

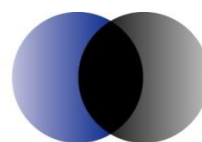


Gas Demand Study

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

Prepared for Ashurst on behalf of GLNG

Public Version Final Report
1 March 2013



ACIL Tasman

Economics Policy Strategy

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Executive summary

ACIL Tasman was engaged by Ashurst on behalf of GLNG Operations Pty Ltd to undertake a market study in support of GLNG's planned application under s.151(3) of the *National Gas Law* 2008 for a 15-year no-coverage determination that will exempt the GLNG Gas Transmission Pipeline from being a covered pipeline for purposes of third party access. The GLNG Gas Transmission Pipeline will carry coal seam gas (CSG) from the production fields in the Surat and Bowen Basins of Central Queensland to the LNG liquefaction plant on Curtis Island, near Gladstone.

Downstream markets

The main downstream gas market potentially serviced by the GLNG Gas Transmission 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 GLNG Gas Transmission 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, including two other projects (Queensland Curtis LNG Project and Australia Pacific LNG Project) that have reached final investment decision. These projects will see further dedicated pipeline connections linking the CSG fields of the Surat and Bowen Basins to Gladstone.

Gas demand in the downstream markets

In 2010-11 levels of gas consumption in the relevant downstream markets were estimated to be as follows:

- Gladstone – 37.9 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 50 PJ/a by 2015. After this date, there is an apparent levelling out of demand

at Gladstone. However, this is likely to be an artefact of the planning horizon for large industrial projects of the type typical of the Gladstone area, 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 assumptions would be purely speculative given the lack of specific long term development proposals.

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

Gas prices in the downstream markets

Wholesale prices for gas under long term contracts delivered at Gladstone and Rockhampton are presently estimated to be in the range A\$4.00 to A\$5.50/GJ (real 2011 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 Cleaner Energy Future carbon tax/emission trading scheme (CEF), Large-Scale Renewable Energy Target (LRET), and the Queensland Government Domestic Market Obligation.

CEF

The CEF carbon pricing package is directionally 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. CEF will also result in higher sustainable gas prices because of improved competitiveness with coal on a carbon-inclusive basis. CEF is estimated to increase the wholesale price of gas by as much as A\$1.00/GJ for each A\$30/t CO₂e carbon price.

SRES and LRET

The Small-scale Renewable Energy Scheme (SRES) and Large-scale Renewable Energy Target (LRET) will tend to suppress consumption of gas for power generation, but LRET in particular will drive a need for additional open-cycle gas-fired peaking plant as back-up to unreliable wind generation. Installation of

solar photovoltaic panels under the SRES is resulting in some reduction in wholesale electricity demand growth throughout the National Electricity Market (NEM). The LRET scheme is unlikely to have a great effect on gas demand in the Gladstone region because there is a lack of good quality wind generation sites in Central Queensland.

Domestic Market Obligation

The Queensland Government during 2009 considered the introduction of a “domestic market obligation” requiring LNG project proponents to set aside up to 20% of their CSG reserves for local domestic purposes. Even for a single train development with a total LNG feed gas requirement of around 265 PJ/a, such a policy would have required dedication of up to 1,060 PJ of additional reserves, sufficient to support 53 PJ/a of domestic production over a period of 20 years, or around one-quarter of total current consumption of gas in Queensland. Such a policy would have increased the risks for the GLNG 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 if required. The need for such a policy was monitored by the Queensland Gas Commissioner with formal reviews undertaken annually. In April 2012 it was announced that Queensland Gasfields Commission would in future fulfil this role.

Gas market modelling

The gas market modelling presented in this report was undertaken in April 2012, prior to APLNG taking a final investment decision on its second train.

The report sets out the results of modelling two LNG development scenarios: a “Project Case” involving development of the first two LNG trains proposed by GLNG together with the currently committed two trains at QCLNG and one further train at APLNG; and an “Industry Case” that includes two GLNG trains plus three trains at QCLNG; two trains at APLNG and two trains at Arrow LNG for a total of nine LNG trains with annual production capacity of around 36 Mtpa.

Both scenarios show that anticipated gas demand in the downstream markets is substantially satisfied throughout the modelling period (to 2030) without utilisation of the GLNG Gas Transmission Pipeline for carriage of gas to domestic markets.

The model was configured so that all gas delivered into the Gladstone domestic market is transported via the existing Queensland Gas Pipeline (QGP), rather than the GLNG Gas Transmission Pipeline. No gas is delivered to the Gladstone domestic market via the GLNG Gas Transmission Pipeline.

Modelling of gas prices under the two scenarios shows that real prices remain relatively flat in the short term, reflecting the ramp up of CSG production in the region. Prices then rise from a low of around A\$4.00/GJ delivered at Gladstone prior to commissioning of the LNG facilities to around A\$6.90/GJ (real, 2011) by 2020 and \$8.90/GJ by 2030 in the “Project Case”. The corresponding prices in the “Industry Case” are around A\$7.20/GJ (real, 2011) by 2020 and \$9.70/GJ by 2030.

CSG LNG Projects

Since early 2007, at least six LNG projects based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been proposed. Four projects are being actively pursued, including three which have reached Final Investment Decision and are now under construction. Six LNG trains with total nominal capacity of 25.3 Mtpa have now been committed. Total installed capacity could reach almost 60 Mtpa if the projects are developed to their full announced potential sizes.

The following are the most advanced project proposals:

- Queensland Curtis LNG (BG Group/CNOOC): two LNG trains initially, each with nominal capacity of 4.25 Mtpa, with the first on line late 2014, second during 2015. A third train, of similar size, is proposed but timing is uncertain.
- Gladstone LNG (Santos/Petronas/Total/KOGAS): First two trains (total 7.8 Mtpa) committed with first LNG from early 2015; potential for three trains up to 10 Mtpa.
- APLNG (Origin/ConocoPhillips/PetroChina): First train of 4.5 Mtpa committed July 2011 and under construction; second train (also 4.5 Mtpa) committed July 2012. Targeting first production in 2015; with second train commencing shipments in 2016. Announced potential for up to four LNG trains.
- Arrow LNG (Shell/Arrow, Sinopec) working toward a final investment decision for one or two trains (each 4 Mtpa) during 2013. First gas possible by 2017. Announced potential for up to four LNG trains.

Small CSG producer assessment

Chapter 4 considers the question whether other CSG producers in the vicinity of the proposed GLNG Gas Transmission 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 has identified three companies not currently involved in LNG proposals that have CSG or conventional gas resources or exploration areas prospective for CSG located within 100 km of the GLNG Gas Transmission Pipeline. Two of these companies are already producing gas from these areas and have arrangements in place with existing transmission pipeline operators to transport the gas to their customers in Central Queensland.

None of these resource and prospect holders are likely to find that access to the GLNG Gas Transmission Pipeline would offer a commercially attractive means of reaching prospective customers compared to the alternatives already available and in use. This is principally because there is no advantage in terms of tie-in distances, given that most prospects are equal distance from the QGP (via the Dawson Valley Pipeline) and the cost-reflective tariff on the GLNG Gas Transmission Pipeline would be no lower than current commercial tariffs on QGP.

Other factors mitigating against third party use of the GLNG Gas Transmission 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 likelihood that the GLNG Gas Transmission 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 users with contracts entered into prior to introduction of the National Gas Law, charges on the pipeline are currently limited by a rate cap of A\$0.795/GJ of capacity reserved (now reduced to A\$0.71/GJ after 2010 capacity expansion). For new users, the charge for firm capacity is currently A\$0.8993/GJ (as at 1 January 2012). Tariffs are indexed by CPI on 1 January each year. No more than 5 TJ/d of firm capacity is currently available; additional firm capacity would require further expansion of the pipeline system.

As Available Transport Service (interruptible) is offered at rates varying according to receipt point and delivery point. For full line transport from Wallumbilla to Gladstone, the As Available haulage rate is currently about \$1.53/GJ for each unit of gas delivered.

CSG LNG transportation cost assessment

Chapter 6 provides an assessment of the average real and levelised tariffs that would be required to yield a commercial rate of return on the proposed GLNG Gas Transmission Pipeline, operated on a standalone basis. The analysis considers both the two-train “Project Case” (free-flow) and a 3-train sensitivity (with mid-line compression), and considers tariffs for a project life of 25 years. For the 2-train case, the average real tariff is estimated to be \$1.27/GJ of capacity booked, or \$1.64/GJ on a levelised basis. For the 3-train case, the corresponding tariffs are \$1.15/GJ and \$1.50/GJ respectively.

