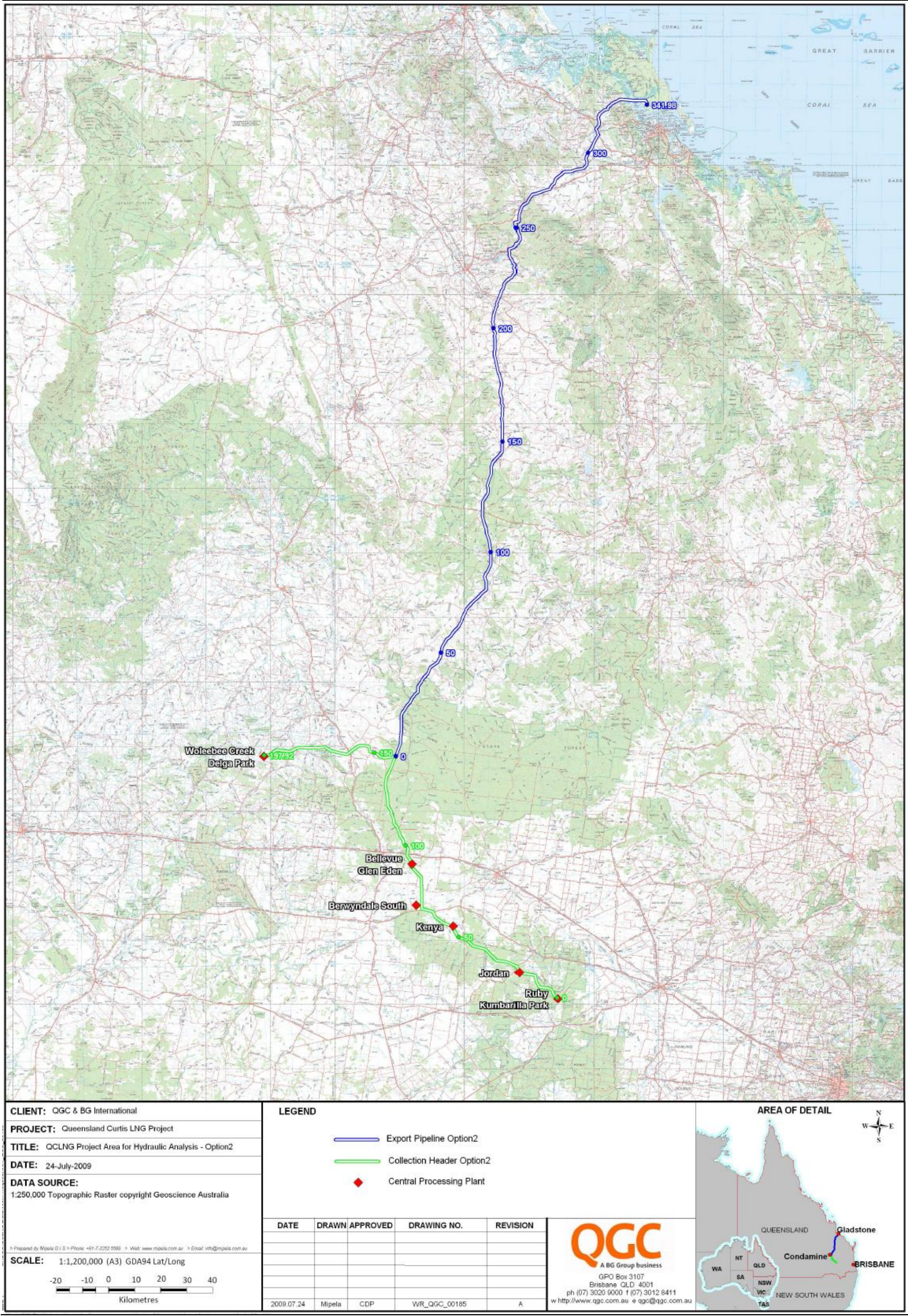
- a 380 km Export Pipeline from the gas fields in the Surat Basin of southern Queensland to the LNG Facility on Curtis Island
- a 200 km Collection Header – a central pipeline located in an Upstream Infrastructure Corridor (UIC) to collect gas from centralised compressor facilities for delivery to the Export Pipeline.

The indicative location of the Pipeline Component is shown in Figure 1. Note that the western lateral pipeline (indicated in purple on this map) will not be constructed when the QCLNG facilities are commissioned.

The **LNG Facility** will initially comprise two processing units, or "trains", with provision for a third train. Nominal production capacity with three trains operating will be up to 12 million tonnes per annum (mtpa) of LNG. QGC plans to commission Train One in late 2013 and Train Two approximately six to 12 months later. Timing of the third parallel train is uncertain.

The current project design provides for the delivery of approximately 1,360 million standard cubic feet per day (mmscfd) or approximately 530 PJ/a of compressed CSG to the LNG Facility via the Export Pipeline and its associated infrastructure for supply to the first two LNG trains. A decision to develop the third train would increase the gas delivery requirement to around 2,040 mmscfd or 795 PJ/a.

Figure 1 **Indicative route for the QCLNG gas transmission pipeline**



Source: QGC

1.2 Scope of the market study

The market study is intended to examine gas consumption in all relevant downstream markets ("Downstream Markets") associated with the QCLNG transmission pipeline ("Pipeline") for the period 2009-2030, the prices of gas in those markets, and the supply already committed. The study focuses on the Gladstone market but includes consideration of secondary markets in the region, including Rockhampton to the north, Bundaberg to the south, and Moura to the west.

In modelling future gas market scenarios, ACIL Tasman has, unless otherwise stated, used the same assumptions incorporated into the modelling for the *Gas Market Review and Outlook 2009* Report prepared for BG International, dated April 2009.

The study scope includes the following sections:

A. Downstream Markets projected gas demand and prices over the period 2009 – 2030, including impact of government policies on domestic gas supply and demand

B. LNG Export Market over the period 2012 – 2030

C. Small CSG producer assessment

D. Cost of using and expanding the capacity of the existing Queensland Gas Pipeline (QGP), owned and operated by Jemena Ltd, to bring the gas of CSG producers to the Gladstone market

E. Cost of using CSG-LNG pipelines to bring gas to the Gladstone export market

1.3 ACIL Tasman's qualifications

ACIL Tasman is one of the largest specialist economics and policy consultancy businesses in Australia. The firm has extensive experience in the gas industry, both in Australia and internationally. This experience covers areas including policy development, market analysis and the provision of economic and commercial advice to public and private sector clients. The firm's analytical and advisory services to the gas industry encompass the entire supply chain—from gas producers, pipeline operators, gas distributors and retailers—to major customers such as power stations and industrial facilities, as well as investors, developers and financiers.

This study has been prepared by a team of ACIL Tasman's energy market specialists led by Paul Balfe, an Executive Director of ACIL Tasman who has overall responsibility for the firm's gas business. The other members of the ACIL Tasman consulting team contributing to the study were Owen Kelp

(Senior Consultant), Peter Crittall (Senior Associate) and Martin Pavelka (Analyst).

Summary curriculum vitae information for the team members is set out in Appendix B.

2 Downstream market projections to 2030

Chapter Summary

The main downstream gas market potentially serviced by the QCLNG Export Pipeline is the industrial centre of Gladstone. From Gladstone, pipeline connections to Rockhampton in the north and to the Wide Bay region (Bundaberg, Hervey Bay, Maryborough) in the south could potentially allow gas delivered via the Pipeline to serve these smaller markets as well. The Moura market, which lies approximately 75 km off the QCLNG pipeline, is currently supplied from the adjacent Moura – Dawson River CSG fields. Moura also has existing access to gas supplied via the Queensland Gas Pipeline. For this reason, Moura is not further considered as a relevant downstream market for the QCLNG Export Pipeline.

There are several other LNG export proposals currently under investigation in the Gladstone region. If these proposed LNG projects were to proceed as currently proposed, further dedicated pipeline connections from the CSG fields of the Surat and Bowen Basins to Gladstone, Rockhampton and Wide Bay would be constructed.

The current levels of gas consumption in the relevant downstream markets are as follows:

- Gladstone – 24 PJ/a
- Rockhampton – 1.6 PJ/a
- Wide Bay – approximately 0.3PJ/a

On the basis of proposed new industrial loads and expansion of existing mineral processing sites, demand at Gladstone is expected to grow to around 64 PJ/a by 2014. After this date, there is an apparent levelling out of demand at Gladstone. However, this is an artefact of the planning horizon for large industrial projects of this type, rather than an indication that the Gladstone market will have reached any form of natural size limit. There may well be further growth in gas demand at Gladstone post 2015 but no emergent demand has been included in the projections because any such growth would, at this stage, be purely speculative.

The small retail loads in Rockhampton and Wide Bay are expected to grow in line with regional economic and demographic growth, but will remain small in absolute terms.

Wholesale delivered prices into Gladstone and Rockhampton are presently estimated to be in the range A$3.50 to A$4.50/GJ, including transport cost on the QGP of A$0.80 to A$1.00/GJ, depending on customer load factor. The cost of gas to retail customers is considerably higher, because as well as the cost of the gas ex field and transmission pipeline costs, customers also pay for low-pressure distribution and retail charges.

The chapter includes discussion of the implications of government policies for future gas demand. The Carbon Pollution Reduction Scheme (CPRS) is expected to be directionally very positive for gas demand, because it tilts the economics of electricity generation and large-scale industrial heating away from coal and toward less emission-intensive energy sources, including gas. CPRS will also result in higher sustainable gas prices because of improved competitiveness with coal on a carbon-

inclusive basis. CPRS is estimated to increase the wholesale price of gas by around A$1.00/GJ for each A$30/t CO_2e carbon price. The expanded Renewable Energy Target (RET), on the other hand, will tend to suppress consumption of gas for power generation, but will drive a need for additional open-cycle gas-fired peaking plant as back-up to unreliable wind generation. This will not greatly increase gas consumption, but will require greater flexibility in gas supply and gas storage, particularly in South Australia and Victoria. The RET scheme is unlikely to have a great effect on gas demand in the Gladstone region because the only currently proposed gas-fired generators are the proposed QAL and Comalco cogeneration facilities, and there is a lack of good quality wind generation sites in Central Queensland.

The Queensland Government recently considered introduction of a "domestic market obligation" which could have required LNG project proponents to set aside up to 20% of their CSG reserves for local domestic purposes. On 14 November 2009 the Queensland Government announced that, rather than impose a domestic market obligation on LNG proponents, it would move to set aside areas prospective for CSG that could be released to meet future domestic gas market requirements.

The latter part of the chapter sets out the results of modelling two LNG development scenarios: a "Project Case" involving development of the first two LNG trains proposed by QGC (and a sensitivity case assessing the impacts of a third train); and an "Industry Case" that includes a further 4 LNG trains built by other proponents and involving two additional LNG export pipelines.

All three scenarios show that anticipated gas demand in the downstream markets is substantially satisfied throughout the modelling period (to 2030) without utilisation of the QCLNG Export Pipeline for carriage of gas to domestic markets.

Importantly, the modelling results show that all gas delivered into the Gladstone market is transported via the existing Queensland Gas Pipeline (QGP), rather than the QCLNG Export pipeline. No gas is delivered to the Gladstone domestic market via the QCLNG Export Pipeline—even on a short term basis during the ramp-up to full LNG production—because QGP provides a more economical transport pathway.

Modelling of gas prices under the three scenarios shows some softening of real prices in the short term, as a result of excess ramp gas being available in the market. Prices then rise from a low of around A$4.50/GJ delivered at Gladstone prior to commissioning of the LNG facilities to around A$5.30 (real, 2009) by 2030 in the "Project Case", and around A$5.75/GJ in the "Industry Case".

In this section, we first consider the question of what are the relevant downstream markets that could be serviced by gas carried in the QCLNG pipeline. We also discuss how state and federal government policies potentially affecting gas demand have been taken into account in developing the demand forecasts.

For each of these markets, we discuss the major existing and prospective gas loads that constitute the local demand for natural gas; the nature of their current gas supply arrangements and load characteristics; and assess the overall demand for gas in the market location based on the requirements of the individual loads. A breakdown of demand by category of user (power generation; industrial use including co-generation; commercial and residential) is provided.

The next part of this section discusses current gas prices and price structures for different categories of gas customer in the region.

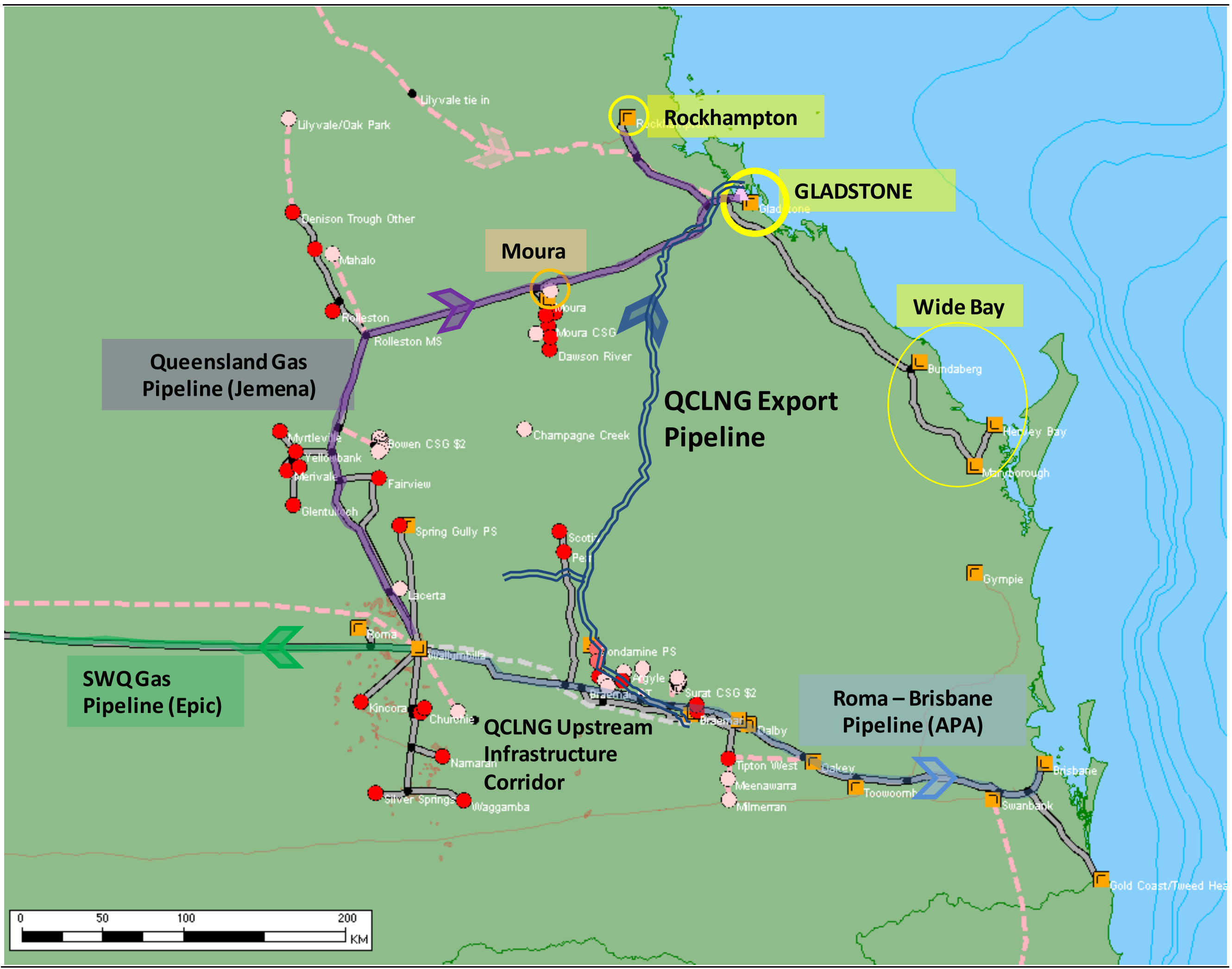
The final part of this section presents the results of modelling two future scenarios with different levels of export LNG development, using our *GMG Australia* gas market model. The modelling results presented include gas consumption and wholesale delivered gas prices on an annual basis from 2009 to 2030.

2.1 Relevant downstream markets

Figure 2 shows the location of the QCLNG Export Pipeline and associated Upstream Infrastructure Corridor and Lateral Pipeline relative to existing gas transmission pipelines, gas fields and gas markets. The industrial city of **Gladstone** is the main downstream market potentially served by the QCLNG Export Pipeline. Gas delivered to Gladstone via the QCLNG pipeline could be transferred to the Queensland Gas Pipeline system (operated by Jemena) for carriage to **Rockhampton**, or to the Gladstone – Wide Bay Pipeline (operated by Origin Energy) for carriage to the **Wide Bay** area (Bundaberg, Maryborough and Hervey Bay).

Also shown in Figure 2 is the southern part of the proposed Central Queensland Gas Pipeline which would provide transportation for gas from Moranbah in the northern Bowen Basin to markets in Gladstone and the surrounding regions.

Figure 2 **Downstream markets for the QCLNG Export Pipeline**



Source: ACIL Tasman compilation; map base from GMG Australia model

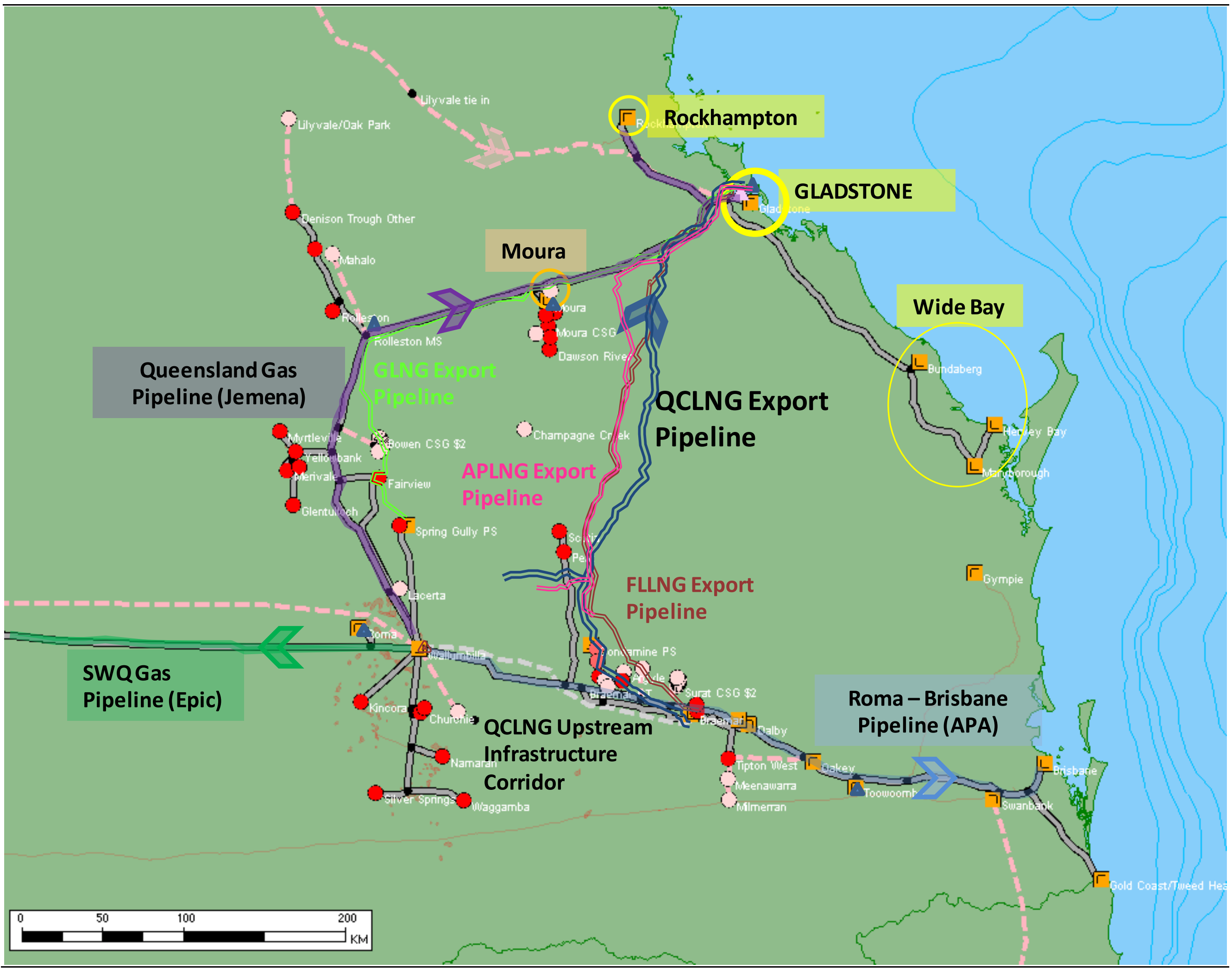
The only other existing gas market that could potentially be serviced from the QCLNG pipeline is at **Moura**. However access to the Moura market would require construction of a pipeline lateral of approximately 75 km length, which is unlikely to be economically viable given that the only significant gas customer at Moura (Queensland Nitrates Pty Ltd – a joint venture involving Dyno Nobel Asia Pacific and Wesfarmers CSBP) has a relatively small gas requirement of around 3 PJ/a and is currently supplied from the adjacent Moura – Dawson River CSG fields. Moura also has existing access to gas supplied via the Queensland Gas Pipeline (Jemena). For this reason, Moura is not further considered as a relevant downstream market for the QCLNG Export Pipeline.

2.1.1 Other CSG LNG Export proposals

As discussed in Chapter 3 of this report, there are several other proposals for establishment of LNG facilities at Gladstone based on CSG produced from the Bowen and Surat Basins of central and southern Queensland, and transported to Gladstone by pipelines for liquefaction. Figure 3 shows the notional routes of export gas pipelines from the CSG production fields to proposed LNG plants near Gladstone for three other projects that have lodged Initial Advice Statements and/or Environmental Impact documentation: the Fisherman's Landing LNG Project of Arrow Energy/LNG Limited (FLLNG); Gladstone LNG of Santos/Petronas (GLNG); and Australia Pacific LNG of Origin Energy/ConocoPhillips (APLNG). While the Shell Australia LNG project has submitted an IAS, no pipeline route has yet been indicated.

If one or more of these proposed LNG projects were to proceed as currently proposed, a further pipeline connection or connections from the CSG fields of the Surat and Bowen Basins to Gladstone, Rockhampton and Wide Bay would be constructed.

Figure 3 **Proposed pipeline infrastructure to support LNG facilities in Gladstone**



Data source: *ACIL Tasman compilation; map base from GMG Australia model. Information on proposed locations of export gas pipelines is approximate, and has been derived from Initial Advice Statements or Environmental Impact Study documents prepared and published by the proponents*

2.1.2 Current gas consumption in the relevant downstream markets

The current levels of gas consumption in the relevant downstream markets are as follows:

- Gladstone – 24 PJ/a
- Rockhampton – 1.6 PJ/a
- Wide Bay – approximately 0.3PJ/a

2.2 Summary of demand

The current and projected gas loads in the relevant downstream markets in Gladstone, Rockhampton and Wide Bay are summarised in Table 1. The projections show how demand is split between the three regional sub-markets. Table 1 also provides a split of the total regional gas demand by customer category: industrial, cogeneration and retail small customers (including residential, commercial and small industrial users serviced by the Envestra distribution business in Gladstone and Rockhampton, and by Origin in Wide Bay). There is no existing or anticipated gas-fired power generation other than through co-generation in the relevant markets.

Table 1 **Summary of current and projected demand in relevant downstream markets**

	2009	2015	2020	2025	2030
Gladstone	23.6	64.2	64.8	65.0	65.0
Rockhampton	1.6	1.6	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
Industrial	25.7	38.6	39.2	39.3	39.3
Cogeneration (Gladstone)	0.0	27.6	27.6	27.6	27.6
Retail small customers	0.6	0.7	0.8	0.9	1.0

Demand in PJ per year

Data source: ACIL Tasman GMG Australia model

2.3 Demand by market location

2.3.1 Gladstone

Gladstone is a substantial gas market centre with a number of large industrial users as well as a small reticulation market serving mainly small industrial customers. Table 2 provides a breakdown of current and projected demand in Gladstone by customer.

Table 2 **Current and projected demand in Gladstone**

	2009	2015	2020	2025	2030
Boyne Is. Smelter	1.4	1.4	1.4	1.4	1.4
Comalco Yarwun Refinery Stage 1	4.0	4.0	4.0	4.0	4.0
CAR Stage 2 Calcining	0.0	7.2	7.2	7.2	7.2
CAR Stage 2 Cogen	0.0	15.6	15.6	15.6	15.6
Gladstone Retail Market	0.2	0.2	0.3	0.2	0.3
Orica - NaCN cholalkali	1.5	1.5	1.5	1.5	1.5
Orica NH4NO3 expansion	5.0	5.0	5.0	5.0	5.0
QAL Alumina Plant	11.6	12.3	13.0	12.9	13.0
QAL - Alumina Plant Expansion	0.0	5.0	5.0	5.0	5.0
QAL Cogen	0.0	12.0	12.0	12.0	12.0
TOTAL	23.6	64.2	65.0	64.8	65.0

Demand in PJ per year

Data source: ACIL Tasman GMG Australia model

The Gladstone demand profile

It is important to note that the apparent levelling out of demand at Gladstone after 2015 is a result of the fact that almost all demand growth in this market relates to large-scale industrial loads, and there are no such new loads currently proposed to come on line post 2015. This is an artefact of the planning horizon for large industrial projects of this type, rather than an indication that the Gladstone market will have reached any form of natural size limit. While there may well be further growth in gas demand at Gladstone post 2015, no such emergent demand has been included in the projections because any such growth would, at this stage, be purely speculative.

Queensland Alumina Limited (QAL)

The Gladstone alumina refinery operated by Queensland Alumina Limited is the largest in the world, with a maximum annual rated capacity of 3.65 million tonnes. Bauxite from the Weipa mine on Cape York Peninsula is processed in the refinery to produce alumina, which is then shipped to JV smelters in Australia (including the nearby Boyne Island smelter) and overseas. Refinery operations commenced in 1967. The site has seen a series of expansion programs resulting in a six-fold increase in capacity from the initial 600,000 tpa plant.

QAL uses energy primarily for process steam-raising and for calcining (the process in which aluminium hydrate is converted to aluminium oxide). Current energy requirements are:

- About 1.5 million tonnes of coal per year (equivalent to about 34 PJ/a) of coal for steam-raising
- 11 to 13 PJ/a of natural gas for calcining
- 90 MW of grid electricity.

Until recently, the QAL plant used about 13 PJ/a of natural gas for calcining. In late 2003 a program to replace nine "old technology" rotary kilns with three state-of-art stationary calciners was completed. This was anticipated to reduce gas demand by around 25% – from 13 PJ/a to about 10 PJ/a. This reduction has been offset somewhat by overall increases in plant output as a result of ongoing productivity improvements and de-bottlenecking. As a result current gas consumption is understood to be around 12 PJ/a. QAL indicate that there may be some scope for rebound toward the 13 PJ/a level depending on alumina production levels. However the current assumption is that total demand from the existing operations will remain around 12 PJ/a and can be accommodated under the Origin contract until expiry.

QAL has advised that there is potential for a major plant expansion that could require an additional 16 PJ/a. This would comprise of 11 PJ/a for co-generation plus 5 PJ/a for increased calcining capacity. No indication of timing has been provided by QAL. This additional gas requirement could emerge from 2012 onwards.[1]

QAL was initially supplied with its full gas requirements under contract from conventional gas fields in the Denison Trough (Origin). The initial contract ran until late 2006. In December 2003, QAL announced signing of a new gas supply agreement that will see Origin supply between some 11 PJ/a to QAL over a period of 15 years, commencing 1 November 2006. The main source of supply is said to be Central Queensland CSG – presumably from Origin's interests in the Fairview and Spring Gully fields although it is understood that there is no restriction on the source of gas. QAL also has some flexibility to purchase gas from other suppliers above take-or-pay levels as specified under the Origin supply agreement.

Yarwun Alumina Refinery (YAR)

The Yarwun Alumina Refinery (YAR, formerly known as CAR – Comalco Alumina Refinery) is situated in the Yarwun area, 10km north-west of Gladstone. Stage 1 of YAR involved a 1.4 mtpa alumina refinery at a cost of US$750m. Construction commenced in 2002, with the plant fully operational by early 2005.

The project includes:

- the refinery process site containing production facilities including a steam generation plant
- the bauxite residue storage area, 10 km west of the refinery site
- the port facility, materials handling and transportation, and associated stockpile areas.

YAR's energy use is primarily for process steam-raising and for calcining (the process in which aluminium hydrate is converted to aluminium oxide). The energy requirements for Stage 1 are:

- About 23 PJ/a of coal for steam-raising[2]
- 4 PJ/a of natural gas for calcining
- 63 MW of grid electricity.

[1] In August 2006, QAL applied for a generation license for a 122 MW cogeneration plant.

[2] While the Stage 1 steam plant has been designed to operate on coal, it could be converted to run on gas (most likely through a retrofitted cogeneration plant) if adequate low-priced gas supply becomes available

Gas supply for stage 1 calcining requirements was provided for under a contract with Energex based on its CSG portfolio (most likely Fairview gas contracted originally from Tipperary, now Santos). The contract provides for delivery of 4 PJ/a commencing Q4 2004 for a period of 10 years. We understand that QAL was paying around A$3.50/GJ (delivered basis) for calcining gas as at 2004.

Rio Tinto has commenced a US$2.2 billion expansion, increasing alumina capacity to 3.4 mtpa although during 2009 the expansion project was slowed down in light of weak alumina demand as a result of the Global Financial Crisis. As at mid-2009 the expansion was said to be around 30% complete.

As part of the expansion, a 160 MW gas cogeneration plant will be added, providing the plant with its entire electricity requirement (approximately 90 MW after expansion) and meeting a portion of its steam needs. Gas requirements for the cogeneration plant and additional calcining volumes total 22.8 PJ/a. Coal will continue to be used to supplement steam requirements for process heat.

CSG will be supplied by Origin Energy ex Fairview/Spring Gully, with a major looping of Jemena's Queensland Gas Pipeline (QGP) being also required, increasing throughput capacity to 49 PJ/a.

Orica

The Orica site at Yarwun Industrial Estate, 10 km north of Gladstone, incorporates the following chemical plants:

- Sodium cyanide plant (80,000 tpa following progrssive uprating of original 20,000 tpa plant)
- Chloralkali production (9,500 tpa as caustic soda)
- Ammonium nitrate (capacity 580,000 tpa). It presently uses some 100,000tpa of ammonia transported from Incitec's Gibson Island (Brisbane) plant, complemented by imports.

Ammonium nitrate production capacity was increased by approximately 25,000 tpa to 300,000 tpa in 2005, and further increased to 580,000 tpa in 2006. It is now said to be the largest industrial grade ammonium nitrate complex in the world (Mossop, 2008).

The plant currently relies on a mix of local and overseas imports of ammonia, rather than local manufacture of ammonia. At the current production scale, local production would require around 12.6 PJ/a of natural gas.

ACIL Tasman understands current gas requirements as follows:

- Sodium cyanide plant (80,000 tpa)

- Natural gas 36 GJ per tonne product, therefore about 2.9 PJ/a at current capacity
- Electricity 0.67 MWh per tonne product
- Chloralkali plant (9,500 tpa plus expansion)
  - Natural gas 30 GJ per tonne product, therefore about 0.3PJ/a
  - Electricity 3 MWh per tonne product.

Current gas consumption is around 1.5 PJ/a supplied under a contract from Fairview. The contract (originally written with Tipperary Oil and Gas Australia) commenced on June 26, 2006, and provides that Orica will purchase a minimum of 3.2 TJ/day and a maximum of 5 TJ/day. The term of the contract is for 10 years. Santos now supplies this contract after its acquisition of Tipperary's Fairview assets in 2005.

Boyne Smelters Ltd

The Boyne Island aluminium smelter began operation in 1982 and, following the commissioning of a US$1 billion expansion in 1997 and subsequent upgrades, has a production capacity of 557,000 tpa[3]. It is the largest smelter in Australia and presently the fourth largest in the world. The smelter operates three reduction lines, a metal casting house, an anode production plant and ancillary facilities.

Consideration has been given to an expansion that would see overall production capacity at BSL increase to 708,000tpa (80 extra cells for each of potlines 1 and 2, plus 48 extra cells for potline 3), but according to Gladstone Area Promotion & Development, the project has been postponed indefinitely.

Power for the smelter is supplied by Gladstone Power Station (GPS) and from the Queensland electricity grid. GPS was purchased from the Queensland Electricity Commission in 1994 by a group of companies, including some of the Boyne Smelters Limited participants, in order to enhance electricity supply security. The 1,680 MW capacity station supplies over 800 MW of power to the Boyne Island smelter each year. The balance is sold through the National Electricity Market.

BSL uses natural gas for anode production and in the carbon plant. Current gas requirements are understood to be about 1.4 PJ/a. Fuel alternatives to natural gas are liquid fuel or LPG.

[3] As at 31 December 2008: (Rio Tinto, 2009).

Gas is contracted through Energex (now owned by AGL Energy after the acquisition of Sun Retail in 2006). Contract commenced in September 2001 for volumes up to 1.5 PJ/a, term unknown.

Stuart Oil Shale (on hold)

The Stuart Oil Shale project which is now in care and maintenance was also a gas user taking small volumes (<0.5 PJ/a) for ore drying and plant start-up. Plagued by plant problems, it is unclear whether this load will re-emerge in the future. Southern Pacific Petroleum (SPP) the developer of the Stuart project, was placed into receivership by its secured creditor Sandefer Capital Partners, in December 2003. The project is now operated by Queensland Energy Resources (QER).

If QER proceed with plans for a staged development of shale oil production at Stuart, there may be opportunities to resume gas supply to the site. However, the project's total demand for gas is likely to remain low and limited to ore-drying and start-up requirements. Production of shale oil is currently subject to a Queensland government moratorium which adds to the uncertainty regarding timing of any resumption of activities at Stuart. Accordingly, we have not included any demand associated with the Stuart project in our modelling assumptions.

2.3.2 Rockhampton

Rockhampton is a relatively small gas market with a single large industrial user and a small reticulation market serving small industrial, commercial and residential customers.

Queensland Magnesia (QMAG)

The sole major industrial gas user in Rockhampton at present is QMAG.

Queensland Magnesia (QMAG) based at Parkhurst, Rockhampton in Central Queensland is one of the world's largest magnesite, calcined magnesia and refractory magnesia operations.

QMAG was established as a joint venture in 1987 to mine and process magnesite from the Kunwarara magnesite deposit. Since 1997 it has been a wholly owned subsidiary of Australian Magnesium Corporation Limited. Construction of the mine and processing facilities began in 1989 and commercial production of beneficiated magnesite and magnesia products commenced in 1991.

Approximately 3 million tonnes of ore is mined each year at Kunwarara to yield some 450,000 tonnes annually of high grade beneficiated magnesite - a simple first stage washing, sorting and screening process. Parkhurst processes the beneficiated magnesite ($MgCO_3$) into calcined magnesia, deadburned magnesia and electrofused magnesia.

These products are all magnesium oxides (MgO) but each have different physical properties. The Parkhurst plant has the capacity to produce approximately 200,000 tpa of calcined magnesia in two multiple-hearth natural gas fired furnaces. These operate at approximately 1000°C. This calcination or heating process decomposes the magnesite into MgO and carbon dioxide (CO_2).

The calcined magnesia is predominantly used as a feedstock for the production of deadburned and electrofused magnesia. Deadburned magnesia is produced by refiring the calcined magnesia to a temperature of 2,000°C in vertical shaft kilns. The three gas fired kilns of this type at Parkhurst have a total annual capacity of some 120,000 tpa.

To produce electrofused magnesia, three electric arc furnaces are used to fuse or melt calcined magnesia at approximately 3,000°C. The electrofusing furnaces have an annual capacity of up to 30,000 tonnes.

Current gas requirements are 1.5 PJ/a with the site also using around 120 GWh/a of electricity.

QMAG has in the past investigated plans to double the capacity of the current Parkhurst operations. Consideration has also been given to locating a new plant at Kunwarara due to issues transporting ore to North Rockhampton. The expansion would result in doubling of current gas requirements (from 1.5 PJ/a to 3.0 PJ/a). However, at this point in time it is unclear whether the expansion will occur, and if so when.

Stanwell power (not proceeding)

Stanwell Corporation was investigating the feasibility of constructing a gas-fired peaking station near its existing Stanwell Power Station in 2006. As a result of the station's low expected capacity factor (<5%) the cost of supplying gas into the station was believed to be around A$7-A$10/GJ. Stanwell has since decided not to proceed with the project.

2.3.3 Reticulated demand

Envestra's Northern distribution network supplies small customers in both Gladstone and Rockhampton. Reticulated gas demand is relatively small however, as shown in Table 3.

Table 3 **Actual and forecast reticulated demand (TJ/a)**

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Domestic	24	23	23	23	23	23	23
Commercial	161	160	166	171	174	178	181
Large users	185	184	189	194	197	201	204
Total	370	367	378	388	394	402	408

Note: Throughput volumes for large users was taken from previous forecasts completed in November 2005
Data source: Update demand forecasts for Envestra, MMA, April 2006

Origin Energy is the primary retailer in the Envestra networks although the market is now exposed to competition as full retail contestability for all users commenced in July 2007.

2.3.4 Wide Bay region

The Wide Bay region—which includes Bundaberg, Maryborough and Hervey Bay— is supplied with gas delivered via the Wide Bay Pipeline which runs from Gladstone south to Maryborough, a distance of some 309km. The pipeline has a low capacity, being only 100mm in diameter.

Neither the Wide Bay Pipeline nor the gas distribution systems in the Wide Bay region are covered pipelines under the National Gas Law. As a result, there is little public domain information regarding gas demand serviced by the pipeline. However, we understand that the market comprises entirely retail customers (residential, commercial and small industrial) and that the total gas demand in the region is small—around 0.3PJ/a.

2.4 Gas prices in the relevant markets

Wholesale gas prices delivered into the relevant markets include two components: the cost of gas and the cost of pipeline transmission. Final delivered prices are contract-specific and are not publicly available. However, based on limited public domain information regarding existing gas supply contracts, we estimate that wholesale delivered prices into Gladstone and Rockhampton are presently in the range A$3.50 to A$4.50/GJ, including transport cost on the QGP of A$0.80 to A$1.00/GJ depending on customer load factor.

The cost of gas to retail customers is considerably higher, because as well as the cost of the gas ex field and transmission pipeline costs, customers also pay for low-pressure distribution and retail charges. Because of the fixed service charge component in retail tariffs and volume-scaled charging for gas consumption, the average price of gas to retail customers typically reduces as the total amount of gas per billing period increases. Origin Energy is the main supplier of retail gas in Gladstone, Rockhampton and Wide Bay. According to the schedule published by Origin Energy of tariffs applicable from 1 July 2009 for retail supply in these areas, the current price of gas to typical retail customers in these areas are as shown in Table 4.

Table 4 **Current retail gas prices – Gladstone, Rockhampton, Wide Bay**

Customer Type/Size	Gladstone/ Rockhampton A$/GJ	Wide Bay A$/GJ
Residential 10 GJ/a	65.13	55.33
Residential 20 GJ/a	34.58	29.68
Commercial/Industrial 100 GJ/a	26.22	24.89
Commercial/Industrial 250 GJ/a	24.69	23.70

Note: Prices shown exclude GST

Data source: Origin Energy tariff schedule as published by Origin Energy Retail Limited

2.5 Implications of government policies for future gas demand

A number of Federal and State government policies have the potential to impact on future gas demand.

At a Federal government level, the most significant recent policy developments relate to the introduction of emission trading (Carbon Pollution Reduction Scheme) and the expanded Renewal Energy Target (RET).