A 2% change in the discount rate has an impact of around \$0.25/GJ on the levelised tariff under the 2-train case. A 10% change in pipeline capital cost has an impact of around A\$0.07/GJ on the levelised tariff.

Costs to construct a tie-in from the GLNG Gas Transmission Pipeline to the Gladstone City Gate would depend on the length of the required lateral as well as the required flow rate across the tie-in. Tie-in facility costs are estimated to be about \$5m. The cost of a lateral pipeline connection from GLNG Gas Transmission Pipeline to Gladstone City Gate is estimated at \$0.5 million for a one-kilometre tie-in with a 10” diameter, leading to an all-up tie-in cost of around \$5.5 million. Increasing the length of the required lateral from GLNG Gas Transmission Pipeline to Gladstone City Gate to 10 km would result in the overall capital cost of the tie-in increasing to \$10 million.

Costs to access other pipelines

In order to understand the market options that may be available to producers in the Surat/Bowen Basin, Chapter 7 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
- Western Surat Producer B, located 25 km west of the QGP, 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:



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- Costs associated with tying in to the existing gas transmission network, including costs of the lateral pipelines and facilities costs for compression, metering etc.
- Tariff charges for transportation on existing third-party transmission lines.

For the two model cases, the tie in costs range from \$10.29 to \$28.9 million, with a corresponding unit tariff range of \$0.35 to \$0.38/GJ excluding compression costs (which are likely to be similar for delivery of gas into the GLNG Gas Transmission Pipeline or QGP). 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 \$0.95/GJ for transport to Brisbane via the Wallumbilla hub, up to \$2.94 /GJ for transport to Sydney.

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 GLNG to undertake this market study in support of GLNG'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 GLNG project; explains the scope of the market study; and sets out ACIL Tasman's qualifications to prepare the study.

GLNG, a joint venture between Santos, PETRONAS, Total and KOGAS, plans to build a 420km gas transmission pipeline from its CSG production area located in the vicinity of the towns of Roma, Wallumbilla, Injune and Rolleston to its proposed Liquefied Natural Gas facility based on Curtis Island near Gladstone. ACIL Tasman was engaged by Blake Dawson (now Ashurst Australia) on behalf of GLNG 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 GLNG 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 GLNG Project

The GLNG 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 GLNG Project is a fully integrated LNG project, which comprises three inter-related and inter-dependent components:

- the Gas Fields;
- the Pipeline; and
- the LNG Facility.

CSG extracted at the Gas Fields will be transported through a network of underground flowlines to centralised hub stations for compression and dehydration and then from those hub stations to the Pipeline. GLNG will also

utilise GLNG's existing Comet Ridge to Wallumbilla Pipeline (the "CRWP"), which is proposed to be looped and extended, to facilitate the transportation of gas from the Wallumbilla and Roma fields (forming part of the Gas Fields) to the Pipeline, the transportation of gas to and from GLNG's underground reservoirs at Roma (the "Roma Underground Gas Storage Facility") and for additional flexibility during the Gas Fields ramp up stage. The gas will then be transported through the Pipeline to the LNG Facility for liquefaction and export.

Other gas (both conventional and coal seam) will also be acquired from third parties. It is highly likely that third party conventional gas will need to be processed (beyond AS 4564 Australian Standard Specification for General Purpose Natural Gas) prior to delivery to the Pipeline to ensure it meets the LNG Facility gas specification. GLNG will likely also need to process or manage the gas specification of third party coal seam gas and any gas from the Gas Fields temporarily stored in GLNG's underground reservoirs. Epic Energy Queensland Pty Limited has agreed to supply to GLNG compression and associated services at the Wallumbilla gas hub to assist GLNG in managing gas specification requirements. GLNG is also currently considering construction of a gas treatment facility near Wallumbilla (the "**Treatment Facility**") if required to treat third party gas and/or gas temporarily stored in GLNG's underground reservoirs to ensure it meets the LNG Facility gas specification (discussed below). Any gas processed by the Treatment Facility would be transported through the CRWP and then through the Pipeline to the LNG Facility.

1.1.1 Gas Fields

CSG is essentially methane (natural) gas extracted at low pressure from coal seams. CSG produced in Australia typically has a high methane content (about 98%). In the past, natural gas was more often extracted from sandstone, generally at greater depths and higher pressure. CSG is formed as part of the same natural processes that produce coal over millions of years. The coal seams from which GLNG is producing are typically between 200 and 1,200 metres below the surface. The coal in these seams is naturally filled with gas and water, which keeps the gas trapped in the coal.

Santos began CSG exploration and production in the Surat Basin in 2002. The GLNG Upstream Entities' share of the CSG currently being produced at the Gas Fields is sold by the GLNG Upstream Entities domestically to customers at Gladstone and, via the Wallumbilla hub, to markets in Mount Isa, South Australia and New South Wales.

The development of coal seam gas fields involves the drilling of exploration and production wells down into the coal seam. Water is pumped from the coal

seam, reducing the pressure within the coal and allowing the gas to be released. The gas flows through coal cleats (small fractures or joints in the coal) toward the well bore. If the release of gas is not sufficient for commercial production, then processes such as hydraulic fracturing may be used to open the coal seams and increase the rate of gas and water production. The average well can produce for up to 20 years, but the amount of gas depends on the thickness of the coal, gas content and the depth of the coal seam. A typical CSG well produces mainly water for around 12 months as water pressure is reduced, which CSG flow rates gradually increasing and then remain steady for a number of years.

It is costly to stop producing CSG from a well once it has been de-watered as water may re-enter the well. This fact, combined with the number of wells required for CSG to LNG production (which generally is far in excess of the number of wells required for LNG production from conventional gas fields) means that sudden changes in the demand for CSG from the LNG Facility will impose significant costs on the operation of the Gas Fields. GLNG will use the Pipeline as one of the means by which it will manage that equilibrium of production and supply.

The Gas Fields are located at Fairview, Roma, Arcadia, Comet Ridge and Scotia. The existing Gas Fields at each of these locations, which are at various stages of development, will be further developed for the GLNG Project with GLNG currently having approval to develop up to 2,650 exploration and production wells in the Gas Fields over the life of the GLNG Project. GLNG also has commenced a further environmental impact statement (the "EIS") process for the development of additional wells within the Gas Fields area (beyond the well numbers already approved through the initial EIS process for the GLNG Project).

The first and second trains of the LNG Facility will be supplied by gas produced from existing production wells in the Gas Fields (upon the expiration of domestic gas contracts), the further development of the Gas Fields, gas produced by Santos from Santos' other tenements (including in the Cooper Basin) and other third party suppliers. Gas that is purchased from some of Santos' other tenements, third parties or which is stored in GLNG's underground storage reservoirs will likely need to be processed by GLNG at the Treatment Facility or otherwise managed by GLNG (for example, through blending) to ensure that it meets the gas specification required by the LNG Facility.

In addition to the drilling of exploration and production wells and the construction of field gathering lines, the Gas Fields development also includes centralised compression and water treatment facilities, accommodation

facilities, power generation, water management facilities and other incidental infrastructure and activities.

1.1.2 LNG facility

The LNG facility is essentially a large cooling system that lowers the temperature of the natural gas by using refrigerants, thereby transforming it from a gaseous state to a liquid state. Natural gas is piped into the plant and is initially treated to remove impurities, carbon dioxide and water from the natural gas. The gas then undergoes a liquefaction process by using refrigerants to lower the temperature of the natural gas until it liquefies. The LNG is then stored in full containment LNG tanks at atmospheric pressure prior to shipping.

To achieve this process, the LNG Facility consists of:

- a liquefaction facility which includes the on-shore gas liquefaction and storage facilities;
- marine facilities which will include a product facility for loading LNG into tankers for export, and a facility and haul road for the delivery of equipment, plant, materials and personnel to and from the LNG Facility site;
- a swing basin and access channel from the existing Targinie Channel in Port Curtis; and
- a temporary workers accommodation facility on Curtis Island for construction workers.

GLNG made the final investment decision to construct a two-train LNG Facility at Hamilton Point West on Curtis Island, Gladstone on 13 January 2011. These two trains will have a combined nameplate capacity of 7.8 million tonnes per year (Mtpa). The LNG facility may produce more or less LNG than the nameplate capacity, depending on feed gas composition, pipeline/plant interface pressure and temperature, site ambient air temperature, refrigeration compressor and refrigeration gas turbine de-rating applied, refrigeration compressor gas turbine inlet air temperature and facility operating mode (ie whether concurrent ship loading is occurring) with an ultimate capacity of 8.82 Mtpa (under favourable conditions).