Various state government policies related to energy efficiency and water conservation also have the potential to impact on future gas demand—some positively and others negatively in terms of the rate of demand growth. In the following sections we briefly review the nature of these potential impacts, and explain how they have been taken into account in the gas market modelling.

2.5.1 Carbon Pollution Reduction Scheme

Over the past two years there has been a clear shift in public and political opinion such that it is now virtually certain that Australia will adopt some form of emission trading regime that will explicitly price CO_2 emissions by 2011.

A fundamental part of the current Australian Government's climate change strategy is the proposed Carbon Pollution Reduction Scheme (CPRS). In essence the CPRS is an emissions trading scheme which places a limit (or cap) upon greenhouse gas emissions. It will require affected businesses and industry to buy a 'carbon permit' for each tonne of carbon emitted to the atmosphere, thereby providing incentives for abatement.

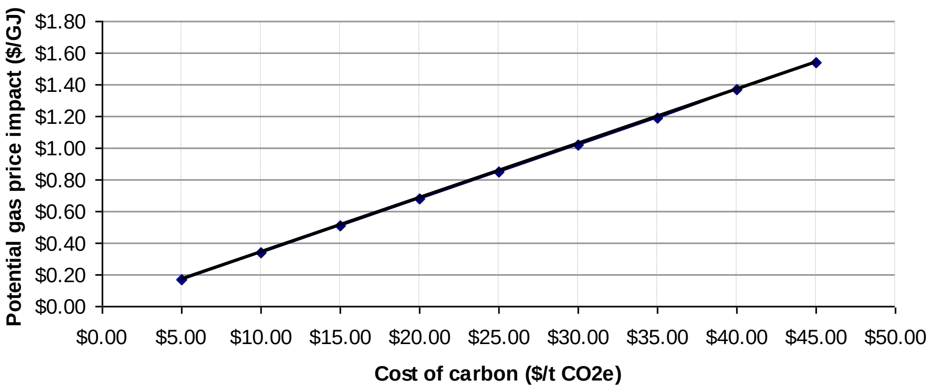
The CPRS is directionally very positive for gas demand, because it tilts the economics of electricity generation and large-scale industrial heating away from coal and toward less emission-intensive energy sources, including gas.

In May 2009 the government announced a number of changes to the design of the CPRS, including a one-year delay in the start of the scheme, to 1 July 2011, and a fixed permit cost of at A$10 per tonne of CO_2 emitted for the first year with a transition to full market trading from mid 2012. For purposes of ACIL Tasman's modelling of the national electricity market we have assumed a 5% reduction in emissions by 2020

Impact of carbon pricing on Eastern Australian gas prices

Figure 4 shows the potential impacts of the CPRS on gas price at different carbon prices.

Figure 4 **Potential gas price impacts at different costs of carbon**



Data source: ACIL Tasman analysis

These potential impacts represent the *maximum sustainable price increase* that a gas producer could extract from an electricity generator without leaving the generator in an inferior revenue position to that which it would face without the carbon price signal. In practice one might expect the value uplift to be shared between gas producer and generator so that the producer sees higher prices and the generator achieves increased levels of dispatch.

Our analysis indicates that a carbon trading scheme that delivers similar CO_2 price outcomes to Treasury CPRS 5% could result in a rise in real wholesale gas prices of around A$0.50/GJ initially (from 2011), to A$1.09/GJ by 2020 and A$2.07/GJ by 2030. For modelling purposes, we have incorporated a corresponding increase in producer minimum price expectations, which in turn will flow through into modelled price outcomes.

2.5.2 Renewable Energy Target

The expanded Renewable Energy Target (RET) requires liable electricity retailers to source 20% of the electricity that they sell to consumers from renewable sources, by 2020. The scheme is directionally unfavourable for gas demand because it will result in more power generation in the National Electricity Market coming from renewable sources (in particular, wind generation with possible contributions from geothermal), at the expense of opportunities for base and intermediate load gas-fired power generation using Combined Cycle Gas Turbine technology. This suppression of demand for gas in power generation is incorporated into our demand assumptions in the GMG Australia gas market modelling.

It is worth noting, however, that because wind is an intermittent generation source there will be a need for gas-fired generation as back-up when wind output is low. While the total volumes of gas consumed in providing this back-up role will be relatively small, the high rate of fuel consumption when the gas-fired peaking plant is called on to run means that there will be a strong increase in demand for access to pipeline capacity in the regions where the wind generators and back-up gas fired peaking plant locates—which will be mainly in Victoria and South Australia.

The lack of good quality sites for wind generation in Central Queensland means that the RET scheme is unlikely to have a significant impact on gas demand in the downstream markets relevant to the QCLNG Export Pipeline.

2.5.3 Queensland Domestic Gas Market Obligation

In September 2009 the Queensland Government released a consultation paper on Domestic Gas Market Security of Supply. In that consultation paper the government noted that it:

> "... must be sure there will be sufficient supply of affordable gas available to meet future electricity generation needs and to support the ongoing development of Queensland's industrial sector.
>
> Current Queensland gas market conditions (contract availability and pricing) are being influenced by LNG proponents' requirements to satisfy their Boards, bankers and LNG customers that they have security over sufficient gas supply to underwrite proposed LNG investments.
>
> Queensland industrial gas customers are reporting increasing difficulty obtaining medium to long-term gas contracts"[4]

[4] Queensland Government, 2009: "Consultation Paper. Domestic Gas Market Security of Supply", p.2.

To address this perceived constraint on domestic gas supply, the Queensland Government canvassed two options for providing additional certainty about the availability of gas to the domestic market, and its price, in the presence of the proposed LNG developments:

- Option 1 – application of a reservation policy requiring a percentage of gas production to be supplied to the domestic market.
- Option 2 – development of a reserve of potential gas-producing land that could be released as required to ensure adequate domestic supply. Depending on supply constraints identified in regular market assessments, this land may be conditioned such that it is only available to the domestic market.

The first option was a similar model to the domestic gas reservation policy introduced by the Western Australian government in 2007, which requires proponents of new LNG export projects to make available to the local domestic market an amount of gas equal to 15% of the reserves dedicated to the export LNG project.

An obligation to reserve up to 20% of reserves for domestic use would have had significant implications for the QCLNG Project in terms of potential delay and increased risk associated with the process of establishing sufficient reserves to allow the project to proceed. The policy could in effect have required the proponents to prove up an additional 20% of reserves prior to any final investment decision. Each LNG Train will need secure access to between 4,500 and 5,000 PJ of CSG reserves. With a 20% reservation requirement, the minimum reserves backing would have increased to 5,400 PJ per train. The impact of a reserves reservation requirement would have been especially significant for the proposed third LNG train: at present QGC does not have access to sufficient reserves to supply a full third train and will need to identify more reserves before a decision to proceed with Train 3 can be made. A domestic market obligation would have increased the risk of Train 3 being delayed or proving to be non-viable.

On 14 November 2009 the Queensland Government announced that, rather than imposing a domestic reservation requirement on LNG proponents, it would set aside areas of land prospective for CSG that could, if required, be released for exploration and development of resources for future domestic gas supply. This decision avoids the increase in risk for LNG proponents alluded to above.

2.6 Modelling future gas consumption and prices

This section presents results of modelling of gas supply to the relevant markets, and wholesale gas prices delivered to the relevant market locations.

Two modelling scenarios have been developed, based on the assumptions used in ACIL Tasman's *Gas Market Review & Outlook 2009*.

The model used for this analysis is ACIL Tasman's proprietary GMG Australia (*GasMark*®) model, details of which are provided in Appendix C.

2.6.1 Modelling scenarios

The two modelling scenarios are:

- A **"Project Case"** that assumes a nominal 4 mtpa LNG train that commences commissioning late 2013 and operates at full capacity from 2014, with the second LNG train (also nominal capacity 4 mtpa) that commences commissioning in 2014 and operates at full capacity from 2015. This represents the "Base Case" for the Queensland Curtis LNG Project. A sensitivity scenario was also run incorporating a third 4 mtpa LNG train reaching full production in 2016. All other assumptions for the 3-train sensitivity were as for the "Project Case"
- An **"Industry Case"** that adopts the same assumptions as the 3-train sensitivity "Project Case" except for inclusion of four additional LNG trains. We have assumed for this case a separate LNG facility with two trains each of 1.3 mtpa capacity located at Fisherman's Landing, with production commencing late 2013. We have assumed another separate LNG facility with two trains each of 4 mtpa nominal capacity located on Curtis Island, with production from the first LNG train commencing late 2014 and from the second LNG train in late 2016. We have assumed that both of these LNG facilities are independently serviced by dedicated transmission pipelines from the CSG production fields to the liquefaction facilities. Overall CSG production capability is scaled up accordingly to accommodate the additional LNG production capacity.

2.6.2 Modelling assumptions

Both scenarios take as their starting point the base case assumptions used in ACIL Tasman's *Gas Market Review & Outlook 2009*, with certain modifications as noted below.

Both scenarios incorporate what we consider to be reasonable mid-line assumptions in relation to supply and demand side factors affecting the outlook for Eastern Australian domestic gas markets. Key considerations for each case include:

- the future contribution of Coal Seam Gas (CSG) in Queensland and New South Wales to the overall supply of gas for domestic markets
- LNG developments based on Coal Seam Gas (CSG) in Central Queensland (Surat and Bowen Basins)

- anticipated commencement of a National Emission Trading Scheme by 2011 and the consequences for demand for gas in power generation and for gas price tolerances. The carbon price assumptions adopted are consistent with Treasury modelling of the "CRPS 5%" case (Treasury Department, 2008)
- reduction in gas demand for electricity generation in the NEM to reflect reduced requirements for conventional generation because of increased renewable energy contribution under the 20% Renewable Energy Target
- a comprehensive representation of existing and committed transmission pipeline capacity as well assumed capacity expansions to meet anticipated market growth.

The assumptions common to both scenarios include:

- Current mid-range estimates for future supply
  - from existing fields, based on current production capacity and known reserves
  - from new discoveries based on reasonable assessment of discovery rates and output profiles when brought into production
  - minimum producer price assumptions based on expectation of increasing costs over time to discover new gas reserves and bring new production on line, taking into account recent price trends and expectations
- With regard to coal seam gas (CSG) in Queensland, the "Project Case" assumes continued expansion of production and reserves base with costs increasing over time as more expensive, less productive deposits are accessed. Total production capability from Queensland CSG reaches around 1,240 PJ/a, across a range of price points, over the next 10 years. The "Industry Case" scenario assumes commensurately higher levels of Queensland CSG reserves and production capacity, as discussed on page 29.
- With regard to coal seam gas (CSG) in New South Wales assumes current exploration succeeds in establishing substantial production capacity, again with costs increasing over time as more expensive, less productive deposits are accessed. Total production capability from NSW CSG reaches around 400 PJ/a across a range of price points over the next 20 years
- Bass Strait conventional gas
  - production and resource backing for existing fields reflects installed production capacity and known gas reserves (proven & probable, "2P")
  - assumes significant new reserves are discovered and production capacity established as a result of on-going exploration in Otway Basin (up to 200 PJ/a additional production), Bass Basin (up to 65 PJ/a additional production) and Gippsland Basins (up to 475 PJ/a additional production).

- On the demand side the following is assumed:
  - Retail (commercial and residential) demand growth driven by demographic and economic (GSP) trends
  - Industrial growth driven by economic (GSP) trends in the small industrial sector; large industrial based on individual existing and new projects included in data base
  - Gas demand for power generation based on calculated fuel demand associated with dispatch of individual existing and new entrant plant, as derived from ACIL Tasman electricity market modelling.
    - … Gas for power generation requirements take into account increased demand for gas-fired power generation as a result of introduction of Carbon Pollution Reduction Scheme, and government emission reduction and renewable power generation targets.

Tariff assumptions for transmission pipelines reflect current reference tariffs for covered (regulated) pipelines, and current rack rate posted tariffs for non-covered (unregulated) pipelines. We generally assume that regulated tariff rates will be rolled-over, without discontinuity, at any subsequent review event.

Modifications to the GMRO Base Case Assumptions

The following modifications have been made to the assumptions used in the base case modelling for the *Gas Market Review & Outlook 2009* multi-client study:

"Project Case"

Assumptions for the **Project Case** are identical to the GMRO Base Case except in relation to:

- the size and timing of export LNG development at Gladstone, and
- the transmission pipeline configuration to transport gas from the CSG fields of the Surat and Bowen Basins to the Gladstone LNG facilities.

The GMRO Base Case included a notional 2-train LNG development on Curtis Island, Gladstone, with the first LNG train (4 mtpa capacity) in 2014 and the second train (also 4 mtpa capacity) in 2018. The **Project Case** adopts somewhat different assumptions reflecting the intentions of BG/QGC regarding the size and timing of the Queensland Curtis Island LNG Project. Accordingly, this case assumes a nominal 4 mtpa LNG train that commences commissioning late 2013 and operates at full capacity from 2014, with the second LNG train (also nominal capacity 4 mtpa) that commences commissioning in 2014 and operates at full capacity from 2015.

The GMRO Base Case did not include dedicated LNG pipeline facilities. Instead, it assumed that all CSG fields could access the existing Queensland

Gas Pipeline (QGP) operated by Jemena, and that the QGP had no capacity constraints so that all LNG feed requirements could be transported to Gladstone via the QGP, at prevailing tariff rates. A short pipeline lateral from the QGP to the Curtis Island LNG precinct was also assumed.

For the **Project Case** we have assumed that dedicated LNG pipeline facilities are constructed, following a similar route to that shown in Figure 2 for the proposed QCLNG Pipeline. The capacity of the QCLNG pipeline is assumed to be sufficient to accommodate the two-train LNG development, in accordance with the guidance provided by QGC, with potential for expansion by means of additional compression to accommodate a third train (this is investigated in the **"Project Case 3-train Sensitivity"**). We have assumed that the QCLNG pipeline connects directly to the Curtis Island LNG precinct, with an interconnection to the QGP (at the Gladstone City Gate) provided to allow for short-term use of the QCLNG Pipeline for transport of third party gas during the production ramp-up period. Assumed tariffs on the QCLNG pipeline are set out in section 6 of this report.

"Industry Case"

The **Industry Case** adopts the same assumptions as the **Project Case 3-train Sensitivity**, with the following exceptions:

- A separate LNG facility with two trains each of 1.3 mtpa capacity is assumed to locate at Fisherman's Landing, with production commencing late 2013. We have assumed that a dedicated LNG pipeline facility is built from the Eastern Surat Basin to the Fisherman's Landing site, with an interconnection to the QGP (at the Gladstone City Gate) provided to allow for short-term use of the export pipeline for transport of third party gas during the production ramp-up period.
- A further separate LNG facility with two trains each of 4 mtpa nominal capacity is assumed to locate on Curtis Island, with production from the first LNG train commencing late 2014, and from the second LNG train in late 2016. We have assumed that a dedicated LNG pipeline facility is built from the South West Bowen Basin and central Surat Basin to the Curtis Island site, with an interconnection to the QGP (at the Gladstone City Gate) provided to allow for short-term use of the export pipeline for transport of third party gas during the production ramp-up period.
- The corresponding gas feed requirement of 353 PJ/a in 2014 increases to 1,198 PJ/a from 2018 under the **Industry Case**.
- With regard to coal seam gas (CSG) production capacity in Queensland, further expansion of production capability and reserves base is assumed under the **Industry Case**, with more CSG available in each cost tranche of the supply curve. This assumption is consistent with the increased LNG production capacity, which will only emerge if the reserves, production

capability and cost competitiveness of the CSG supply base can support LNG development on that scale.

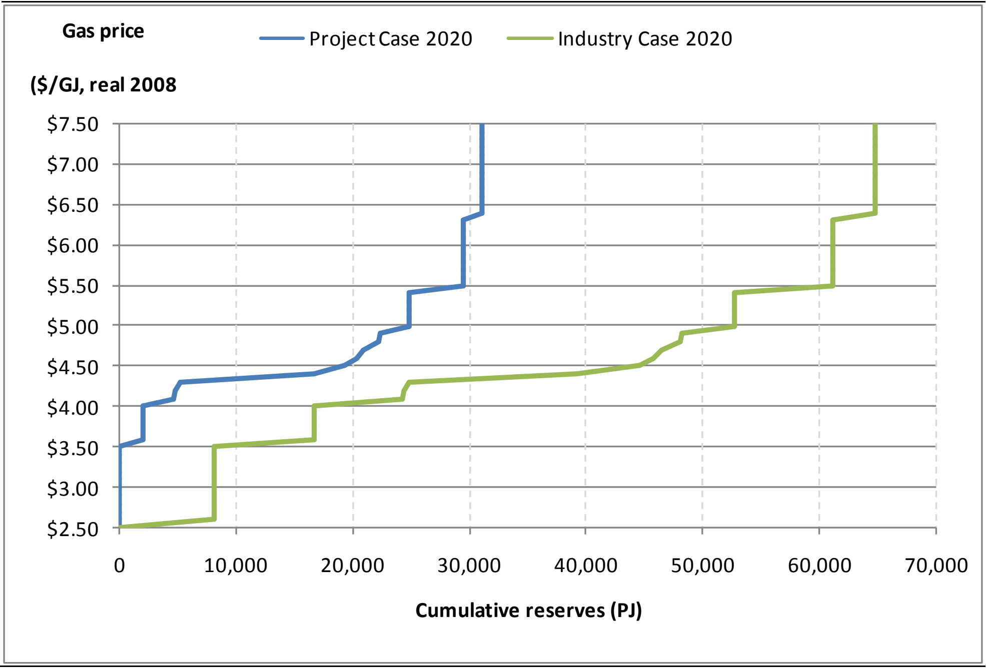
- Total production capability from Queensland CSG under the **Industry Case** reaches around 2,590 PJ/a, across a range of price points, over the next 10 years. Assuming production over a period of 25 years, the implied total recoverable resource in place is about 65,000 PJ—see Figure 5. This represents approximately double the CSG production capability compared to the **Project Case**.

The Queensland CSG production cost curves that underpin the modelling assumptions regarding CSG production capacity for the Project Case and the Industry Case are illustrated in Figure 5.

The 65,000 PJ of producible resource for the Industry Case compares to a proven and probable (2P) independently certified CSG resource in Queensland of around 17,000 PJ as at early 2009, with a proven, probable plus possible (3P) estimate of about 35,000 PJ (ACIL Tasman estimates based on public domain company reporting). **The rapid rate of reserves growth achieved over the past 5 years makes it, in our view, entirely plausible that the current 3P resource base could double within the next 10 years which would give a total resource of comparable size to that implied by the CSG supply cost curve for the Industry Case.**

No expansion of NSW CSG production is assumed beyond the levels included in the Project Case.

Figure 5 **Queensland CSG production cost curves in year 2020**



Data source: ACIL Tasman analysis

2.7 Modelling results

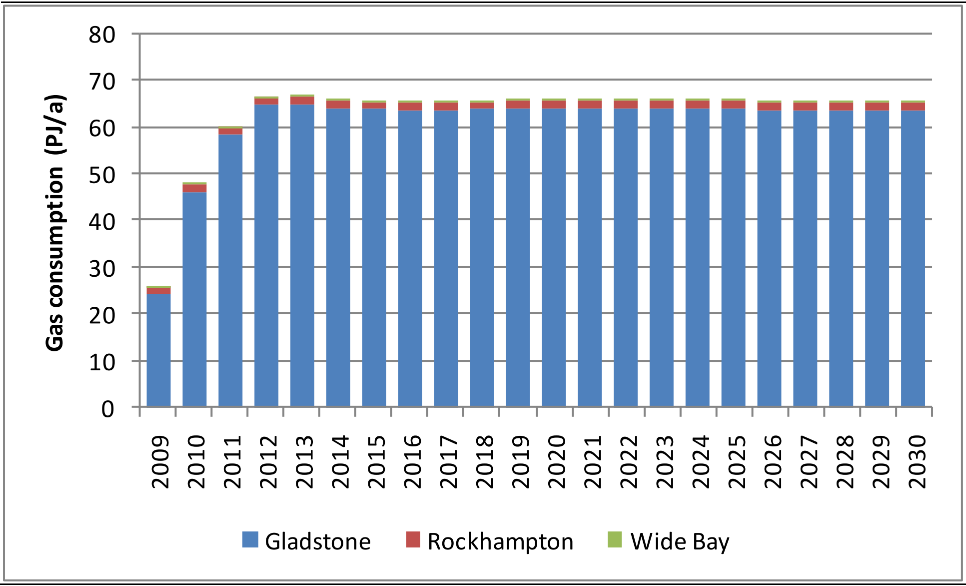
The following summarises the gas market modelling results for the two cases.

2.7.1 Gas consumption

Project Case

Figure 6 and Table 5 show the modelled gas consumption in the relevant downstream markets under the "Project Case" assumptions (two QCLNG trains). It emphasises that the overwhelming majority of the anticipated gas consumption will occur in and around Gladstone. While some gas is sold in both Rockhampton and the Wide Bay region, on current expectations Gladstone will account for more than 95% of total consumption in the region through the majority of the projection period.

Figure 6 **Modelled gas consumption—"Project Case"**



Source: ACIL Tasman GMG Australia modelling

Table 5 **Summary of modelled gas consumption, by regional market—"Project Case"**

	2009	2015	2020	2025	2030
Gladstone	24.2	64.0	64.2	64.0	63.6
Rockhampton	1.7	1.7	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
TOTAL	**26.3**	**66.0**	**66.3**	**66.2**	**65.8**

Data source: ACIL Tasman GMG Australia modelling

The gradual decline in total consumption post 2015 reflects the lack of recognised new gas loads after that time, and the gradual decline in demand as a function of increasing gas prices in the later years of the projection period. **In this regard, it is important to note the comments on page 13 with regard to the reasons for assumed lack of growth in the Gladstone market post-2015.**

Table 6 provides a more detailed breakdown of modelled gas consumption in Gladstone by customer load.

Table 6 **Modelled gas consumption in Gladstone—"Project Case"**

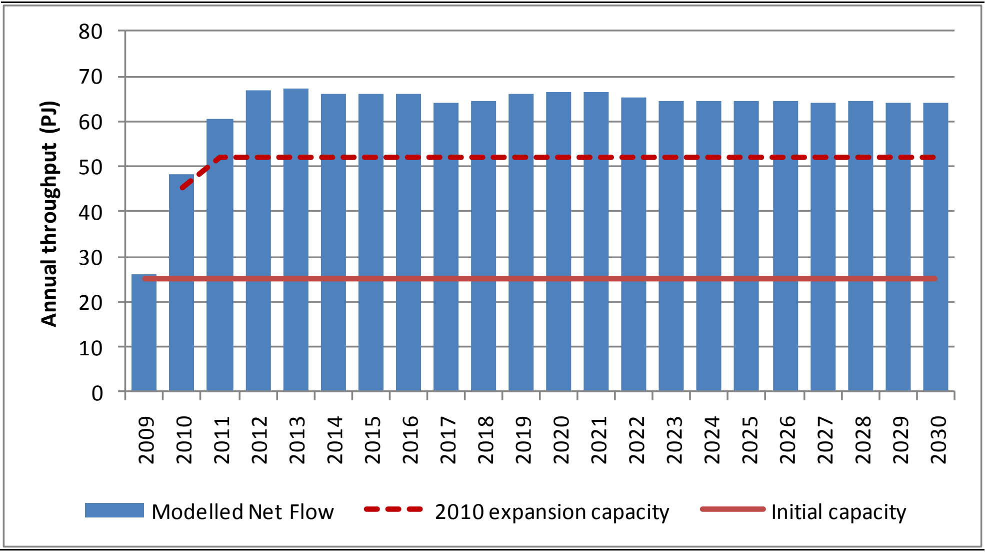
	2009	2015	2020	2025	2030
Boyne Is. Smelter	1.4	1.4	1.4	1.4	1.4
QAL Cogen	0.0	11.4	11.3	11.3	11.2
Orica - NaCN cholalkali	1.6	1.6	1.5	1.5	1.5
Orica NH4NO3 expansion	4.8	4.6	4.6	4.4	4.4
Comalco Refinery - Calcining	4.0	4.0	4.0	4.0	4.0
QAL Alumina Plant	12.3	12.8	13.2	13.2	13.0
QAL - Alumina Plant Expansion	0.0	5.2	5.1	5.1	5.0
Gladstone Base Market	0.2	0.2	0.2	0.3	0.3
CAR Stage 2 Calcining	0.0	7.2	7.2	7.2	7.2
CAR Stage 2 Cogen	0.0	15.6	15.6	15.6	15.6
TOTAL	**24.2**	**64.0**	**64.2**	**64.0**	**63.6**

Note: ACIL Tasman *GMG Australia modelling*

Transport paths to the Gladstone market

The modelling results show that all gas delivered into the Gladstone market is transported via the existing Queensland Gas Pipeline (QGP), rather than the QCLNG Export pipeline. The modelled annual gas flows on the QGP (pipeline segment from the Moura Dawson Valley branch pipeline inlet to the Rockhampton branch line offtake at Larcom Creek) are illustrated in Figure 8, which also shows the initial installed capacity and increased capacity after completion of the current expansion program.

Figure 7 **Modelled annual gas throughput on the Queensland Gas Pipeline**



Source: ACIL Tasman GMG Australia modelling

The modelling shows that no gas is delivered to the Gladstone domestic market via the QCLNG Export Pipeline—even on a short term basis during the ramp-up to full LNG production—despite the fact that a tie-in from the QCLNG pipeline to the Gladstone City Gate was assumed for modelling purposes. No tariff was imposed on the tie-in pipeline. The tariff on the QCLNG Export Pipeline was set consistent with the analysis described in Chapter 7.

The existing QGP (with expansion) provides a more economical transportation option because:

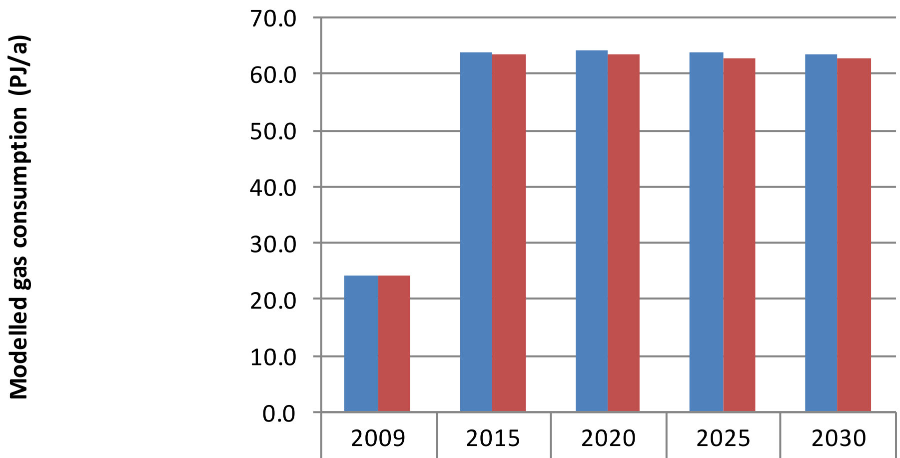
- The capped tariff on QGP (load factor adjusted) is only slightly more expensive than the corresponding tariff on QCLNG—A$0.88/GJ compared to A$0.81/GJ and escalates only at 5-year steps at 80% CPI.
- The distance based tariff on QGP means that for CSG able to join QGP mid-line, the mainline tariffs are likely to be lower than the tariff on the QCLNG Export Pipeline.
- Most CSG looking to use the QCLNG pipeline would also face some transport costs (part forward haul or backhaul) on the Roma-Brisbane Pipeline. The combination of charges for QCLNG plus RBP is typically higher than the capped charge on for gas delivered directly to QGP.

As indicated in Figure 7, the modelling results assume that further expansion of the QGP, beyond the current upgrade which will see capacity increase to around 52 PJ/a from April 2010, will be possible. Furthermore, it is assumed that this additional capacity will be able to be provided at the current prevailing tariff rates.

Project Case, 3-train sensitivity

Figure 8 compares the total level of modelled gas consumption in Gladstone under the Project Case with the 3-train sensitivity, under which an additional LNG train is brought into production at the QCLNG Project in 2015-16. As might be expected, the 3-train sensitivity results in slightly reduced consumption in Gladstone as a result of increased competition for gas supply and higher resultant gas prices.

Figure 8 **Comparison of modelled gas consumption at Gladstone— "Project Case" vs "Project Case 3-train sensitivity"**

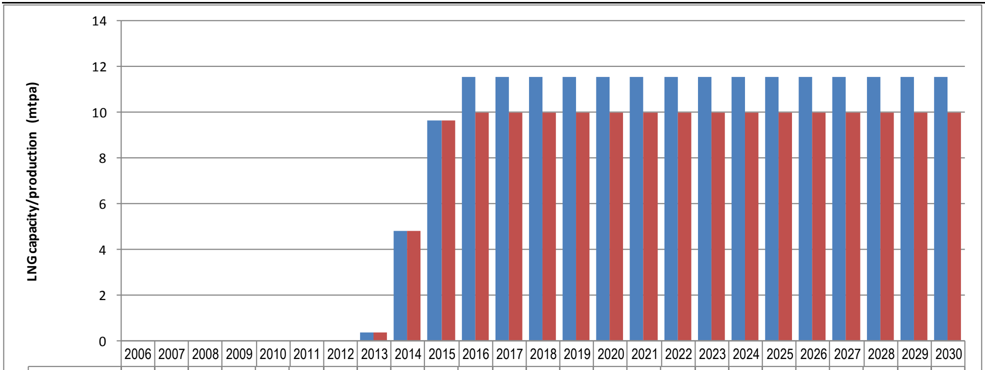


	2009	2015	2020	2025	2030
Gladstone Project Case	24.2	64.0	64.2	64.0	63.6
Gladstone Project 3-train	24.2	63.5	63.4	63.1	62.8

Source: ACIL Tasman GMG Australia modelling

The modelling results for the 3-train sensitivity also show that the level of production from the third LNG train is less than the assumed design capacity (4 mtpa nominal; 3.65 mtpa effective after adjustment for plant availability/load factor), reflecting the fact that additional CSG reserves and production capacity would be required to support a third LNG train (Figure 9).

Figure 9 **"Project Case" 3-train sensitivity: effective LNG capacity vs production**



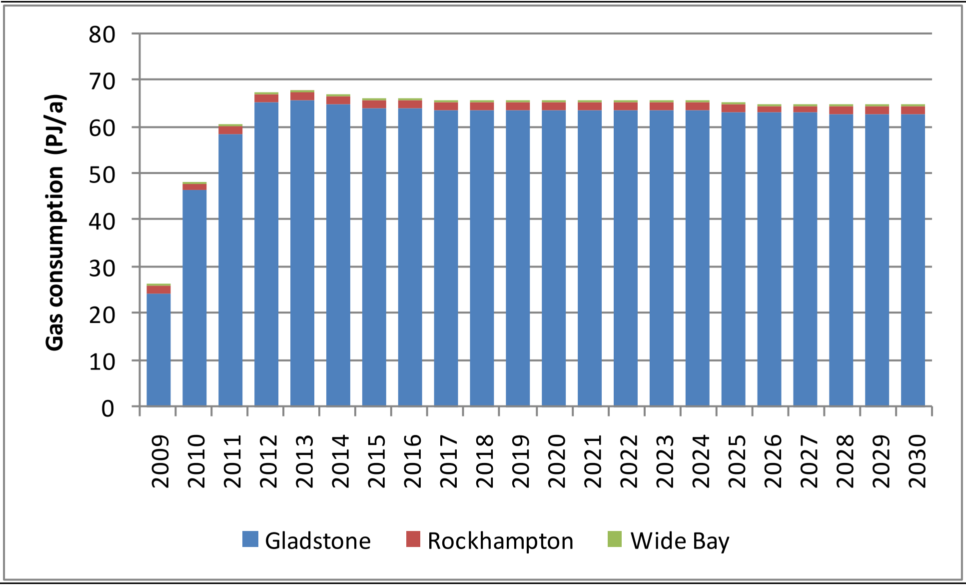
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity	0	0	0	0	0	0	0	0.32	4.81	9.62	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
LNG production	0	0	0	0	0	0	0	0.32	4.81	9.62	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Source: ACIL Tasman GMG Australia modelling

"Industry Case"

The corresponding results under the "Industry Case" with seven LNG trains and increased CSG production capacity are shown in Figure 10 and Table 7. The overall patterns of domestic gas consumption in the Gladstone, Rockhampton and Wide Bay areas are very similar to the "Project Case".

Figure 10 **Modelled gas consumption—"Industry Case"**



Source: ACIL Tasman GMG Australia modelling

Table 7 **Summary of modelled gas consumption, by regional market—"Industry Case"**

	2009	2015	2020	2025	2030
Gladstone	24.4	64.3	63.7	63.3	62.9
Rockhampton	1.6	1.7	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
TOTAL	**26.3**	**66.4**	**65.7**	**65.4**	**65.0**

Data source: ACIL Tasman GMG Australia modelling

Table 8 shows the corresponding detailed breakdown of consumption in Gladstone, by customer.

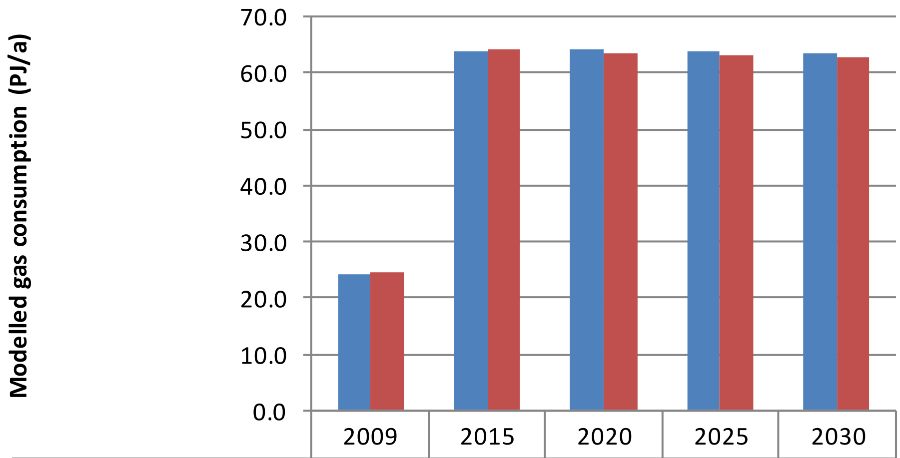
Table 8 **Modelled gas consumption in Gladstone—"Industry Case"**

	2009	2015	2020	2025	2030
Boyne Is. Smelter	1.5	1.5	1.5	1.5	1.5
QAL Cogen	0.0	11.4	11.1	11.0	10.9
Orica - NaCN cholalkali	1.6	1.5	1.5	1.5	1.4
Orica NH4NO3 expansion	4.6	4.6	4.4	4.2	4.2
Comalco Refinery - Calcining	4.4	4.4	4.4	4.4	4.4
QAL Alumina Plant	12.0	12.7	12.8	12.7	12.5
QAL - Alumina Plant Expansion	0.0	5.2	5.0	4.9	4.8
Gladstone Base Market	0.2	0.2	0.3	0.3	0.3
CAR Stage 2 Calcining	0.0	7.2	7.2	7.2	7.2
CAR Stage 2 Cogen	0.0	15.6	15.6	15.6	15.6
TOTAL	**24.4**	**64.3**	**63.7**	**63.3**	**62.9**

Note: ACIL Tasman *GMG Australia modelling*

As shown in Figure 11, there is relatively little difference in projected consumption in the dominant Gladstone market over the projection period. The modelled consumption levels are slightly lower in the "Industry Case", reflecting the increased LNG output which is largely offset by stronger production and reserves assumptions associated with this case. The differences, however, are insignificant given the uncertainties surrounding the timing and scale of new gas loads in the Gladstone region.

Figure 11 **Comparison of modelled gas consumption at Gladstone**



	2009	2015	2020	2025	2030
Gladstone Project Case	24.2	64.0	64.2	64.0	63.6
Gladstone Industry Case	24.4	64.3	63.7	63.3	62.9

Source: ACIL Tasman GMG Australia modelling

2.7.2 Gas prices

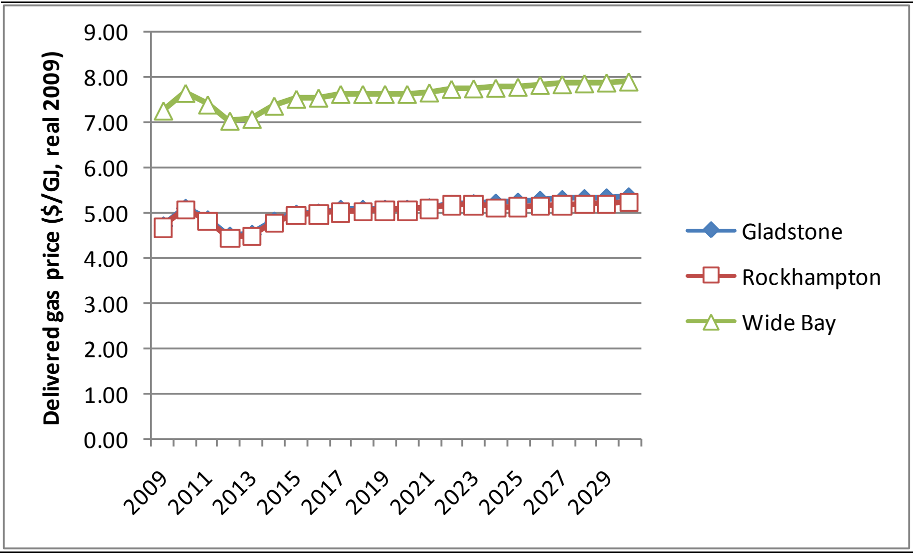
A note on modelled gas prices

The gas prices generated in the *GMG Australia* model are market clearing prices that represent the delivered price of the last unit of gas supplied at each market node represented in the model. The actual price paid by any particular wholesale gas buyer under a gas supply contract may be higher or lower than the modelled price. Contract prices may vary in response to a range of factors including the volume and term of gas sales under the contract, the level of flexibility provided to vary offtake, take-or-pay levels etc. Because the model settles annually, we do not capture seasonal variations in price or demand: essentially the prices are the average prices over the year, assuming an efficient market settlement.

Gas prices for the "Project Case"

The modelled gas prices (expressed in real 2009 A$/GJ terms) under the "Project Case" are illustrated in Figure 12. As shown, real gas prices at the margin tend to decline over the period from 2011 to 2013, reflecting the ramp up of CSG production in the region. Prices in Gladstone and Rockhampton are very similar, while prices in the Wide Bay region (illustrated here by projected prices for wholesale delivery to Bundaberg) are significantly higher, with the difference representing the cost of transportation of gas from Gladstone via the Wide Bay Transmission Pipeline. It should be noted that because the Wide Bay Pipeline is not covered under the National Gas Law and Rules, there is no public information on the transmission charges for use of the pipeline and the delivered price differential indicated is therefore based on ACIL Tasman's estimates of the cost of transport on the Wide Bay pipeline. Details of the modelled wholesale delivered price, by regional market, are provided in Table 9.