Construction of the LNG Facility commenced in May 2011. The first stage of the development, Train 1, will have a nameplate capacity of approximately 3.9 Mtpa with the first cargo expected in the first quarter of 2015. The second stage of the development, Train 2, also has a nameplate capacity of 3.9 Mtpa with the first cargo from Train 2 expected in the fourth quarter 2015.

If the GLNG Project proceeds to full development (that is, three trains) the LNG facility will have a nominal capacity of approximately 10 Mtpa. GLNG is

yet to make a final investment decision on expanding the project to include a third train.

Gas specification

CSG from different gas fields and conventional gas can generally be used interchangeably in most production processes provided the gas complies with AS 4564 Australian Standard Specification for General Purpose Natural Gas. To be economical however, LNG facilities are usually designed for gas of a much narrower specification, based on the expected composition of the gas intended to be supplied over the design life of the facility. The Pipeline is also not specifically designed to accommodate the full range of gas specification allowable under AS 4564.

The LNG Facility, including contaminant limit levels and removal units (eg acid removal units and mercury removal units) has been designed for feed gas of the average specification expected to be produced at the Gas Fields, [Confidential]

As discussed above, GLNG will be acquiring some gas for the GLNG project from third parties. It will also have to store gas, including CSG, from time to time (particularly during the ramp up period) at its Roma Underground Gas Storage facility. GLNG will construct the Treatment Facility if necessary to ensure that all gas purchased from third parties by GLNG or stored in the Roma Underground Gas Storage facility meets the specification and contaminant design limits before it is injected into and transported through the Pipeline to the LNG Facility.

CSG originating from fields other than the Gas Fields (ie third party gas) is unlikely to meet the narrow LNG Facility gas specification design limits without treatment. Any conventional gas is highly unlikely to meet design limits without treatment. Unless treated prior to entering the Pipeline to meet the design limits, any third party gas transported in the Pipeline exceeding the design limits will comeingle with and contaminate CSG from Gas Fields (and other third party gas treated by GLNG). Consequently, other third parties seeking access to the Pipeline would need process their gas to meet the specification required by LNG Facility before delivering it into the Pipeline.

1.1.3 The Pipeline

Gas meeting the specifications of the LNG Facility will be transported from the Gas Fields to the LNG Facility through the Pipeline. The Pipeline is a 420 kilometre gas transmission pipeline designed to deliver gas from the Gas Fields to the LNG Facility.

The Pipeline is a Class 600 high pressure transmission pipeline with an external diameter of 1,067 millimetres, designed to operate at pressures up to 10.2MPag. The lowest pressure at which the Pipeline will operate is determined by the LNG Facility with production at the LNG Facility reducing if gas enters the Pipeline at less than 6.5 MPag and the LNG Facility effectively shutting down if gas enters the Pipeline at less than 4.5 MPag.

The Pipeline will be designed, constructed and operated in accordance with the Australian Pipeline Standard and constructed of continuously welded high quality/high tensile strength steel. The Pipeline will be constructed using traditional open cut trenching, apart from water crossings where horizontal directional drilling or another construction methodology may be utilised.

The capacity of the Pipeline will vary throughout the year as conditions, such as temperature and gas composition, change. In winter, cooler temperatures mean that the Pipeline can be expected to transport up to 1,429 TJ/d based on the specification of the CSG from the Gas Fields, while in summer this may reduce to 1,378 TJ/d. It is estimated that the capacity of the Pipeline will average 1,400 TJ/d across the year.

Each train of the LNG Facility requires a daily average flow rate of 600 TJ/d (or 1,200 TJ/d for two trains) averaged across the course of a year in order to meet the foundation offtake agreement commitments. The actual capacity of the LNG Facility will vary from its name plate capacity from day to day for the technical reasons previously described, such that on some days the LNG Facility will be operating at less than full capacity and less than 600 TJ/d will be able to be processed. The LNG Facility will need to operate at or close to its maximum capacity (ie above the name plate capacity) at times to make up this reduction, which requires that the Pipeline also be available to transport at the Pipeline's maximum capacity and to deliver around 695 TJ/d to each train (or 1,390 TJ/d for two trains) at any time.

The notional "spare capacity" in the Pipeline is consequently required to ensure GLNG can operate the LNG Facility at its maximum capacity where technically possible.

The Pipeline is not only designed to have the capacity required to supply sufficient gas to the LNG Facility, but also to operate as an important buffer between the operations of the LNG Facility and the Gas Fields. The LNG Facility will, on occasion, have planned and unplanned shut-downs as a result of which less gas will be able to be received. It is difficult to shut down the Gas Fields at short notice without loss of production due to the nature of CSG production and the number of wells needed to produce the gas for the LNG Facility. GLNG has limited storage options for CSG produced at the Gas Fields, but not required by the LNG Facility, and intends to use the Pipeline

(together with the limited storage facilities being constructed by GLNG at Roma) to temporarily store the CSG in these situations.

There will be a ramp up period for each train of the LNG Facility associated with the ramp up of CSG production in the Gas Fields following commissioning of the LNG Facility. If the Participants were entirely dependent on daily production from the Gas Fields for supply to the LNG Facility, then theoretically there would be "spare" (albeit progressively declining) capacity available in the Pipeline for the limited ramp up period. However, to provide more consistent supply and to maximise LNG cargos during the Gas Fields' ramp up period, the Participants have already commenced storage of gas currently being produced in the Gas Fields in the Roma Underground Storage Facility. This will be drawn upon during the ramp up. The Participants are also seeking to source third party gas for supply to the LNG Facility during the ramp up period (for example, the binding Heads of Agreement signed by the Participants with Origin Energy in May 2012 for the supply of gas from 2015). The extent of any available capacity in the Pipeline during the Gas Fields' ramp up period will be consequently dependent on the Participants' ability to store and/or source supplementary gas supply to the LNG Facility. Once the Gas Fields and the LNG Facility are fully operational, any capacity in the Pipeline that may be available will be very uncertain and subject to daily fluctuations in the quantities of CSG produced at the Gas Fields and the operation of the Pipeline and LNG Facility as discussed above.

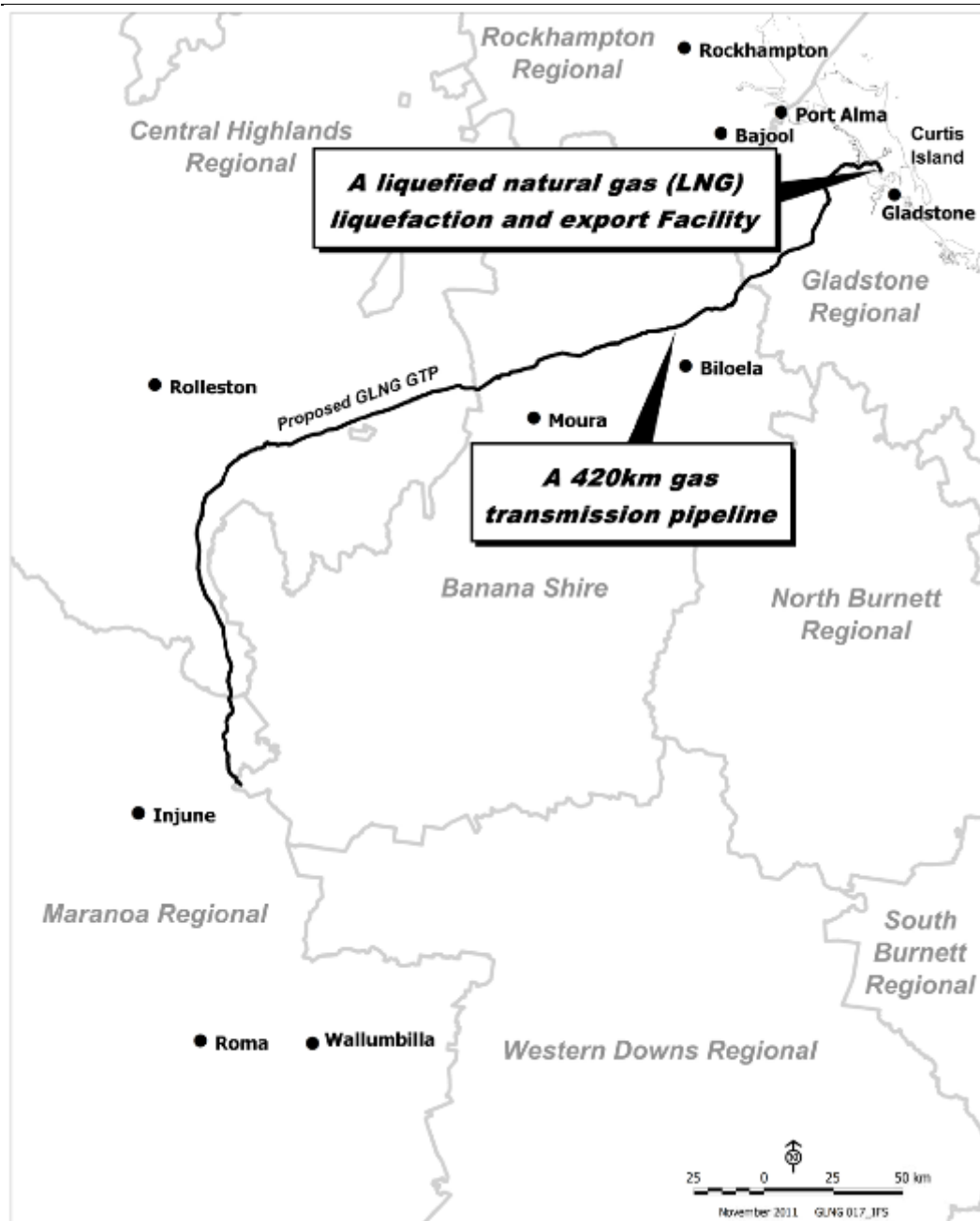
As previously stated, no decision has yet been made on expanding the LNG Facility to include a third train. If the GLNG Project proceeds to three trains, the Participants would need to either expand the capacity of the Pipeline through compression or looping of the as-built Pipeline, or construct a second pipeline. While the Participants have not formed a view as to which option they might ultimately pursue, we understand that very preliminary estimates suggest the addition of compression would be the most cost effective option having regard to the Participants' expected capacity requirements.

Pipeline route

The route of the Pipeline is illustrated in Figure 1.



Figure 1 **Route for the GLNG Gas Transmission Pipeline**



Source: GLNG "Application for Governor-in-Council approval of the GLNG Infrastructure Facility as an Infrastructure Facility of Significance", Annexure A, November 2011

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 GLNG 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 incorporated its latest in-house assumptions with regard to gas supply and demand in Eastern Australia, with assumptions relating to the GLNG project reflecting the proponents current design parameters.

The study scope includes the following sections:

- A. Downstream Markets projected gas demand and prices over the period to 2030, including impact of government policies on domestic gas supply and demand
- B. LNG Export Market over the period to 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 including Paul Balfe, an Executive Director of ACIL Tasman who has overall responsibility for the firm's gas business and Martin Pavelka (Analyst).

Summary curriculum vitae information for the consultants is set out in Appendix A.

2 Downstream market projections to 2030

Chapter Summary

The main downstream gas market potentially serviced by the GLNG Gas Transmission 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 GLNG Gas Transmission 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 GLNG Gas Transmission Pipeline.

Several LNG export proposals have been investigated in the Gladstone region, including two other projects (Queensland Curtis LNG Project and Australia Pacific LNG Project) that have reached final investment decision. These projects will see further dedicated pipeline connections constructed linking the CSG fields of the Surat and Bowen Basins to Gladstone.

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

- Gladstone – 37.9 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 50PJ/a by 2015. 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 the type typical of the Gladstone area, 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 no specific long-term development proposals have been identified.

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\$4.00 to A\$5.50/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 Cleaner Energy Future (CEF) carbon pricing package is expected to be directionally 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. CEF will also result in higher sustainable gas prices because of improved competitiveness with coal on a carbon-inclusive basis. CEF is estimated to increase the wholesale price of gas by around A\$1.00/GJ for each A\$30/t CO₂e carbon price. The Small-scale Renewable Energy Scheme (SRES) Large-scale Renewable Energy Target (LRET), 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 LRET scheme is unlikely to have a great effect on gas demand in the Gladstone region because there is a lack of good quality wind generation sites in Central Queensland.

The Queensland Government during 2009 adopted policies aimed at ensuring availability of gas for domestic purposes under reasonable terms.

Gas market modelling was undertaken in April 2012, prior to APLNG taking a final investment decision on its second train. Results of modelling two LNG development scenarios are presented: a "Project Case" involving development of the first two LNG trains proposed by GLNG together with the currently committed two trains at QCLNG and one further train at APLNG; and an "Industry Case" that includes two GLNG trains plus three trains at QCLNG; two trains at APLNG and two trains at Arrow-Shell for a total of nine LNG trains with annual production capacity of around 36 Mtpa.

Both scenarios show that anticipated gas demand in the downstream markets is substantially satisfied throughout the modelling period (to 2030) without utilisation of the GLNG Gas Transmission Pipeline for carriage of gas to domestic markets.

The model was configured so that all gas delivered into the Gladstone domestic market is transported via the existing Queensland Gas Pipeline (QGP), rather than the GLNG Gas Transmission Pipeline. No gas is delivered to the Gladstone domestic market via the GLNG Gas Transmission Pipeline.

Modelling of gas prices under the two scenarios shows relatively flat 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\$4.00/GJ delivered at Gladstone prior to commissioning of the LNG facilities to around A\$6.90 (real, 2011) by 2020 in the "Project Case", and around A\$7.20/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 GLNG Gas Transmission 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 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 to 2030.

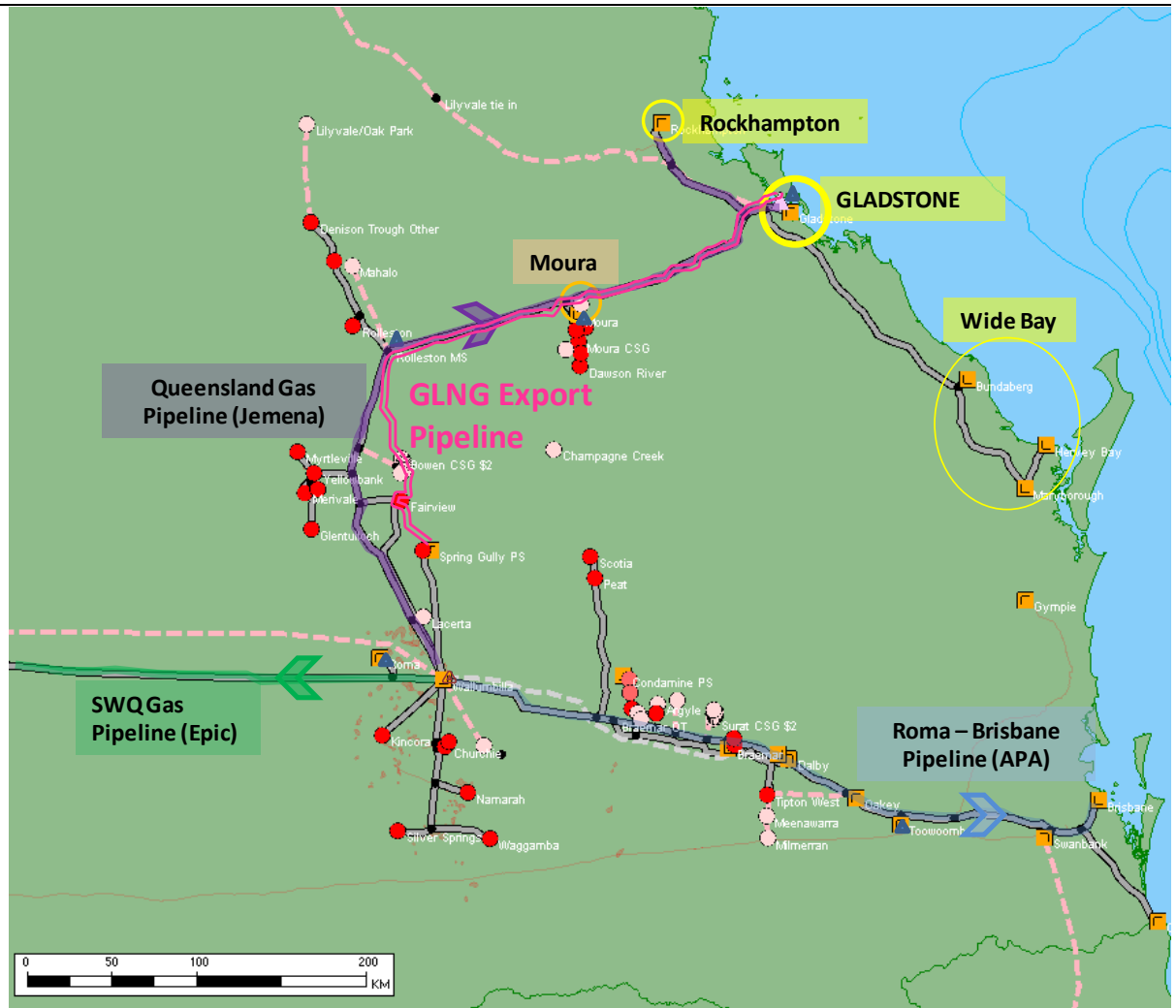
2.1 Relevant downstream markets

Figure 2 shows the location of the GLNG Gas Transmission 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 GLNG Gas Transmission Pipeline. At present there is a single transmission pipeline servicing the Gladstone market (the Queensland Gas Pipeline or QGP, operated by Jemena). Gas delivered to Gladstone via the GLNG Gas Transmission Pipeline could potentially be transferred to the QGP system for carriage on the Larcom Creek – Rockhampton Lateral which is the only gas transmission pipeline currently available for transport of gas to customers at **Rockhampton**. Alternatively, gas delivered to Gladstone via the GLNG Gas Transmission Pipeline could potentially be transferred to the Gladstone – Wide Bay Pipeline (operated by Origin Energy) which is the only gas transmission pipeline currently available for transport of gas to the **Wide Bay** area (Bundaberg, Maryborough and Hervey Bay).