Figure 12 **Modelled gas prices—"Project Case"**



Source: ACIL Tasman GMG Australia modelling

Table 9 **Modelled wholesale gas prices, by regional market—"Project Case" (Real 2009 A$/GJ, delivered)**

	Gladstone	Rockhampton	Wide Bay
2009	4.72	4.68	7.27
2010	5.11	5.08	7.66
2011	4.85	4.82	7.40
2012	4.49	4.45	7.04
2013	4.53	4.49	7.08
2014	4.82	4.79	7.37
2015	4.98	4.95	7.53
2016	5.01	4.97	7.56
2017	5.09	5.01	7.64
2018	5.09	5.02	7.64
2019	5.09	5.06	7.64
2020	5.09	5.06	7.64
2021	5.12	5.09	7.67
2022	5.20	5.17	7.75
2023	5.22	5.18	7.77
2024	5.23	5.12	7.78
2025	5.25	5.13	7.80
2026	5.29	5.15	7.84

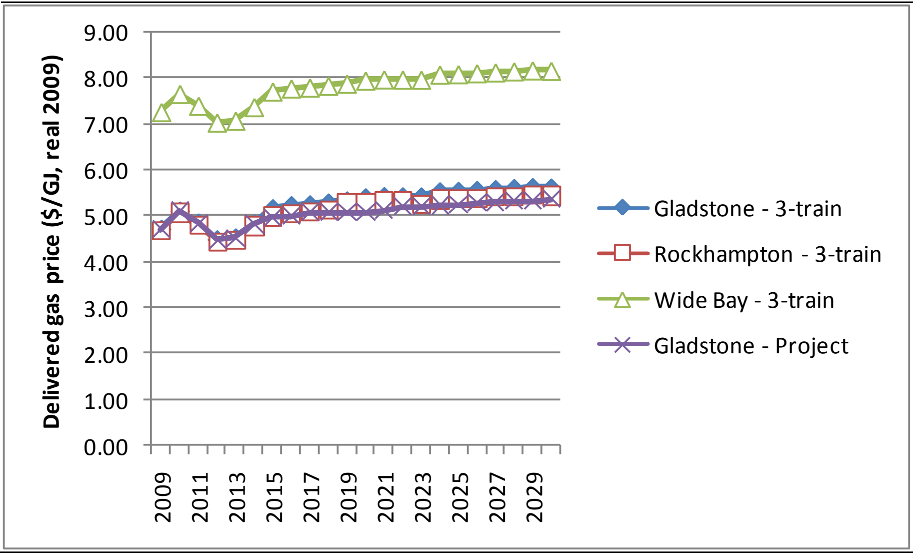
2027	5.31	5.17	7.86
2028	5.33	5.19	7.88
2029	5.35	5.21	7.90
2030	5.37	5.23	7.92

Data source: ACIL Tasman GMG Australia modelling

Gas prices for the "Project Case" 3-train sensitivity

Figure 13 shows the modelled gas prices (expressed in real 2009 A$/GJ terms) under the "Project Case" 3-train sensitivity. The Gladstone city gate prices under the Project Case are also shown for the sake of comparison. As shown, prices are somewhat higher from 2015 as a result of the commencement of production from the third train. The modelled price impact at Gladstone is of the order of A$0.25/GJ. Again, real gas prices at the margin tend to decline over the period from 2011 to 2013, reflecting the ramp up of CSG production in the region. Details of the modelled wholesale delivered price, by regional market, are provided in Table 10.

Figure 13 **Modelled gas prices—"Project Case" 3-train sensitivity**



Source: ACIL Tasman GMG Australia modelling

Table 10 **Modelled wholesale gas prices, by regional market—"Project Case" 3-train sensitivity (Real 2009 A$/GJ, delivered)**

	3-train sensitivity			Project Case		
	Gladstone - 3-train	Rockhampton - 3-train	Wide Bay - 3-train	Gladstone - Project	Rockhampton - Project	Wide Bay - Project
2009	4.72	4.68	7.27	4.72	4.68	7.27
2010	5.11	5.08	7.66	5.11	5.08	7.66
2011	4.85	4.82	7.40	4.85	4.82	7.40

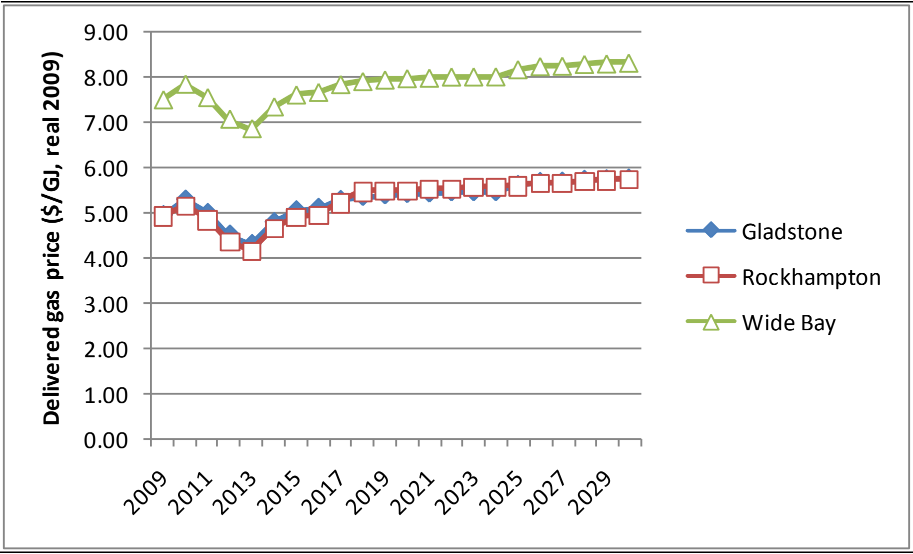
2012	4.49	4.45	7.04	4.49	4.45	7.04
2013	4.53	4.49	7.08	4.53	4.49	7.08
2014	4.82	4.79	7.37	4.82	4.79	7.37
2015	5.16	5.01	7.71	4.98	4.95	7.53
2016	5.23	5.07	7.78	5.01	4.97	7.56
2017	5.25	5.09	7.80	5.09	5.01	7.64
2018	5.29	5.13	7.84	5.09	5.02	7.64
2019	5.33	5.30	7.88	5.09	5.06	7.64
2020	5.40	5.31	7.95	5.09	5.06	7.64
2021	5.43	5.33	7.98	5.12	5.09	7.67
2022	5.42	5.34	7.97	5.20	5.17	7.75
2023	5.42	5.26	7.97	5.22	5.18	7.77
2024	5.53	5.38	8.08	5.23	5.12	7.78
2025	5.54	5.39	8.09	5.25	5.13	7.80
2026	5.56	5.41	8.11	5.29	5.15	7.84
2027	5.58	5.42	8.13	5.31	5.17	7.86
2028	5.60	5.45	8.15	5.33	5.19	7.88
2029	5.63	5.47	8.18	5.35	5.21	7.90
2030	5.62	5.46	8.17	5.37	5.23	7.92

Data source: ACIL Tasman GMG Australia modelling

Gas prices for the "Industry Case"

The corresponding modelled prices for the "Industry Case" are summarised in Figure 14 and detailed in Table 11.

Figure 14 **Modelled gas prices—"Industry Case"**



Source: ACIL Tasman GMG Australia modelling

Table 11 **Modelled wholesale gas prices, by regional market—"Industry Case" (Real 2009 A$/GJ, delivered)**

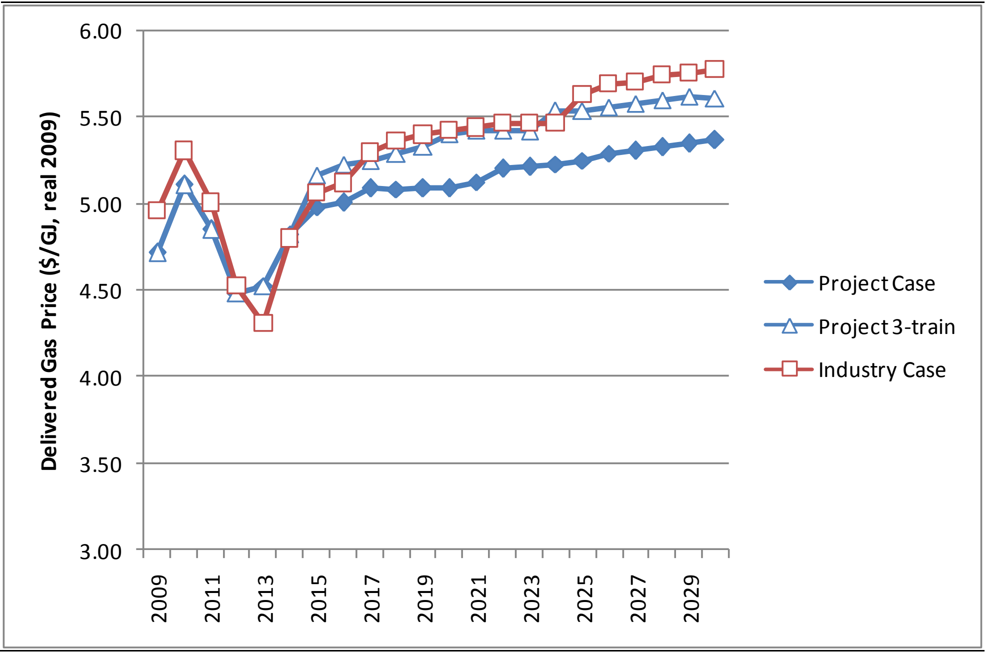
	Gladstone	Rockhampton	Wide Bay
2009	4.96	4.92	7.51
2010	5.31	5.15	7.86
2011	5.01	4.85	7.56
2012	4.52	4.37	7.07
2013	4.31	4.15	6.86
2014	4.80	4.64	7.35
2015	5.07	4.91	7.62
2016	5.12	4.96	7.67
2017	5.30	5.23	7.85
2018	5.36	5.48	7.91
2019	5.40	5.50	7.95
2020	5.43	5.51	7.98
2021	5.44	5.53	7.99
2022	5.47	5.55	8.02
2023	5.47	5.57	8.02
2024	5.47	5.59	8.02
2025	5.63	5.60	8.18
2026	5.70	5.67	8.25
2027	5.71	5.68	8.26
2028	5.75	5.72	8.30
2029	5.76	5.73	8.31
2030	5.78	5.74	8.33

Data source: ACIL Tasman GMG Australia modelling

Gas price comparison – Gladstone

As shown in Figure 15, modelled prices under the "Project Case" are initially slightly lower than for the "Industry Case". This reflects differences in the supply cost curve assumptions and the assumed ramp up profiles of CSG reserves and production capability in the Surat and Bowen Basins. However, in the period immediately prior to start-up of LNG production, modelled prices under the "Industry Case" fall below the "Project Case" prices, reflecting the larger volumes of ramp-up gas available in the market with the increased production capacity assumed for the "Industry Case". Following commissioning of the LNG plants, the "Project Case" with 3-train sensitivity moves close in price to the "Industry Case", with the upward shift in prices reflecting that fact that the sensitivity test introduces a third LNG production train without any commensurate increase in overall CSG production capability, so that the domestic market is reliant on higher cost sources. The results emphasise the fact that future price outcomes will be critically dependent on the profile of reserves and production build-up, compared to the profile of demand growth.

Figure 15 **Comparison of modelled wholesale gas prices delivered at Gladstone**



Source: ACIL Tasman GMG Australia modelling

3 LNG market projections to 2030

Chapter Summary

Since early 2007, at least six LNG proposals based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been announced. The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant. Total proposed capacity is initially 16.8 mtpa, rising to 40.6 mtpa if plans are fully developed to their ultimate potential.

The Chapter provides short summarises of each of the main LNG proposals.

The following are the most advanced project proposals:

- Queensland Curtis LNG (QGC/BG Group): two LNG trains, each with nominal capacity of 4 mtpa, with the first on line late 2013, second during 2014. A third train, also 4 mtpa, is proposed but timing is uncertain.
- Gladstone LNG (Santos/Petronas): First train 3 to 4 mtpa from early 2014; potential for three trains up to 10 mtpa.
- APLNG (Origin/ConocoPhillips): Two trains each of 3.5 mtpa with first targeting production in 2014; potential for a further two trains of similar size, timing uncertain.
- Arrow/LNG Limited: Mid size project with 1 or 2 trains each of 1.3 to 1.5 mtpa capacity, to be located on the mainland at Fisherman's Landing, 10km north of Gladstone. Targeting first production in 2012.

Until recently, Eastern Australia has not been considered a prospective location for LNG manufacture, principally because uncommitted conventional gas resources in the region are inadequate to support a world-scale LNG facility. However, the surge in international energy prices through 2007 and 2008, together with the identification of large resources of CSG in southern and central Queensland, has changed the prospects for East Coast LNG. Since early 2007, six LNG proposals based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been announced as detailed in Table 12.

The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant. Total proposed capacity is initially 16.8 mtpa, rising to 40.6 mtpa if plans are fully developed to their ultimate potential.

While posing many technical and commercial challenges for the proponents, there is a compelling logic to the attempts of the proponents to access large, high value international markets at a time of burgeoning demand and tight supply.

Table 12 **Overview of Queensland LNG export proposals**

Proponent	Announced	Train 1 capacity	Schedule for first cargoes	Gas feed required (Train 1)	Liquefaction Technology	Comments
LNG Ltd/Arrow Energy (FLLNG)	May-07	1.3 to 1.5 mtpa	December 2012	72 to 85 PJ/a	LNG Ltd Optimised Single Mixed Refrigerant	Project located at Fisherman's Landing Gladstone. Estimated capital costs of US$400 million for Train 1. Potential for a second train of the same size. FID originally anticipated late 2008; Financial Close is now anticipated April 2010.
Santos/Petronas (GLNG)	Jul-07	3 to 4 mtpa	Early 2014	165 to 220 PJ/a	ConocoPhillips Optimised Cascade	Project located on Curtis Island will initially produce 3 to 4 mtpa, with a maximum potential production of 10 mtpa. Reported capital cost of A$7.7 billion in 2007 dollar terms. In May 2008 Santos sold a 40% interest in the GLNG project to Petronas for US$2.008 billion plus US$500 million upon FID of GLNG Train 2 using JV gas. Target FID for Train 1 originally anticipated by end of 2009, now 1H2010.
Sojitz	Dec-07	0.5 mtpa	(Early 2012)	30 PJ/a	Unknown	Proposed LNG plant at Fisherman's Landing Gladstone, previously joint ventured with Sunshine Gas. FID initially intended for end 2008, with first cargoes early 2012. Train size of 0.5 mtpa which can be developed as modules. Takeover of Sunshine Gas by QGC and subsequently BG may result in Sojitz looking for other feedstock gas.
BG Group (QCLNG)	Feb-08	3 to 4 mtpa	Late 2013 - Early 2014	165 to 220 PJ/a	ConocoPhillips Optimised Cascade	Initial design for 3-4 mtpa, with potential expansion to up to 12 mtpa subject to additional gas reserves. Estimated capital cost of A$8 billion including upstream gas fields and pipeline. Initially a joint venture between QGC and BG Group, BG has since acquired QGC. Final investment decision scheduled for early 2010.
LNG Impel	May-08	0.7 to1.3 mtpa	2013	39 to 72 PJ/a	Unknown	Proposed construction as modules of between 0.7 and 1.3 mtpa. Site at Curtis Island has been scoped for up to 3 trains. Open-access LNG plant projects to be designed on a toll for service basis with 15 to 20 year contracts.
Shell/Arrow (SALNG)	June-08	3 to 4 mtpa	2014 - 2015	165 to 220 PJ/a	Not yet determined	LNG plant site on Curtis Island. Proposal for up to 4 trains giving total LNG capacity of up to 16 mtpa. FID target not announced.

Origin/ConocoPhillips (APLNG)	Sep-08	3.5 mtpa	Late 2014	195 PJ/a	ConocoPhillips Optimised Cascade	ConocoPhillips to invest up to A$9.6 billion for a 50% share in CSG to LNG project proposed for Gladstone. Plans for ultimately up to 4 x 3.5 mtpa LNG trains. 50/50 joint venture alignment for whole project. FID scheduled 2010 for construction leading to first delivery by end 2014.

Data source: ACIL Tasman based on company announcements

The following sections summarise the current proposals for LNG projects based on CSG feed.

3.1.1 Santos/Petronas Gladstone LNG (GLNG)

Santos in joint venture with Petronas of Malaysia is proposing to develop its coal seam gas (CSG) resources in the Bowen and Surat Basins as feed gas for an LNG liquefaction and export facility The proposed facility would have an initial capacity of 3 to 4 mtpa, with potential for expansion to as much as 10 mtpa.

Petronas took a 40% stake in the Santos Gladstone LNG Project and associated CSG reserves in May 2008 for an upfront payment of approximately US$2 billion plus a further US$500 million contingent on a commitment to develop a second LNG train. Analysts at the time estimated that the transaction valued the 2P (Proven and Probable) reserves of CSG covered by the arrangement at A$4.19/GJ in the ground. This represented a substantial premium on the then-current long term contract prices of sales gas in Eastern Australia, and was much higher than the prices for 2P reserves implied by previous CSG asset purchases.

Public statements by Santos put the cost of the project (including field development, pipeline, LNG liquefaction facilities, storage and shipping facilities) initially at between A$5 and $7 billion, with a subsequent pre-FEED estimate by Santos of A$7.7 billion. Half of the investment is expected to be in the Gladstone plant, with the other half in the upstream CSG production and pipeline facilities. This estimate was prepared in-house by Santos and was based on preliminary engineering and site selection studies and by applying appropriate escalation factors to actual costs incurred in the Darwin LNG project.

The Project as currently configured includes:

- coal seam gas fields, principally in the Bowen Basin (Fairview project and adjoining areas) and also further south in the Surat Basin, near Roma
- a major new gas transmission pipeline to carry gas from the CSG fields to the LNG plant
- an LNG liquefaction and export facility development to be located on Curtis Island at Gladstone.

The coal seam gas fields will be developed and expanded to provide sufficient gas supply to the facility. The proposed LNG facilities will be located on Curtis Island, which is situated approximately 5 km north-east of Gladstone in Central Queensland.

Access to the site will be via a proposed bridge linking Curtis Island (Laird Point area) with the mainland (Friend Point area). A new access road is also proposed to be built on the western side of Curtis Island as well as on the mainland linking the bridge with the existing regional road network.

Gladstone has been chosen over other possible locations for the LNG plant because of its sheltered deep water harbour, existing industrial infrastructure and proximity to the coal seam gas fields.

3.1.2 LNG Ltd/Arrow Energy (FLLNG)

In May 2007, Liquefied Natural Gas Limited entered into a Heads of Agreement with Arrow Energy NL (Arrow Energy) for the supply of 150 TJ/day of gas, commencing in 2010, to a proposed LNG plant of approximately 1 mtpa capacity, to be built in Gladstone. The Heads of Agreement included the option for a further 150 TJ/day of gas, with delivery as early as 2011, to increase LNG production to 2 mtpa, with the development of a 2nd LNG train of ~ 1 mtpa.

The proponents are now talking in terms of a 1.5 mtpa facility, with potential for a second train increasing total LNG production capacity to around 3.0 mtpa.

The LNG plant design will provide for additional LNG trains of similar size, subject to the availability of further gas.

Pre-feasibility studies have subsequently been undertaken. These studies are said to have confirmed that a 1 mtpa facility would cost about $US350 million ($A407 million). In October 2007 Arrow announced that key terms for the Gladstone liquefied natural gas project had been settled, with Arrow to supply 60 PJ of gas from its coal seam methane operations to the facility for 12 years.

The project includes a dedicated pipeline to be built from Arrow's CSG fields in the Surat Basin to Gladstone. The proponent for the Surat to Gladstone Pipeline proposal is Surat Gladstone Pipeline Pty Ltd (SGP) a wholly owned subsidiary of Arrow Energy Ltd. Arrow Energy Ltd currently holds 90 000km^2 of coal seam gas exploration tenements in the Surat Basin. The pipeline is proposed to deliver CSG from adjacent to the Kogan North Central Gas Processing Facility near Dalby to a proposed Liquefied Natural Gas (LNG) facility at Fisherman's Landing near Gladstone. The 660mm diameter high pressure buried steel gas pipeline would be approximately 470km long.

Arrow Energy is currently pursuing both the Fisherman's Landing project and the Shell Australia LNG Project (SALNG) with the Shell Australia—see section 3.1.6.

3.1.3 Sunshine/Sojitz

Sunshine Gas Ltd, in association with Sojitz Corporation, is investigating the development of an LNG facility at Fisherman's Landing Wharf (FLW) near Gladstone.

The first stage of the project—referred to as Project Sun LNG Plant—would produce 0.5 mtpa per year of LNG. Stage 2, if built, would increase the capacity of the LNG plant to 1.0 mtpa.