The only other existing gas market that could potentially be serviced from the GLNG Gas Transmission Pipeline is at **Moura**. However, the only significant gas customer at Moura (Queensland Nitrates Pty Ltd – a joint venture involving Dyno Nobel [a subsidiary of Incitec Pivot] and CSBP Wesfarmers) has a relatively small gas requirement of around 3 PJ/a. It 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 GLNG Gas Transmission Pipeline.



Figure 2 Downstream markets for the GLNG Gas Transmission Pipeline



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

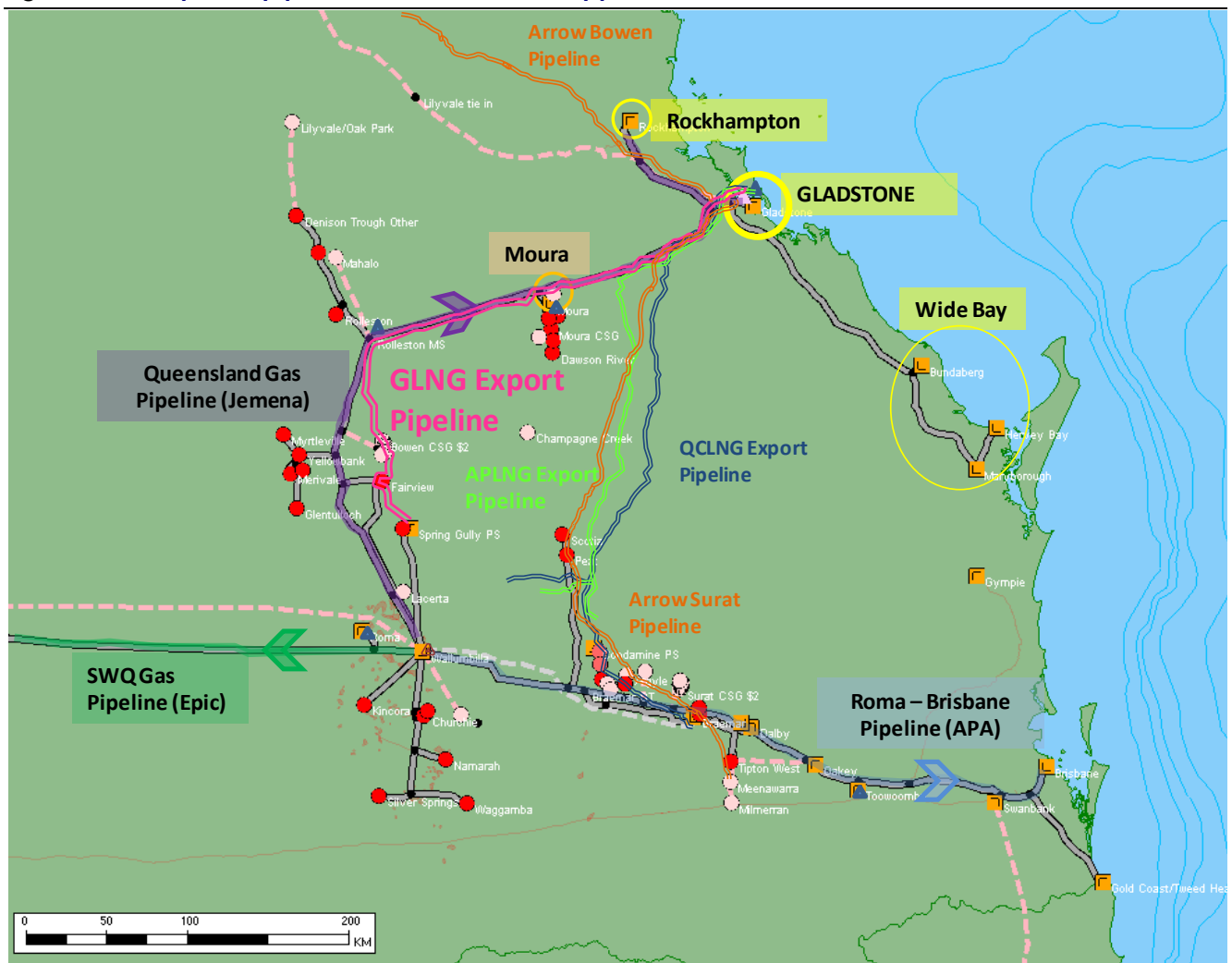
2.1.1 Other CSG LNG Export proposals

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 proposed routes of export gas pipelines from the CSG production fields to proposed LNG plants near Gladstone for three other advanced CSG LNG projects: Queensland Curtis LNG (BG Group/China National Offshore Oil Corporation); Australia Pacific LNG (Origin Energy/ConocoPhillips/Sinopec) and Arrow LNG (Shell/PetroChina).

The QCLNG and APLNG projects are now committed, with their proponents progressing construction of their respective gas transmission pipelines to Gladstone independently. These will provide two further pipeline connections from the CSG fields of the Surat and Bowen Basins to Gladstone.

The Arrow LNG Project is not yet committed but is being actively progressed. The Arrow project involves two separate pipelines to carry CSG feed to the LNG plant: the Arrow Surat Pipeline which will bring gas from the Surat Basin and the Arrow Bowen Pipeline which will carry gas from the northern Bowen Basin region.

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

In addition to these large projects, LNG Limited is proposing to construct up to 3 Mtpa of LNG capacity at Fisherman's Landing, north of Gladstone.

2.1.2 Current gas consumption in the relevant downstream markets

In 2010-11 levels of gas consumption in the relevant downstream markets were estimated to be as follows:

- Gladstone – 37.9 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 the Wide Bay region). There is no existing or anticipated gas-fired power generation other than through co-generation in the relevant markets¹.

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

	2010–11*	2015	2020	2025	2030
Gladstone	37.9	49.6	50.1	49.1	50.3
Rockhampton	1.6	1.6	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
TOTAL	39.8	51.6	52.2	51.1	52.5
Industrial	32.5	37.9	38.5	38.6	38.6
Cogeneration (Gladstone)	6.7	13.0	12.9	11.7	12.9
Retail small customers	0.6	0.7	0.8	0.9	1.0

* Demand in PJ per year; totals may not add due to rounding

Data source: Values for 2011 based on National Gas Market Bulletin Board throughput data for QGP during year ended 30 June 2011; forecast data from ACIL Tasman *GMG Australia* model

¹ On 25 October 2011 TRUenergy announced that it is seeking relevant approvals for two gas-fired power stations, one at Swanbank and one at Gladstone. However, at this stage no decision has been made as to the final timing and configuration of these stations (CCGT or OCGT) and it is therefore not possible to estimate the gas demand associated with the proposed Gladstone station.

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**

	2011	2015	2020	2025	2030
Boyne Is. Smelter	1.4	1.4	1.4	1.4	1.4
YAR Stage 2 Calcining	7.2	7.2	7.2	7.2	7.2
Comalco Refinery - Calcining	4.0	4.0	4.0	4.0	4.0
Gladstone Base Market	0.2	0.2	0.2	0.3	0.3
Orica - NaCN chloralkali	3.7	3.7	3.7	3.7	3.7
Orica NH ₄ NO ₃ expansion	0.0	2.8	2.8	2.8	2.8
QAL - Alumina Plant Expansion	0.0	5.0	5.0	5.0	5.0
QAL Alumina Plant	11.8	12.3	12.9	13.0	13.0
Yarwun Cogen	6.7	13.0	12.9	11.7	12.9
TOTAL	35.0	49.6	50.1	49.1	50.3

Demand in PJ per year; totals may not add due to rounding

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 identified as coming 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 one of the largest in the world, with a maximum annual rated capacity of 3.95 million tonnes. Bauxite from the Weipa mine on Cape York Peninsula is processed in the refinery to produce alumina, which is then shipped to 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
- 16 PJ/a of natural gas
- 16 MW of grid electricity and 16 MW of internally-generated electricity.

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 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. Deliveries under the contract are now understood to have increased to around 16 PJ/a following expansion of Origin's production capacity at Spring Gully in 2006 and 2007 and development of the Talinga CSG production facility.

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-raising²
- 4 PJ/a of natural gas for calcining
- 63 MW of grid electricity.

Gas supply for Stage 1 calcining requirements was provided 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.

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. Completion of the Stage 2 expansion is now expected late 2012–early 2013.

As part of the expansion, a 160 MW gas cogeneration plant has been constructed (completion 2H2010) 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 expansion (compression and looping) of Jemena's Queensland Gas Pipeline (QGP) being also required, increasing throughput capacity to 52 PJ/a.

There is potential for a further 2 Mtpa expansion (Yarwun Stage 3) which Rio Tinto has indicated it will consider once the Stage 2 expansion is completed.³ We have not factored Yarwun Stage 3 into our demand projections.

Orica

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

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.

³ Rio Tinto, "Bauxite and Alumina Investor Site Visit", 23 June 2010.
http://www.riotinto.com/documents/Media-Speeches/100623_Yarwun_Analyst_Visit_June2010.pdf accessed 11 April 2012.

- Sodium cyanide plant (95,000 tpa following progressive uprating of original 20,000 tpa plant)
- Chloralkali production (9,500 tpa as caustic soda)
- Ammonium nitrate (NH_4NO_3 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 (95,000 tpa)
 - Natural gas 36 GJ per tonne product, therefore about 3.4 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 supplied under a contract from Fairview. The contract (originally written with Tipperary Oil and Gas Australia) commenced on June 26, 2006, and provided for Orica to purchase a minimum of 3.2 TJ/day and a maximum of 5 TJ/day. The term of the contract was for 10 years. Santos now supplies this contract after its acquisition of Tipperary's Fairview assets in 2005.

In light of ongoing rapid growth in the Bowen Basin coal mining industry we have assumed a further expansion of ammonium nitrate production capacity at Orica's Yarwun facility, requiring a further 2.8 PJ/a by 2015.

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 tpa⁴. It is the largest smelter in Australia and presently the fourth largest in the world. The smelter operates

⁴ As at 31 December 2008: (Rio Tinto, 2009).

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.

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.

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 re-firing the calcined magnesia to a temperature of $2,000^\circ\text{C}$ 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 $3,000^\circ\text{C}$. 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.

2.3.3 Reticulated demand

Envestra's Northern distribution network supplies small customers in both Gladstone and Rockhampton. Reticulated gas demand is relatively small at around 0.3 PJ/a, as shown in Table 3.

Table 3 **Gladstone & Rockhampton: actual and forecast reticulated demand (TJ/a)**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Domestic	17	18	23	23	23	23	23	23	22	22	22
Commercial	118	133	92	93	93	96	101	104	105	106	108
Large users	144	152	159	133	134	136	140	142	141	141	142
Total	278	304	274	249	251	255	264	269	269	269	272

Data source: Historical consumption and demand forecasts for Envestra, from 2011 Access Arrangement Information

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 309 km. The pipeline has a low capacity, being only 100 mm 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\$4.00 to A\$5.50/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 used per billing period increases. Origin Energy is the main supplier of retail gas in Gladstone, Rockhampton and Wide Bay. According to Origin Energy's published schedule of tariffs applicable from 20 July 2011 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	56.13	67.05
Residential 20 GJ/a	37.57	35.89
Commercial/Industrial 100 GJ/a	31.39	31.14
Commercial/Industrial 250 GJ/a	29.13	29.80

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 carbon pricing (Clean Energy Future package) and the Large-scale Renewal Energy Target (LRET).

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 Clean Energy Future

On 10 July 2011 the Australian Government released a policy document, *Securing a Clean Energy Future*, which foreshadowed the introduction of a carbon tax commencing on 1 July 2012 at a nominal rate of \$23.00 per tonne of CO₂-e emissions to apply to the top 500 emitters in Australia including the coal mining industry. The tax rate is to increase by 2.5 per cent per year in real terms and remain in place until 30 June 2015. From 1 July 2015, the carbon tax is to be replaced by an emissions permit trading scheme.

The policy document was accompanied by a Treasury report, *Strong Growth, Low Pollution*. This report provided some information on an estimated carbon price trajectory out to 2050 and estimated effects of the emissions abatement package. The Treasury report included forecasts of inflation and an index of forecast future export coal prices. Subsequently, more detailed information was released regarding the estimated carbon price trajectory.

Under the medium global action scenario, Treasury has estimated that the international market price in 2015/16 will average around \$A29/t CO₂-e in nominal terms and increase at around 5.0 percent per annum in real terms to

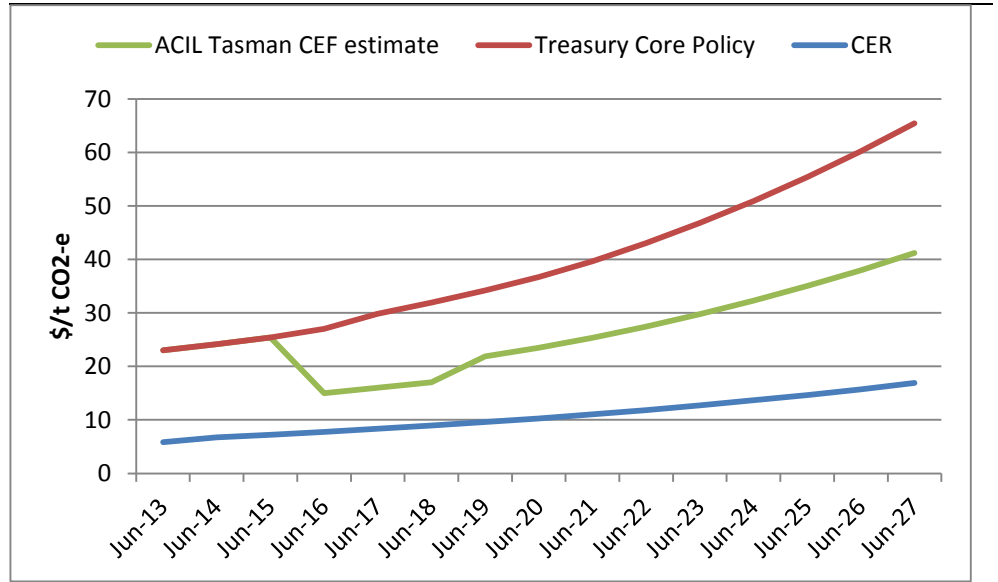
2050. While this “Core Policy” scenario appears to be Treasury’s central case in the modelling undertaken to support the development of the CEF, key assumptions behind the modelling including coordinated global action by 2015 with the aim of limiting greenhouse gas emissions to 550 ppm by 2100 appear now to be very unlikely to materialise. Hence ACIL Tasman considers that the Core Policy scenario is on the high side of likely carbon price paths over the period in which the modelling is undertaken.

The carbon price used by ACIL Tasman in modelling the gas scenarios has been estimated using the Department of Treasury Core Policy scenario published price path and the InterContinental Exchange (ICE) forward curve for Certified Emissions Reductions (CER) traded within Europe as part of the European carbon cap and trade arrangements. CER are permitted to be remitted to meet liabilities under the CEF. The structure of the CEF arrangements has been retained in the ACIL Tasman estimated carbon price path. In particular the first three years of the price path are fixed followed by the next three years being subject to a cap and floor. The first five years after the fixed price period are also subject to an international permit import restriction of 50% of all emission permits remitted (although ACIL Tasman analysis indicates that this constraint will not have any real impact on domestic carbon prices).

Figure 4 compares the carbon price trajectory used by ACIL Tasman and the carbon price trajectory under the CEF Treasury Core Policy scenario. The ICE CER forward curve is also provided for comparison. In both the Treasury Core Policy and ACIL CEF estimate carbon price path trajectories, the carbon price is fixed for the first three years of the scheme commencing July 2012 (price in 2012/13 to 2014/15 is \$23.00, \$24.15 and \$25.40 respectively in nominal terms).

In the ACIL CEF estimate, the carbon price path moves to the legislated floor between 2015/16 to 2017/18 of \$15.00, 16.00 and 17.05 respectively in nominal terms. The carbon price path in subsequent years reflects the mid-point (average) of the Core Policy price path and the ICE forward curve.