The project involves the following components:

- a natural gas liquefaction plant on land located at FLW
- loading facilities for export of LNG located on an upgraded berth 5 at FLW
- a 5km lateral gas pipeline from the Gladstone City Gas Gate of the Queensland Gas Pipeline (QGP) to the LNG plant
- associated infrastructure and facilities for the LNG plant site (e.g. power supply, water supply, road upgrades, etc.).

The project is in doubt following QGC's takeover of Sunshine Gas in August 2008, which effectively deprives the project of its source of gas supply.

3.1.4 QGC/BG Group (QCLNG)

In February 2008, Queensland Gas Company (QGC) announced an A$870 million alliance with BG Group plc (formerly part of British Gas) to build a world scale LNG plant on Curtis Island at Gladstone. Subsequently, in October 2008, BG launched a takeover bid for QGC that valued the company at approximately A$5.6 billion. The takeover had the support of the QGC board and major shareholders, and BG completed acquisition of QGC.

Front end engineering and design (FEED) on the Curtis LNG Project commenced in July 2008 with Bechtel as project contractor. The first train of the proposed LNG plant would have a capacity of between 3 and 4 mtpa (similar to Santos proposal) with potential for expansion up to 12 mtpa subject to establishment of sufficient gas reserves.

The project is targeting a final investment decision in early 2010 with commencement of construction in that year. First LNG shipments are scheduled for late 2013.

Capital cost of the LNG project was estimated at A$8 billion (again similar to Santos proposal) for the 3-4 mtpa Train 1 development, with a project life of at least 20 years. Current plans involve construction of a dedicated pipeline from the Surat Basin to Curtis Island (estimated length 341km plus 197km lateral and field header) with the pipeline designed to be capable of carrying sufficient gas for a three-train development. Gas for the project will be sourced from QGC/BG Surat Basin CSG fields, located about 380 km from Gladstone. These projects (in particular Berwyndale South, Argyle and Kenya) have to date proven to be among the most productive CSG fields in Queensland, with high well flow rates and low drilling and completion costs.

A major step forward for the QGC/BG project was the signing of an agreement with China National Offshore Oil Corporation (CNOOC) under which CNOOC will purchase 3.6 mtpa of LNG for a period of 20 years.

3.1.5 LNG Impel

In May 2008 Canadian company LNG Impel announced its intention to build the Southern Cross LNG Project, an open access LNG facility at Gladstone (Curtis Island) (LNG Impel, 2008). The proposed facility would have up to 3 trains, each of 0.7 to 1.3 mtpa capacity, with development staged to match demand from users. The project would also include a high pressure gas transmission pipeline approximately 400 km long and 16 to 24-inch diameter to link the facility to CSG fields in the Bowen and/or Surat Basins, two LNG storage tanks each of 160,000 m3 capacity, and marine loading facilities. The open access concept means that the LNG facility will offer services to third party gas producers, rather than rely on the proponent's own gas reserves. According to LNG Impel, the concept will "allow junior producers access to the international gas markets and provide them with the opportunity to realise an international netback price for their gas reserves". Third party gas producers would either pay a tolling charge to have their gas converted to LNG in the facility, or sell their gas to LNG Impel at a "market-based price".

In November 2008 LNG Impel was reported to be "working towards securing the producer/gas supplies" for the project (Pipeline Publications Australia, 2008). Given that most of the current independently certified proven and probable CSG reserves in the Bowen and Surat Basins are now controlled by proponents of other LNG projects, we find it difficult to see where the LNG Impel project will be able to secure committed gas suppliers at this stage: there are a number of junior explorer/producers of CSG that may will be interested in supplying into the facility, but they do not presently have certified reserves that could be committed into the project to enable it to move ahead.

3.1.6 Shell/Arrow Energy (SALNG)

In June 2008 Royal Dutch Shell entered into an alliance with Arrow Energy to develop jointly Arrow's Australian and international coal seam gas projects. Under the arrangement, Shell acquired 30% of all Arrow's Australian upstream CSG interests as well as 10% of the company's overseas CSG exploration interests. The arrangement also gives Shell the right to off-take LNG produced utilizing gas from the Arrow/Shell upstream tenements, but is not a participant in the Fisherman's Landing LNG project. The announced value of the deal was US435 million with a further US$209 million contingent on development of an LNG project capable of producing at least 1 mtpa. Based on Arrow's 2P reserves of 791 PJ at the time of the transaction, the initial payment represented a valuation of A$1.80/GJ of 2P reserves, while the full price for the transaction would represent a valuation of A$2.70/GJ.

In May 2009 Shell lodged an Initial Advice Statement with the Queensland Government for a large-scale LNG project of up to 16 million tonnes per year (up to four 4 mtpa trains) to be located on Curtis Island at Gladstone. The IAS makes the following statement regarding the source of gas to support this staged development:

> "The project is designed to allow for expansion from expected additional exploration and production success in the future from both the Shell and Arrow Energy CSG tenements, and also potentially from other CSG acreage holders and/or developers ... Shell believes that the Shell and Arrow Energy CSG tenements contain sufficient gas resources for a foundation train. Shell is currently in negotiations with Arrow Energy and others to procure the additional gas necessary to support this project."

The SALNG project is targeting first LNG shipments in 2014 or 2015.

3.1.7 Origin/ConocoPhillips (APLNG)

The most recent proposal for an LNG facility using CSG feed is the Australia Pacific LNG Project, a joint venture between Origin Energy and ConocoPhillips, announced in September 2008. Under this arrangement, ConocoPhillips has made an initial payment of about US$5 billion (A$6.9 billion at the time of transaction), with further contingent payments of up to A$3 billion to acquire a 50% interest in all of Origin's CSG interests. According to Origin (Origin Energy, 2008), this consideration represents a valuation of A$4.00/GJ of 2P reserves and A$1.88/GJ of 3P reserves at the time of the transaction. The joint venture will develop those interests into a CSG to LNG project of up to 14 mtpa capacity (4 liquefaction trains each of 3.5 mtpa). A final investment decision for the first liquefaction train is expected by end 2010, with first LNG shipments scheduled for 2014.

Origin Energy will continue as the upstream CSG exploration and production operator and domestic gas marketer for the JV; ConocoPhillips will be the LNG plant operator and will lead the JV marketing of LNG. Gas feed for the project will come from Origin's Surat and Bowen Basin CSG projects which include Spring Gully, Fairview and Peat in the Bowen Basin, and the Walloon CSG project, including the Talinga and Miles prospects, in the Surat Basin. The full 14 mtpa project would require around 24 tcf (about 25,000 PJ) of CSG over 30 years.

4 Small CSG producer assessment

Chapter Summary

This chapter considers the question whether other CSG producers in the vicinity of the proposed QCLNG Export Pipeline would be likely to benefit significantly from having access to the pipeline. The analysis focuses on those small or emerging CSG producers that are not involved with the various CSG LNG Projects currently proposed, recognising that for those "non-aligned" producers access to an alternative path to market might enhance the prospects of successfully commercialising the CSG within their exploration areas.

The analysis identifies six companies not currently involved in LNG proposals that have CSG resources or exploration areas prospective for CSG that are located within 100 km of the proposed QCLNG Export Pipeline and associated facilities.

However, none of these resource and prospect holders are likely to find that access to the QCLNG Export Pipeline would offer a commercially attractive means of reaching prospective customers compared to the alternatives already available. This is principally because of the tie-in distances, given that most prospects are closer to either the QGP (via the Dawson Valley Pipeline) or the RBP. Other factors mitigating against third party use of the QCLNG Export Pipeline include the short term and/or interruptible nature of the services that could potentially be made available; the need for the third party shipper/s to meet capital costs of offtake facilities, and the possibility that the export pipeline will carry gas of a more exacting specification than the general Australian Standard for sales gas.

In this section, we consider the question whether other CSG producers in the vicinity of the proposed QCLNG Export Pipeline would be likely to benefit significantly from having access to the pipeline. In particular, we focus on those small or emerging CSG producers that are not involved with the various CSG LNG Projects currently proposed, recognising that for those "non-aligned" producers access to an alternative path to market might enhance the prospects of successfully commercialising the CSG within their exploration areas. The analysis draws on a more detailed assessment of small CSG producers in the vicinity of the QCLNG Export Pipeline prepared by RLMS.

4.1 The RLMS Study

RLMS Pty Ltd was separately commissioned by QGC, to estimate the potential natural gas production by small independent producers and tenement holders in the vicinity of the QCLNG export pipeline. The areas of interest for this investigation included those considered within economic reach of QGC's production areas, the proposed natural gas pipeline linking the Company's gas production areas with Gladstone and within proximity to the projected

Queensland Curtis LNG facility on Curtis Island. The area of interest basically encompasses the southern part of the Bowen Basin and virtually all of the Surat Basin in southern Queensland.

The approach adopted by RLMS can be summarised as follows:

- A 100-km corridor was identified around the QGC operated gas fields and tenements, other tenements in which QGC has a commercial interest, the proposed QCLNG Export Pipeline and the Queensland Curtis LNG site on Curtis Island.
- Within that corridor, all exploration tenements not currently controlled by the proponents of the four major CSG LNG projects at Gladstone (that is, QGC/BG; Santos/Petronas; Origin Energy/ConocoPhillips; Arrow/Shell) were identified.
- Each of the identified exploration tenements was assessed in terms of its resource and production potential; target market opportunities; and options for gas transportation to target markets.

The analysis showed that the majority of the CSG-prospective land with the 100-km corridor is controlled by one or other of the CSG LNG proponents. The ASX listed companies not directly involved in the LNG projects that hold interests in tenements within the 100 km corridor include:

- A J Lucas Limited
- Blue Energy Limited
- Bow Energy Limited
- Icon Energy Limited
- Molopo Australia Limited
- Rawson Resources Limited
- Victoria Petroleum NL
- WestSide Corporation Limited

Of these companies, the interests of A J Lucas Limited, Victoria Petroleum NL and WestSide Corporation Limited in tenements in the Bowen and Surat Basins within the QGC area of interest are all in association or joint venture with QGC, and so are regarded as being LNG-associated.

Non ASX listed companies with CSG or conventional petroleum interests in the area under consideration include:

- Anglo Coal [Moura] Limited
- Clark Energy Pty Ltd
- Pangaea Resources Pty Ltd

Pangaea and Clark Energy hold areas in the southern Surat Basin, both well south of the Roma-Brisbane Pipeline. Both companies' exploration areas are considered to be more prospective for conventional petroleum due to the depths at which the Walloon Coal Measures are expected to lie. Some shallower Cretaceous coals may occur within the acreage but no drilling has been undertaken to evaluate this resource.

In summary, the small independent (non-LNG aligned) CSG prospects located within a 100-km corridor of the QCLNG facilities are those summarised in Table 13, and illustrated in Figure 16.

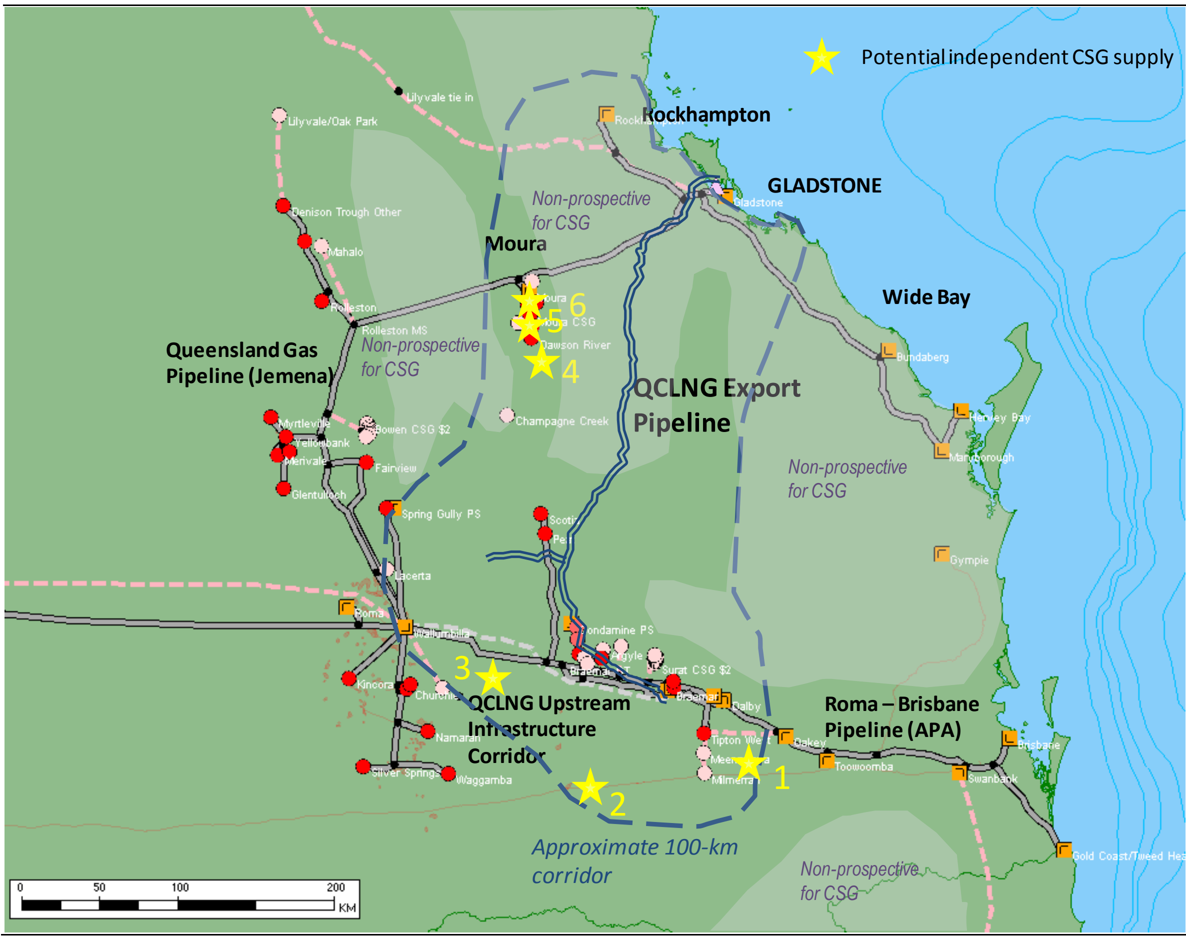
Table 13 **Summary of small independent CSG prospects proximate to QCLNG**

Map Ref	Holder	ATP	Prospect	Potential recoverable gas (PJ)	Potential production rate (PJ/a)	Comments
1	Blue Energy	818, 896	Eastern Surat	880 - 1,760	44 - 88	Adjacent to RBP; logical markets to east or south
2	Icon Energy	626	Lydia	600 - 1,200	30 - 60	Southern location makes RBP most likely path to market
3	Rawson Resources	893, 901	Dulacca South	na	na	Untested geological play; southern location makes RBP most likely path to market
4	Bow Energy	1053	Gunyah	145 - 290	7 - 15	25km from QCLNG; more likely development through existing Dawson Valley infrastructure
5	Molopo	564, 602; PL 94, PLA 210	Dawson Valley	945 - 1,890	47 - 94	Current production through existing Dawson Valley infrastructure
6	Anglo Coal	Moura coal mining leases	Moura	386*	6	Current production through existing Dawson Valley infrastructure. In process of sale; Molopo holds pre-emptive rights

Data source: RLMS, company websites

Note: * RLMS estimate of 2P reserves.

Figure 16 **Location of small independent CSG prospects proximate to QCLNG**



Source: ACIL Tasman compilation; map base from GMG Australia model

The following sections discuss each of the identified prospects in turn.

4.1.1 Blue Energy, Oakey & Millmerran Prospects (Map Ref 1)

In the area within 100 km of the proposed QGC pipeline, Blue Energy has one tenement area located in the eastern part of the Surat Basin. ATP's 818P and 896P are centred around Oakey, Pittsworth and Millmerran to the west of Toowoomba and east of Dalby and Arrow's Tipton West and Meenawarra Blocks. The Roma to Brisbane Pipeline (RBP) passes through both ATP 818P and ATP 896P.

The total recoverable resource in the relevant Blue Energy areas is estimated at between 880 and 1,760 PJ which, if produced over 20 years could sustain a production rate of between 44 and 88 PJ/a.

The areas are located over 100 km from the Berwyndale South gas processing hub and over 50 km from the nearest QGC tenement [PL 279]. The location of the Blue Energy tenements makes it much more likely that any future production would be used locally or supplied to the South East Queensland gas market via the RBP. Targeting markets in Gladstone via the QCLNG Export Pipeline would require a 95 km, 450 mm pipeline capable of operating 10.2 MPa, at an estimated cost of A$77 million.

The alternative of connecting future CSG production from these prospects to the RBP would have a much lower capital cost—estimated by RLMS at A$3.25 million—and would also provide the option of accessing the Gladstone/ Central Queensland market via backhaul on RBP and forward haul on the Queensland Gas Pipeline (QGP) from Wallumbilla.

Blue Energy also has prospective areas in the northern Bowen Basin and the eastern Galilee Basin that could potentially supply the Gladstone-Central Queensland area via the proposed Central Queensland Gas Pipeline from Moranbah to Gladstone.

4.1.2 Icon Energy, Lydia Prospect (Map Ref 2)

Icon Energy holds ATP 626P in the southern part of the Surat Basin. Icon is focusing its exploration, appraisal and development activities on its 100% controlled Surat Basin Lydia Prospect.

Icon has an agreement with Stanwell Corporation under which Icon will deliver 225 PJ of gas over 15 years after proving up 340 PJ of 2P gas reserves. Stanwell proposes to use the gas for power generation. Currently Icon has 373 PJ of contingent gas resource [2C] at Lydia out of an estimated 808 PJ resource as gas in place. The total recoverable gas resource in ATP 626P is estimated by RLMS at up to 1,200 PJ or a maximum of 60 PJ per year over 20 years.

While the early production of CSG from Lydia will be taken by Stanwell Corporation, Icon is pursuing gas markets in its own right. The closest existing gas infrastructure is the RBP, approximately 110 km to the north. The route of the proposed Queensland Hunter Gas Pipeline passes 75 km to the west of ATP 626P.

Icon is unlikely to pursue gas markets in Central Queensland given the location of ATP 626P with the Lydia Project being over 110 km south of the RBP. In any case, connection to the RBP would also provide the option of accessing the Gladstone/ Central Queensland market via backhaul on RBP and forward haul on the Queensland Gas Pipeline (QGP) from Wallumbilla.

4.1.3 Rawson Resources, Dulacca South Prospect (Map Ref 3)

Rawson Resources Limited has two ATP's in the southern part of the Surat Basin south of the RBP. The northern section of ATP 893P is between 50 km and 100 km from the proposed QGC pipeline. Part of Rawson's other tenement [ATP 901P] is just within the 100 km of the QGC pipeline route.

The exploration areas are on the western edge of the Taroom Trough where the Walloon Coal Measures dip steeply with the seams targeted elsewhere in the Surat Basin lying at depths of more than 1,000 m—deeper than generally considered suitable for the economic recovery of CSG. As a result Rawson Resources is proposing to investigate shallower [400m-500m] Cretaceous coal seams which are known to exist in the area. These coal seams are not as mature as the Jurassic Walloon Coal Measure and their suitability for CSG recovery has yet to be tested. Rawson Resources has not announced any estimates for a gas in place resource.

Because of its location, any prospective gas production from ATP's 893P and 901P would connect to either the RBP or the proposed Queensland Hunter Gas Pipeline.

4.1.4 Bow Energy, Gunyah Prospect (Map Ref 4)

Bow Energy Limited is currently pursuing a number of prospective CSG developments in the Bowen and Surat Basins. The company's principal focus of Bow Energy is on its Comet Block [ATP 1025P] and Norwich Block [ATP 1031P] in the Bowen Basin and the Don Juan Project [ATP's 771P and 593P] based on the Walloon Coals of the Surat Basin. None of these prospects lies within 100 km of the proposed QCLNG pipeline.