Figure 4 **Carbon price trajectory – Base case, Treasury Core policy and ICE CER forward curve**

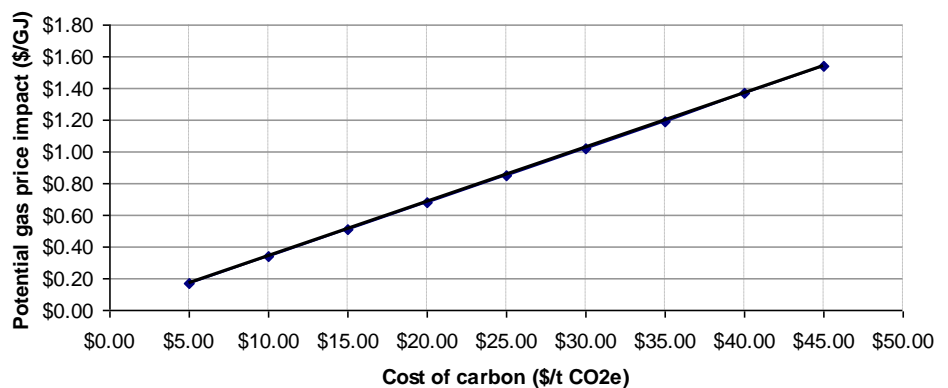


Data source: Commonwealth Treasury (Core Policy), ICE Forward Curve (27 January 2012) and ACIL Tasman analysis

Impact of carbon pricing on Eastern Australian gas prices

Figure 5 shows ACIL Tasman's estimates of the potential impacts of carbon pricing on wholesale gas prices.

Figure 5 **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 the CEF carbon pricing scheme could result in a rise in real wholesale gas prices of up to A\$0.75/GJ initially (from mid 2012), rising to around A\$2.00/GJ by 2030.

2.5.2 SRES and LRET

The Small-scale Renewable Energy Scheme (SRES) and Large-scale Renewable Energy Target (LRET) have the potential to affect demand for gas in electricity generation. Both schemes will tend to suppress consumption of gas for power generation. Installation of solar photovoltaic panels under the SRES is resulting in some reduction in wholesale electricity demand growth throughout the National Electricity Market (NEM).

The LRET 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.

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 plants locate—which will be mainly in Victoria and South Australia.

The lack of good quality sites for wind generation in Central Queensland means that the LRET scheme is unlikely to have a significant impact on gas demand in the downstream markets relevant to the GLNG Gas Transmission 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"⁵

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 GLNG 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.

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.

⁵ Queensland Government, 2009: "Consultation Paper. Domestic Gas Market Security of Supply", p.2.

In the 2011 Gas Market Review the Queensland Gas Commissioner stated that:

“Customer concerns regarding access to gas reserves for contracting in the period 2011 to 2015 for gas supply commencing in the period 2015 to 2020 are supported by the modelling and analysis undertaken for the GMR. This indicates a tight reserves position as LNG projects prove up reserves to underpin LNG projects.”

The corresponding recommendation by the Queensland Gas Commissioner was that:

“... the government seek detailed advice, confirmation and commitment from gas producers regarding drilling and appraisal programs to provide reserves for new domestic contracting in the period 2011 to 2015 for gas supply in the period 2015 to 2020.”

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.

The gas market modelling was undertaken in April 2012, prior to APLNG taking a final investment decision on its second train.

Two modelling scenarios were developed.

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

2.6.1 Modelling scenarios

The two modelling scenarios were:

- A **“Project Case”** involving development of the first two LNG trains proposed by GLNG together with the currently committed two trains at QCLNG and one train at APLNG, for a total LNG production capacity of around 20.8 Mtpa.
- An **“Industry Case”** that adopted the same assumptions as the “Project Case” except for inclusion of four additional LNG trains—one additional train each for QCLNG and APLNG, and two trains for Arrow LNG. We assumed that the LNG facilities are independently serviced by dedicated transmission pipelines from the CSG production fields to the liquefaction facilities. The Central Queensland Gas Pipeline (Moranbah to Gladstone) associated with the Arrow LNG Project was assumed to include a tie-in to the domestic market.

2.6.2 Modelling assumptions

Both scenarios took as their starting point ACIL Tasman’s then current base case outlook for the eastern Australian gas market in terms of existing and new

entrant gas supply (conventional and CSG), gas reserves, gas demand at individual load level, and existing and future pipeline networks. Both scenarios incorporated 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 included:

- the future contribution of Coal Seam Gas (CSG) in Queensland and New South Wales to the overall supply of gas for domestic markets
- commencement of the CEF carbon pricing package in mid 2012 and the consequences for demand for gas in power generation and for gas price tolerances. The carbon price assumptions adopted were consistent with the ACIL Tasman CEF assumptions discussed in section 2.5.1
- 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 included:

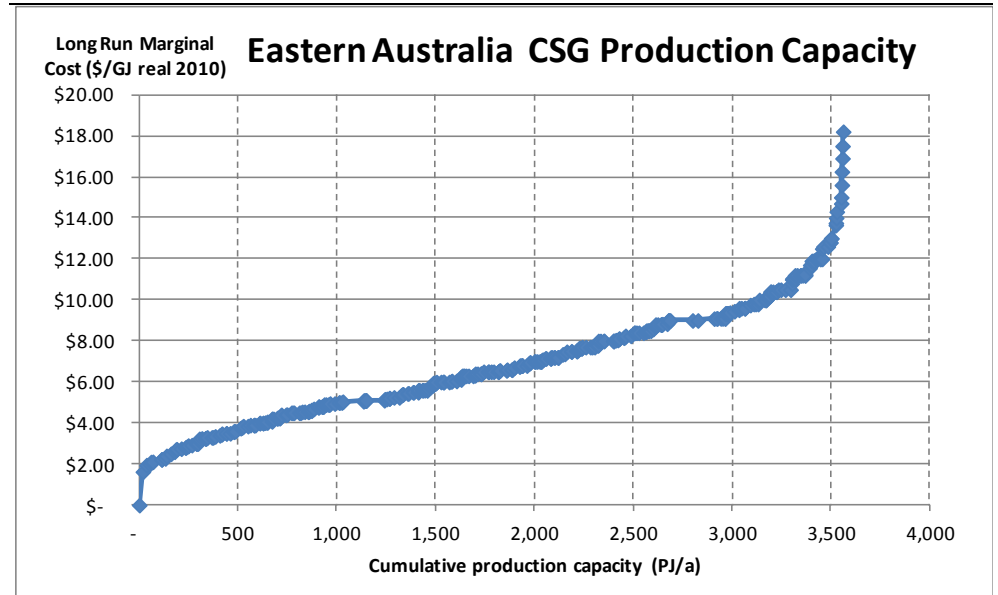
- Current mid-range estimates for future supply
 - from existing fields, based on current production capacity and known reserves
 - from new discoveries based on reasonable assessments of discovery rates and output profiles when brought into production
 - minimum producer price assumptions based on an expectation of increasing costs over time to discover new gas reserves and to bring new production on line, taking into account recent price trends and expectations
- With regard to coal seam gas (CSG) in Queensland, continued expansion of production and reserves with costs increasing over time as more expensive, less productive deposits are accessed.
- With regard to CSG in New South Wales current exploration succeeds in establishing substantial production capacity, again with costs increasing over time as more expensive, less productive deposits are accessed.
- Bass Strait conventional gas
 - production and resource backing for existing fields reflects installed production capacity and known gas reserves (proven & probable, “2P”)
 - significant new reserves are discovered and production capacity established as a result of on-going exploration in Otway Basin, Bass Basin and Gippsland Basins.
- On the demand side the following was assumed:

- Retail (commercial and residential) demand growth driven by demographic and economic (GSP) trends and consistent with recent historical trends in each jurisdiction
 - Growth in the small (retail) industrial sector driven by economic (GSP) trends and consistent with recent historical trends in each jurisdiction
 - Demand from large industrial users (generally non-retail, contracting directly with gas suppliers) based on assessments of individual existing loads, proposed expansion of existing facilities (brown field developments) and proposed new projects (green field developments)
 - Gas demand for power generation based on calculated fuel demand associated with dispatch of individual existing and new entrant generators, as derived from ACIL Tasman electricity market modelling.
- ... Gas for power generation requirements takes into account increased demand for gas-fired power generation as a result of introduction of the Clean Energy Future carbon pricing package, and government emission reduction and renewable power generation targets.