The only tenement held by Bow Energy close to the proposed QGC gas pipeline is the Gunyah Block [ATP 1053P], located in the southern part of the Dawson Valley to the west of Cracow. While the QGC pipeline route passes 25 km to the east of ATP 1053P, any lateral linking the Gunyah Block to the pipeline would have to traverse very rugged country including the Auburn Range. The Gunyah Block has been offered to Bow Energy by the Queensland Government subject to finalization of a Native Title Agreement expected in early 2010. Until then, Bow is unable to undertake any exploration work over the Gunyah Block. However based on drilling data from adjacent tenements, RLMS has estimated a CSG resource in the Gunyah Block of 970 PJ gas-in-place (GIP). Assuming that up to 30% of the GIP resource could be recovered as deliverable gas, Gunyah could potentially sustain a gas supply of up to 15 PJ per year over a 20 year period.

The Gunyah Block is a southern extension of the Dawson Valley gas fields and is located immediately to the south of the Anglo Coal Pty Ltd–Molopo Australia Limited Timmy Prospect [ATP 602P]. While gas produced at Gunyah could potentially use the QCLNG pipeline as a means of supplying gas to Gladstone, a more likely alternative would be for it to connect into the existing

Dawson Valley gas processing pipeline infrastructure which is already connected into the QGP. The Gunyah Block would require a new lateral of approximately 40 km though if the Timmy Gas Field in ATP 602P is developed first by Anglo Coal-Molopo, only about 15 km of new gas pipeline would be needed.

4.1.5 Molopo, Dawson Valley Production Areas (Map Ref 5)

Molopo's principal gas interests in Queensland are in CSG exploration, development and production in the Dawson Valley. The Company has a 50% interest in each of the Mungi CSG Project [PL 94-Northern Section], Harcourt/Bindaree [ATP 564P/PLA 210] and the Timmy Project [ATP 602P]. The other interests in these tenures are Anglo Coal [Moura] Limited [25.5% and operator] and Mitsui Moura Investments Pty Ltd [24.5%].

The Mungi CSG Gas Field is located near Moura and west of Anglo's Dawson Valley coal mines. Gross gas production at Mungi in 2008-2009 was 0.7 PJ though production is now increasing to an expected rate of 2.2 PJ per year. Currently the estimated resource at Mungi is 1,500 PJ as gas in place.

ATP 564P/PLA 210, the Harcourt Project is located immediately north of Mungi. Current estimates of the CSG resource are 2,500 PJ as gas in place.

To the south of PL 94 is the Timmy Project with an estimated CSG resource in place of 2,300 PJ. Timmy is located within 50 km of the proposed QCLNG Export Pipeline.

The gas treatment and transmission facilities in the Dawson Valley have a maximum design operating pressure of 10 MPa though the system operates in the 7 MPa to 8 MPa range. The existing facilities are approximately 80 km from the proposed QGC pipeline with the current connection to the QGP being approximately 25 km. Because of the distances involves, as well as the technical issues involved in upgrading the Dawson Valley system to make it compatible with QGC proposed pipeline, gas produced by Molopo and Anglo aimed for the Central Queensland gas market is most likely to utilise the existing Dawson Valley gas infrastructure and the QGP.

4.1.6 Anglo Coal, Moura Production Areas (Map Ref 6)

Anglo Coal [Moura] Limited, a subsidiary of Anglo Coal Australia Pty Ltd, in joint venture with Mitsui Moura Investments Pty Ltd, recovers CSG from its coal leases in the Dawson Valley, south of Moura. The Anglo/Mitsui joint venture also has a 50/50 agreement with Molopo Australia Limited (see above) in CSG tenements off the coal mining leases. Anglo is reportedly seeking to sell its CSG interests and it is understood that Molopo has pre-emptive rights over the interests held in JV with Anglo. As discussed in the preceding section, any further expansion in CSG production from the Anglo-Mitsui leases or the adjoining Anglo/Molopo joint venture areas is almost certain to be handled by augmentation of the existing Dawson Valley transmission system which is integrated with the QGP. The Anglo CSG facilities are approximately 70 km west of the proposed QCLNG pipeline route with the rugged terrain of the Banana Range in between.

4.2 Other considerations

Apart from the issue of capital and operating cost associated with connecting into the large diameter QCLNG system, there are a number of other factors that make it unlikely that the QCLNG Export Pipeline system would provide an economically-preferred option for small independent CSG producers in Surat and Bowen Basins looking to access markets. These include:

- **Short-term and/or interruptible capacity:** Because the QCLNG project is likely to require all of the initially installed capacity in the export pipeline once the planned third LNG train is commissioned, transport services could only be offered to small independent CSG producers on a short-term and/or interruptible basis. This may not meet the delivery and supply security requirements of prospective customers. It also poses a significant risk to the third party shipper if it has incurred substantial capital costs for connection that cannot be fully recovered over a short period of time.
- **Offtake facilities:** The QCLNG proponents are not proposing to use the Export Pipeline for gas delivery into the domestic market and will not therefore provide a connection into the Gladstone City Gate or other interface with the existing transmission pipeline system. Any third party shipper/s looking to access capacity in Export Pipeline system would therefore face the capital cost of such a connection, in addition to the cost for tie-in to the QCLNG pipeline from their production facilities.
- **Gas quality issues:** QGC will treat gas at its upstream processing facilities to a narrow gas specification required for the LNG plant on Curtis Island. For small CSG producers, treating the gas to meet the required specifications for the LNG plant would involve additional costs that would not be incurred for transportation in the RBP or QGP.

4.3 Conclusions regarding small, independent CSG producers

Based on this analysis, none of the small independent CSG tenement holders with 100 km of the proposed QCLNG Export Pipeline are likely to find that access to this pipeline would offer a commercially attractive alternative means of reaching prospective customers. This is principally because of the tie-in distances, given that most are closer to either the QGP (via the Dawson Valley Pipeline) or the RBP. Other factors mitigating against third party use of the

QCLNG Export Pipeline include the short term and/or interruptible nature of the services that could potentially be made available; the need for the third party shipper/s to meet capital costs of offtake facilities, and the fact that the export pipeline will carry gas of a more exacting specification than the general Australian Standard for sales gas.

Molopo and Icon Energy have both entered into gas sales agreements—Molopo for supply at Moura and in Gladstone (via the Dawson Valley Pipeline and QGP) and Icon for supply to Stanwell's electricity generation interests in southern Queensland (via the RBP and on a conditional basis subject to proving of reserves). These agreements demonstrate that the small independent CSG currently have a number of practical options for delivering their gas to markets.

5 QGP transport cost assessment

Chapter Summary

This chapter provides information on the existing Queensland Gas Pipeline (QGP), owned and operated by Jemena Limited, and on the costs associated with transporting gas to the relevant markets via the QGP.

For existing users, charges on the pipeline are currently limited by a rate cap of A$0.795/GJ of capacity reserved (A$0.71/GJ after the Expansion Date, which is the date upon which the Service Provider first commences transportation Services under Access Agreements providing for firm Contracted Capacity for Firm Forward Haul Services of 25 PJ or more on an annualised basis). For new users, the charge for firm capacity is A$0.795/GJ (as at 1 July 2008) indexed by CPI on 1 January each year.

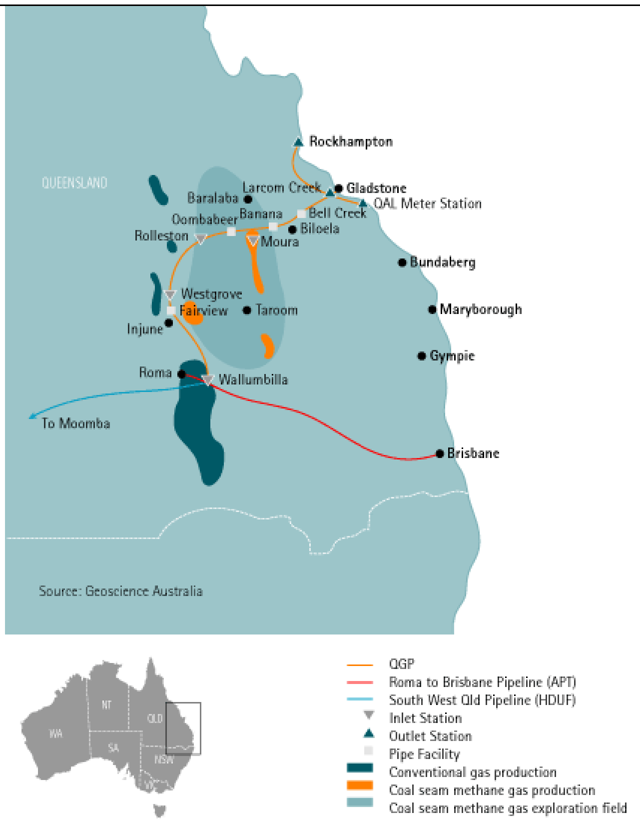
In order to supply the proposed expansion at Comalco's Yarwun refinery (22.8 PJ/a), Jemena is undertaking a significant expansion of the QGP that will increase capacity to 52 PJ/a by April 2010.

This section provides information on the costs associated with transporting gas to the relevant markets via the existing Queensland Gas Pipeline (QGP), owned and operated by Jemena Limited.

5.1 Queensland Gas Pipeline (QGP)

Commissioned in 1990, the Queensland Gas Pipeline (QGP) is a 627 km, 324 mm/219 mm pipeline transporting natural gas between Wallumbilla in the west and Gladstone and Rockhampton on the central Queensland coast. The pipeline creates a strategic infrastructure link between gas supply and demand in the Queensland gas market. It connects most supply sources in Queensland, including Northern and Southern Denison Trough, Surat Basin and Bowen Basin CSG supplies directly to markets in Gladstone and Rockhampton. The location of the QGP is shown in Figure 17.

Figure 17 **Location of Queensland Gas Pipeline**



Data source: Alinta Infrastructure Holdings

The Queensland Gas Pipeline is comprised of three sections:

- **Wallumbilla to Gladstone**: 514.4 km of 323.9 mm O.D. Class 600 transmission pipeline. This line has an inlet pressure operating range of 5000 - 10200 kPa. Normal operating pressure range is 8,200 – 9,500 kPa as measured at Rolleston Meter Station
- **Gladstone City Main**: 16.1 km of 323.9 mm O.D. Class 300 pipeline and associated laterals from Gladstone City Gate Station to QAL Meter Station. The normal operating pressure of this pipeline segment is approximately 2,700 kPa
- **Larcom Creek – Rockhampton**: 96.7 km of 219.0 mm O.D. Class 600 pipeline from Larcom Creek Meter Station (the tee off from the main line) to Rockhampton City Gate Station. Normal operating pressure for the Rockhampton Branch Pipeline is approximately 4,500 kPa.

The Pipeline currently has five gas receipt stations:

- **Wallumbilla**: Wallumbilla Station (K.P. 0.00). This receipt point services the Surat, Cooper & Eromanga Basins and provides interconnection with the Roma to Brisbane and South West Queensland (Ballera to Wallumbilla) pipelines.

- **Fairview**: The Fairview lateral ties into the main line at KP 134.5 (Ridgelands Scraper Station). There is 25.6 km of 200mm NB Class 900 pipeline between the Fairview meter station and the main line.
- **Westgrove**: Westgrove Station (K.P. 154.04) is a single producer receipt point servicing the South Denison Trough.
- **Rolleston**: Rolleston Station (K.P. 243.45) is a single producer Receipt Point servicing the North Denison Trough.
- **Moura**: Moura Station (K.P. 360.71) is a dual producer Receipt Point, servicing the CSG production from the Moura mine and Dawson Valley areas of the southern Bowen Basin.

Jemena currently owns and operates seven dedicated delivery stations on the pipeline. An additional three delivery points are owned and operated by Origin Energy Ltd, two located in Rockhampton and one in Gladstone.

The seven Jemena delivery points are:

- **ORICA Australia Operations Pty Ltd**: The ORICA Delivery Point is located downstream of the Gladstone City Gate at K.P. 516.26
- **Queensland Alumina Limited [QAL]**: The QAL delivery station is located at the end of the Gladstone City Main at K.P. 530.41. It acts as a dual delivery station servicing both the QAL and Boyne smelters
- **Boyne Smelter Metering Skid**: (K.P. 530.41)
- **AMC**: (K.P. 514.716)
- **TICOR**: (K.P. 516.25) - disused since the closure of the Ticor plant
- **SUNCOR**: (K.P. 519.08) - disused
- **Queensland Magnesia (Operations) Pty Ltd [QMag]**: The QMag delivery site is located within the Rockhampton City Gate Station at the end of the RBL (96.7 km from Larcom Creek).

5.1.1 Current transportation contracts

The QGP has current contracts for around 20 PJ/a of physical transport (66 TJ/d of capacity) and transports gas to major industrial facilities including those operated by QAL, Orica, QMAG, and Boyne Smelters Ltd. It also supplies gas to Origin Energy for on-selling to domestic, commercial and residential users.

In November 2003, QAL announced a 15-year gas supply agreement with Origin Energy for supply of between 11 and 13 PJ/a of gas for a period of 15 years commencing in 2006. This was followed by a renewal of QAL's transportation agreement which secures around 13 PJ/a of firm forward haul revenue to Jemena for over 10 years to 31 December 2016.[5]

QAL is also understood to be considering the possibility of constructing a co-generation facility[6], which would use up to 12 PJ/a of gas. Alumina refineries are ideal hosts for cogeneration, as they use substantial amounts of steam as well as electricity. However, given the demand for steam is significantly greater than electricity, the economics of cogeneration at the alumina plants will depend upon the prevailing wholesale electricity prices for power exported to the grid as well as fuel cost into the co-generation plant. Gladstone is currently oversupplied with generating plant and generators receive less than the prevailing pool price as the marginal loss factor is around 0.92. Alternatively, a cogeneration plant could minimise power exports and raise additional steam.

Most of the market for QGP is assured through long term firm forward contracts until 2016. It is also well located to transport CSG from a number of projects close to industrial markets in southern and central Queensland (and is already shipping CSG from the Fairview, Moura and Dawson Valley projects).

5.1.2 Pipeline capacity and flow

The pipeline is presently operating close to its current capacity—according to former owner Alinta Infrastructure Holdings (AIH) there are currently firm contracts in place for 66 TJ/day, with only 4 TJ/day of uncontracted capacity available.

From April 2010, an expansion of the pipeline will provide new users with access to additional capacity.[7] However most of this additional capacity will be contractually committed to service the expanded gas requirements of Comalco for the Yarwun Stage 2 project. Further expansion may be undertaken to meet the needs of new customers willing to commit to take additional capacity.

The expansion involves both looping and compression—at a cost of A$112m—to increase capacity to 52 PJ/a by April 2010. The additional compressors are located at Rolleston and Banana, and pipeline looping will occur from Moura to Bell Creek.

---

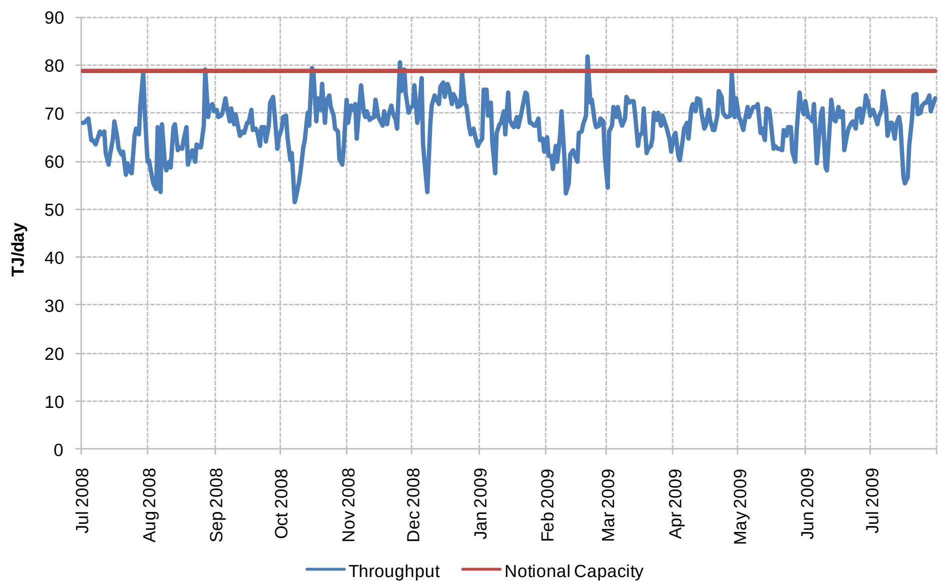
[5] This signing of this contract represents a marginal increase in both gas throughput and revenues compared to forecasts incorporated in AIH's August 2005 Product Disclosure Statement and Prospectus.

[6] In August 2006 QAL applied for a generation license under the Electricity Act 1994 for a 122.5 MW gas-fired cogeneration unit.

[7] Jemena website, accessed 21 September 2009

Figure 18 shows the historical flows on the QGP over 2008-09. Over the year, the QGP shipped a total of 24.7 PJ, at an average rate of 67.6 TJ/day. Based on its reported current capacity of 79 TJ/day, the system average load factor for the year was around 86%.

Figure 18 **QGP throughput for financial year 2008-09**



Data source :ACIL Tasman based on Gas Market Bulletin Board data

5.1.3 Transportation tariffs

Different tariffs apply for existing shippers with transportation contracts in place prior to the introduction of the *National Gas Law* (NGL) on 1 July 2008, and for new users after that date.

Pre-NGL contracts

For transportation contracts in place prior to the introduction of the NGL on 1 July 2008, tariffs for firm forward haul transportation consist of:

- a capacity reservation charge equal to the capacity reservation rate multiplied by the relevant user's MDQ. As of 1 July 2006 the capacity reservation rate was A$0.58/GJ[8]
- a distance reservation charge equal to the distance reservation rate multiplied by the distance component multiplied by the relevant user's MDQ. As of 1 July 2006 the distance reservation rate was A$0.000943/GJ/km (A$0.000660/GJ/km after expansion date).

[8] Tariff escalation provisions allow for an increase to the capacity reservation rate of $0.04 on 1 July 2011, 2016, 2021, 2026 and 2031.

For pre-NGL contracts, charges on the pipeline are limited by a rate cap of A$0.795/GJ. The rate cap declines to A$0.71/GJ after the Expansion Date, which is the date upon which the Service Provider first commences transportation Services under Access Agreements providing for firm Contracted Capacity for Firm Forward Haul Services of 25 PJ or more on an annualised basis. The capacity expansion scheduled for completion in April 2010 will trigger the reduction in tariff rate for pre-NGL shippers.

Table 14 **QGP transportation tariffs for pre-NGL contracts**

	Units	Before expansion date	After expansion date
Capacity reservation rate	A$/GJ/MDQ	0.58	0.58
Distance reservation rate	A$/GJ/MDQ/km	0.000943	0.00066
Rate cap	A$/GJ/MDQ	0.795	0.71
80% LF tariff cap	A$/GJ	0.994	0.888

Note: Tariffs are for firm forward haul service, as at July 2006.
Data source: Jemena; ACIL Tasman analysis

The rate cap currently limits the firm forward haul service to a tariff of A$0.795/GJ of MDQ reserved. As a result, all pre-NGL contracts relating to haulage over distances less than about 228 km pay a charge below the cap rate.

Post-NGL shippers

Following the introduction of the NGL on 1 July 2008 (replacing the GPAL and National Code) Jemena accepted new transitional arrangements proposed by the Queensland Government under which the QGP will be an unregulated pipeline for at least three years. However, Jemena has continued to provide a voluntary non-discriminatory pipeline access undertaking for parties wishing to contract for services on the QGP.[9]

The tariffs offered to post-NGL shippers are set out in Table 15. A capacity charge of $0.795/GJ (as at 1 July 2008) applies for firm forward haulage. This tariff is indexed at CPI on 1 January each year. The tariff is calculated for the entire pipeline system on a "postage-stamp" basis: the distance rate with cap no longer applies. The firm forward haulage rate for post-NGL shippers is not subject to the volume-triggered rate reduction that applies to pre-NGL contracts.

[9] Jemena website, accessed 21 September 2009

Table 15 **QGP transportation tariffs for post-NGL shippers**

Tariff Schedule – Queensland Gas Pipeline

Effective from 1 July 2008

Firm Gas Transportation Service

Capacity Tranche	Currently Available	Available From	Available Until	Tariff ($/GJ)	Comments
0 - 66.8 TJ/d	0	n/a	n/a	n/a	Fully contracted
66.8 - 79.0 TJ/d	12.2 TJ/d	now	1/04/2010	0.795	Available

As Available Gas Transportation Service

Delivery Point \ Receipt Point	Wallumbilla $/GJ	Gooimbah Lacerta $/GJ	Fairview Westgrove $/GJ	Rolleston $/GJ	Moura Inlet $/GJ
Rockhampton	1.4258	1.3150	1.2974	1.1388	1.0005
Gladstone	1.3503	1.2395	1.2219	1.0633	0.9250
Yarwun	1.3313	1.2205	1.2029	1.0443	0.9060
Moura	1.1503	1.0395	1.0219	0.8633	
Wallumbilla		Refer Backhaul	Refer Backhaul	Refer Backhaul	Refer Backhaul

Backhaul Service

Delivery Point \ Receipt Point	Gooimbah Lacerta $/GJ	Fairview Westgrove $/GJ	Rolleston $/GJ	Moura Inlet $/GJ
Wallumbilla	0.4600	0.4600	0.4600	0.4600

Authorised Overrun Rate	130% x Capacity Reservation Rate
Unauthorised Overrun Rate	150% x Capacity Reservation Rate, As Avaialble Rate and Backhaul Rate
Unauthorised Overrun OFO Rate	300% x Capacity Reservation Rate, As Avaialble Rate and Backhaul Rate
Imbalance Rate	30% x Capacity Reservation Rate, As Avaialble Rate and Backhaul Rate
Daily Variance Rate	120% x Capacity Reservation Rate, As Avaialble Rate and Backhaul Rate
Minimum Service Charge - (for As Available and Backhaul Services)	$1,231 /month
Tariff Adjustment	CPI (All Groups Weighted Average of Eight Capital Cities) on 1 January each year

Data source: Jemena

6 CSG LNG transportation cost assessment

[Confidential]

7 Costs for Surat/Bowen Basin producers to access other pipelines

Chapter Summary

In order to understand the market options that may be available to producers in the Surat/Bowen Basin, this chapter considers what other existing pipelines could be accessed, and at what cost. Two hypothetical gas producers are considered:

- Surat/Bowen Producer A, located 50km northeast of Wallumbilla, with an assumed production capability of 10 PJ/a
- Surat Producer B, located 25 km south of the Roma-Brisbane Pipeline mid-line, with an assumed production capability of 5 PJ/a

The costs for these producers to access different markets in Eastern Australia are made up of two components:

- Costs associated with tying in to the existing gas transmission network, including costs of the lateral pipelines and facilities costs for compression, metering etc (note that the latter costs are likely to be similar irrespective of what pipeline the producers tie in to).
- Tariff charges for transportation on existing third-party transmission lines.

For the two model cases, the tie in costs range from A$9.75 to A$27.5 million, with a corresponding unit tariff range of A$0.20 to A$0.28/GJ. Costs for transportation on third-party pipelines vary widely, depending on target market location. The total estimated range of third-party tariff costs is from A$0.74/GJ for transport to Brisbane, up to A$2.39/GJ for transport to Mt Isa.

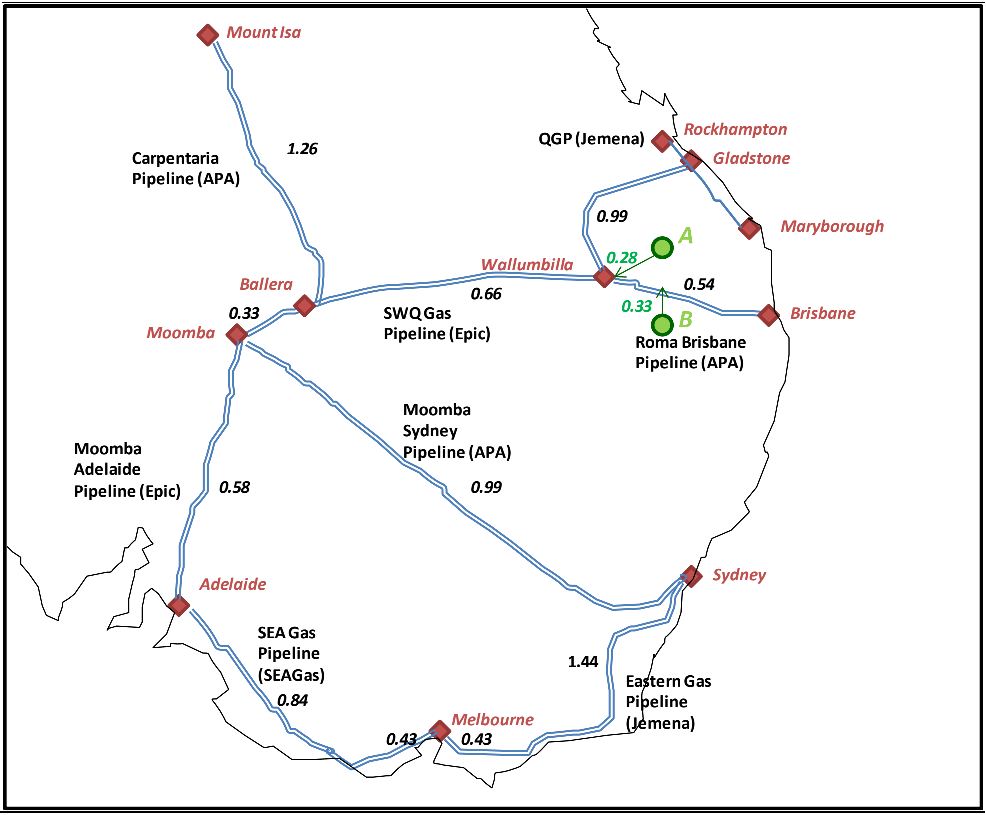
The analysis highlights the fact that CSG producers in the Surat and southern Bowen Basins will generally have options to pursue markets throughout Eastern Australia via the existing gas transmission pipeline network.

In order to understand the market options that may be available to producers in the Surat/Bowen Basin, it is relevant to consider what other existing pipelines could be accessed, and at what cost. For the purpose of this exercise, we consider two hypothetical gas producers:

- Surat/Bowen Producer A, located 50km northeast of Wallumbilla, with an assumed production capability of 10 PJ/a
- Surat Producer B, located 25 km south of the Roma-Brisbane Pipeline mid-line, with an assumed production capability of 5 PJ/a

Figure 19 shows the locations of these two hypothetical gas producers relative to the existing gas transmission network. Figure 19 also shows the current estimated transmission tariffs at an average 80% load factor for transportation on the various pipelines.

Figure 19 **Transmission pipeline alternatives to market for Surat/Bowen CSG producers**



Note: Indicative tariffs (A$/GJ, real 2009) for 80% load factor gas supply

Source: ACIL Tasman GMG Australia modelling

The costs for these producers to access different markets in Eastern Australia are made up of two components:

- Costs associated with tying in to the existing gas transmission network, including costs of the lateral pipelines and facilities costs for compression, metering etc (note that the latter costs are likely to be similar irrespective of what pipeline the producers tie in to).
- Tariff charges for transportation on existing third-party transmission lines.

Table 16 shows the assumptions and calculations relating to our estimates of the tie-in costs for the two hypothetical CSG producers.

Table 16 **Estimated costs for Surat/Bowen producers to tie in to existing pipelines**

	Surat/Bowen Producer A	Surat Producer B
Distance to tie in(km)	50	25
Annual gas sales (PJ)	10	5
Tie-in pipe diameter (inches)	10	6
Tie in costs		
Pipeline (A$M)	22.5	6.75
Metering etc (A$M)	5	3
Total (A$M)	27.5	9.75
Annual revenue requirement @ 10% (A$M)	2.75	0.98
Unit tariff A$/GJ	0.28	0.20

Data source: ACIL Tasman analysis

Table 17 then combines the tie-in costs with the additive pipeline tariffs to provide estimates of the total costs for the two hypothetical CSG producers to ship gas to major market centres in Eastern Australia.

Table 17 **Estimated transport costs from Surat/Bowen CSG cases to major Eastern Australian markets using existing pipelines (A$/GJ)**

Target Market	Surat/Bowen Producer A			Surat Producer B		
	Tie-in Cost	Third Party Tariffs	**Total**	Tie-in Cost	Third Party Tariffs	**Total**
Gladstone	$0.28	$0.99	**$1.27**	$0.20	$1.26	**$1.46**
Brisbane	$0.28	$0.54	**$0.82**	$0.20	$0.54	**$0.74**
Mount Isa	$0.28	$1.92	**$2.20**	$0.20	$2.19	**$2.39**
Adelaide	$0.28	$1.57	**$1.85**	$0.20	$1.84	**$2.04**
Sydney	$0.28	$1.98	**$2.26**	$0.20	$2.25	**$2.45**

Data source: ACIL Tasman GMG Australia model and analysis

The analysis highlights the fact that CSG producers in the Surat and southern Bowen Basins will generally have options to pursue markets throughout Eastern Australia via the existing gas transmission pipeline network. Unit costs to tie in to the pipeline network will be dependent on the location of the gas fields relative to existing transport facilities, and on the volume of gas sales over which the fixed costs associated with tie-in can be allocated. Large resources close to existing facilities are likely to face lower unit costs than small fields located far from existing facilities. However, the analysis presented demonstrates that tie-in costs are likely to be relatively low—less than A$0.50/GJ—for a range of realistic development scenarios.

Another consideration is that not all pipelines will necessarily have spare capacity available at the time when producers are seeking to establish markets for their gas. Most transmission pipeline owners nowadays will only expand system capacity if there are customers willing to commit to take and pay for the incremental capacity under long term gas transportation agreements. As a result, many pipelines operate with little or no uncontracted firm capacity available. They may offer capacity on an "as available" or interruptible basis, and will generally have a queuing system so that prospective new shippers can register their interest in taking up new capacity, which the pipeline owner will provide when sufficient firm demand is established to underpin the next efficient tranche of developable capacity. As a result, a producer looking to lock in a new gas buyer may face some uncertainty over the timing of transport availability. That uncertainty is likely to increase as distance to the prospective market increases, and with the number of pipeline segments involved particularly where there is more than one pipeline owner in the supply chain.

Nevertheless, owners of the transmission pipelines illustrated in Figure 19 are all in the business of providing gas transportation services. They are commercially incentivised to expand system capacity to meet the needs of prospective shippers that willing to commit to take capacity, provided only that the transport volumes being sought are large enough to support efficiently sized expansion of capacity.

A Appendix 1 – Curriculum Vitae

Paul Balfe, Executive Director

Paul Balfe is a director of ACIL Tasman and has overall responsibility for the firm's gas business.

Mr Balfe graduated from the University of Queensland (B.Sc. (Hons 1) in Geology and Mineralogy 1976; MBA 1988). He has some 33 years experience working in the mining and energy sector in Australia as a geologist, government administrator and economics and policy consultant. He commenced his career working as a petroleum and coal geologist with the Geological Survey of Queensland, and subsequently held various managerial roles in energy resource development in the Queensland Department of Mines & Energy (QDME).

In 1995 Mr Balfe left the position of Director of Energy in QDME to join ACIL Economics & Policy, a national firm with a substantial consultancy practice in the area of energy markets and energy policy. ACIL Economics & Policy subsequently changed its name and merged with another company to form ACIL Tasman.

As the Executive Director responsible for ACIL Tasman's gas business, Mr Balfe has guided the development and commercialisation of ACIL Tasman's *GasMark* model and its application to strategic and policy analysis throughout Australia and in New Zealand. He provides a range of analytical and advisory services to companies, government agencies and industry associations, particularly in the gas, electricity and resources sector. He has worked extensively on gas industry matters, particularly gas policy reform issues; gas market analysis; gas pipeline developments, acquisitions and disposals; and gas project commercial analysis. He was closely involved in commercial and regulatory negotiations for the proposed PNG Gas Pipeline, and has worked extensively in the Queensland coal seam gas (CSG) industry as an adviser to both government and corporate sector clients on regulatory, technical, economic and commercial aspects of CSG development.

Owen Kelp, Senior Consultant

Owen Kelp is a Senior Consultant with ACIL Tasman specialising in electricity and gas markets. Owen has worked extensively on energy industry matters and across a broad range of assignments including upstream conventional and coal seam methane economics; market demand, supply and price forecasting studies; strategic reviews; transmission and distribution networks (project evaluation, throughput forecasts, asset sales and due diligence work); project evaluation (financial modelling, market studies and economic benefits); regulatory and policy change impact studies. Over the last eight years Owen has managed more than 50 energy industry assignments.

He has extensive modelling capability using various software packages and programming languages as well as practical experience with operations research methods including linear programming and optimisation. He also has a good theoretical knowledge of financial markets and instruments. Owen has been principally responsible for the development and maintenance of a number of ACIL Tasman energy market models, in particular:

- *GasMark Global* – ACIL Tasman's global model for gas trade for both LNG and pipeline gas
- *GasMark* – ACIL Tasman's regional model of the interconnected Australian gas market
- *GasMark New Zealand* – supply demand model for the New Zealand system
- *PowerMark* – detailed model of the National Electricity Market used for price forecasting and asset due diligence
- *PowerMark WA* – detailed model of the Western Australian electricity market.

Owen holds a Bachelor of Business (Economics and Finance) from Queensland University of Technology and a Graduate Diploma of Applied Finance and Investment from the Financial Services Institute of Australasia (FINSIA).

Peter Crittall, Senior Associate

Peter Crittall is a Senior Associate energy advisor with ACIL Tasman, based in the Brisbane office. With a BSc (Hons) and MBA qualifications, Peter's area of specialisation is energy economics.

Peter has been a management consultant specialising in the resources sector for fifteen years. He has worked with a wide range of clients in both the Government and private sectors. Peter has extensive experience in the energy sector, included detailed understanding of the interaction between gas and electricity markets. He was previously Queensland Manager for the energy consulting firm, McLennan Magasanik Associates.

Martin Pavelka, Analyst

Martin Pavelka is a research analyst at ACIL Tasman based in the Brisbane office. He graduated with a Master of Commerce and Honours in Economics from the University of Queensland. Martin's area of specialisation is data compilation, analysis and modelling.

Prior to joining ACIL Tasman, he was responsible for monitoring, estimating and forecasting state, regional and industry growth as an Economist with the Queensland Treasury. In this role, he was also involved in the development and implementation of econometric and CGE models. At ACIL Tasman Martin assists senior consultants on projects in the areas of electricity and gas market analysis. Martin has developed advanced skills in data analysis using econometrics and has gained in depth knowledge of domestic and international data relating to the estimation and monitoring of growth components of the economy. He has applied his econometric modelling skills to the development of an interregional forecasting model of the Queensland economy and its components. Martin also has experience in using microeconomic modelling tools through his involvement in a range of projects, particularly in the energy and water sectors.

B GMG Australia gas model

The GasMark Global (GMG) Australia model is a generic gas modelling platform developed by ACIL Tasman which has the flexibility to represent the unique characteristics of gas markets across the globe. Its potential applications cover a broad scope— from global LNG trade, through to intra-country and regional market analysis.

Settlement

At its core, GMG is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[10], consists of three terms:

- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

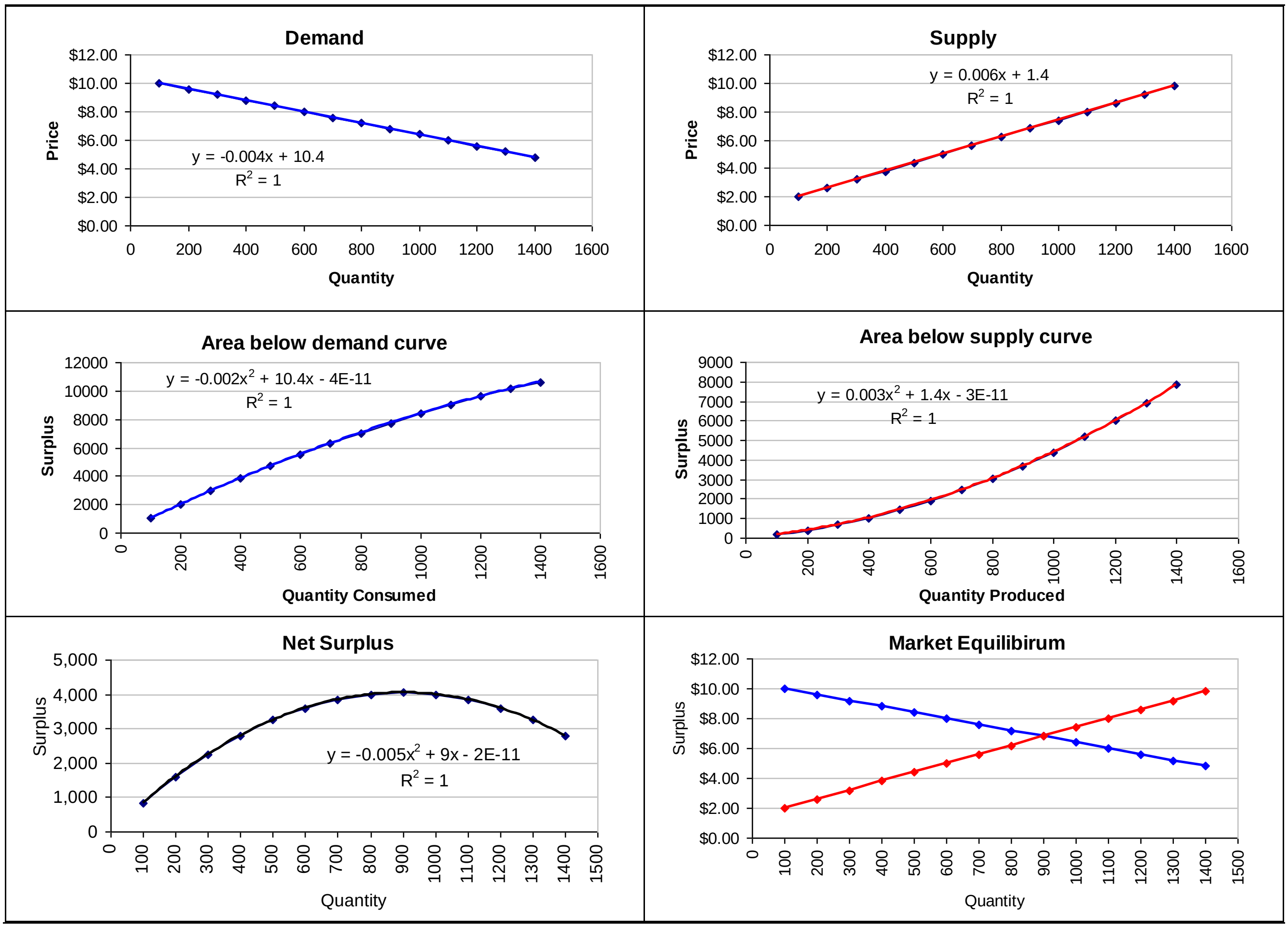
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

Figure 20 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure 20 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure 20 show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the

[10] The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

Figure 20 **Simplified example of market equilibrium and settlement process**



Data source: ACIL Tasman

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world. Examples include:

- Gas Pipeline Competition Model (GPCM®) developed by RBAC Inc energy industry forecasting systems in the USA.
- Market Builder from Altos Partners, another US-based energy market analysis company.

Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG can be categorised as follows:

- **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.
- **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual gas demand, price tolerance and price elasticity of demand (that is, the amount by which demand will increase or decrease depending on the price at which gas can be delivered), and load factor (defined as the ratio between average and maximum daily quantity requirements).
- **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity, system average load factor (which is relevant to determination of the effective annual throughput capability given assumptions regarding short-term [daily] capacity limits) and tariffs.

- **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.