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

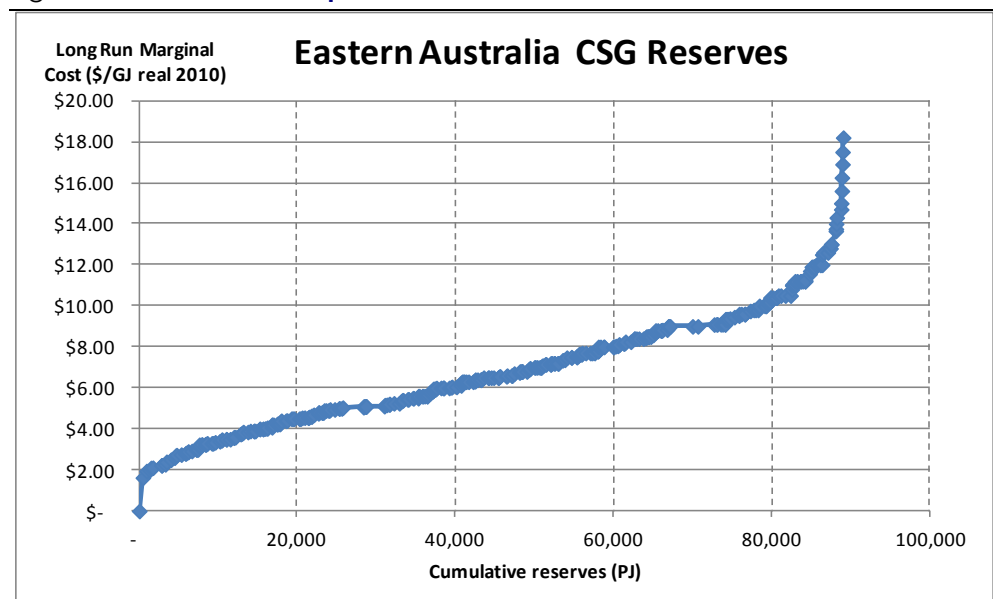
For CSG in both Queensland and New South Wales, we assumed continued expansion of production and reserves base with average production costs increasing over time as more expensive, less productive deposits are accessed. We assumed total production capability from CSG (both states combined) of around 3,500 PJ/a across a range of price points as shown in Figure 6. Assuming production over a period of 25 years, this implies a total recoverable resource in place of about 90,000 PJ (Figure 7).

Figure 6 **Eastern Australia CSG production cost curve: production capacity basis**



Data source: ACIL Tasman analysis

Figure 7 **Current CSG production cost curve: Reserves Basis**



Data source: ACIL Tasman analysis

2.7 Modelling results

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

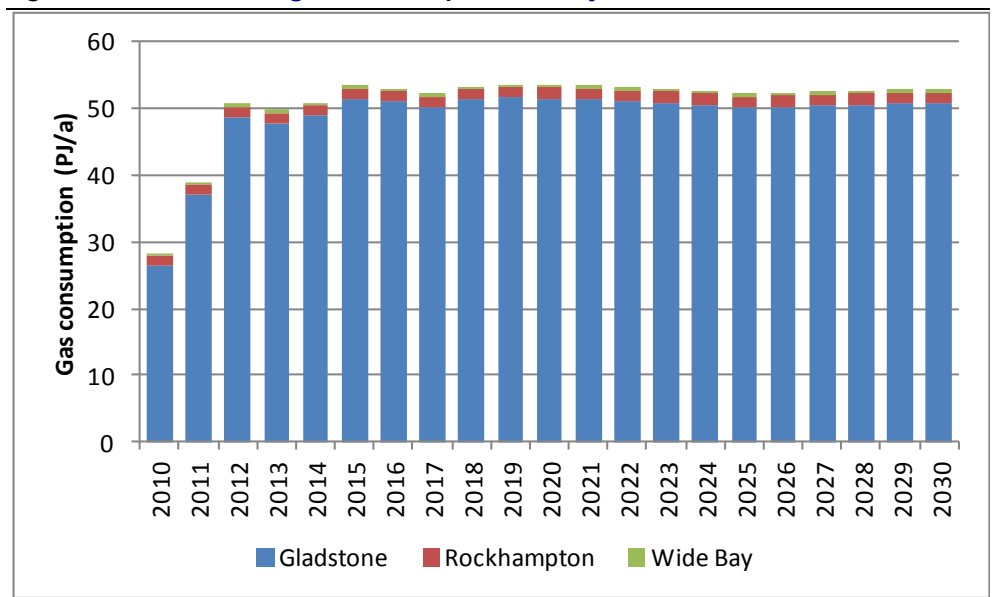
2.7.1 Gas consumption

Project Case

Figure 8 and Table 5 show the modelled gas consumption in the relevant downstream markets under the “Project Case” assumptions. Note these consumption results are model outputs, whereas the demand assumptions set out in Table 1, Table 2 and Table 3 are model inputs. There may be differences between the model output results (consumption) and the model input assumptions (demand) for reasons including price elasticity effects, field production limits and pipeline capacity constraints.

The results highlight the fact 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 throughout the projection period.

Figure 8 **Modelled gas consumption—“Project Case”**



Source: ACIL Tasman GMG Australia modelling

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

	2011	2015	2020	2025	2030
Gladstone	37.1	51.4	51.5	50.2	50.7
Rockhampton	1.6	1.6	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
TOTAL	39.0	53.4	53.5	52.3	52.9

Data source: ACIL Tasman GMG Australia modelling; totals may not add due to rounding

The minor decline in total consumption post 2020 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 28 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”**

	2011	2015	2020	2025	2030
Boyne Is. Smelter	1.4	1.4	1.4	1.4	1.4
Orica - NaCN cholalkali	3.8	3.8	3.8	3.8	3.7
Orica NH ₄ NO ₃ expansion	0.0	2.8	2.8	2.8	2.8
Comalco Refinery - Calcining	4.1	4.1	4.1	4.1	4.0
QAL Alumina Plant	13.1	13.3	13.7	13.7	13.3
QAL - Alumina Plant Expansion	0.0	5.1	5.0	5.0	5.0
Gladstone Base Market	0.2	0.2	0.2	0.3	0.3
YAR Stage 2 Calcining	3.7	7.4	7.3	7.3	7.2
Yarwun Cogen	0.0	13.3	13.1	11.9	13.0
TOTAL	26.3	51.4	51.5	50.2	50.7

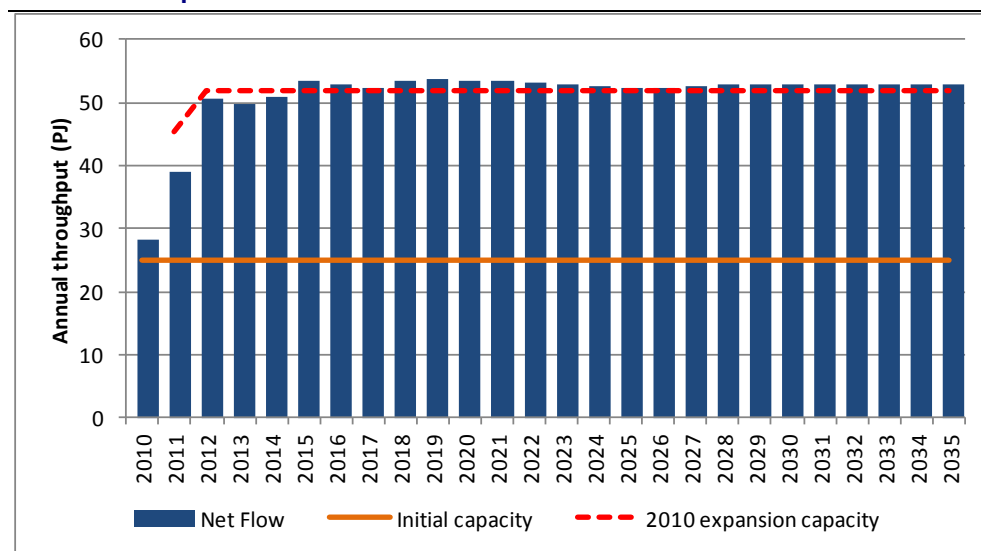
Note: ACIL Tasman GMG Australia modelling; totals may not add due to rounding

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). For the Project Case it was assumed that the proposed Central Queensland Gas Pipeline (Moranbah to Gladstone) is not constructed because the Arrow LNG project (which would provide the underpinning load for construction of the CQGP) is not included. The GLNG Gas Transmission Pipeline and the large-diameter pipelines servicing the QCLNG and APLNG projects do not carry gas to the domestic market.

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 9, which also shows the initial installed capacity and increased capacity after completion of the recent expansion program.

Figure 9 **Modelled annual gas throughput on the Queensland Gas Pipeline**



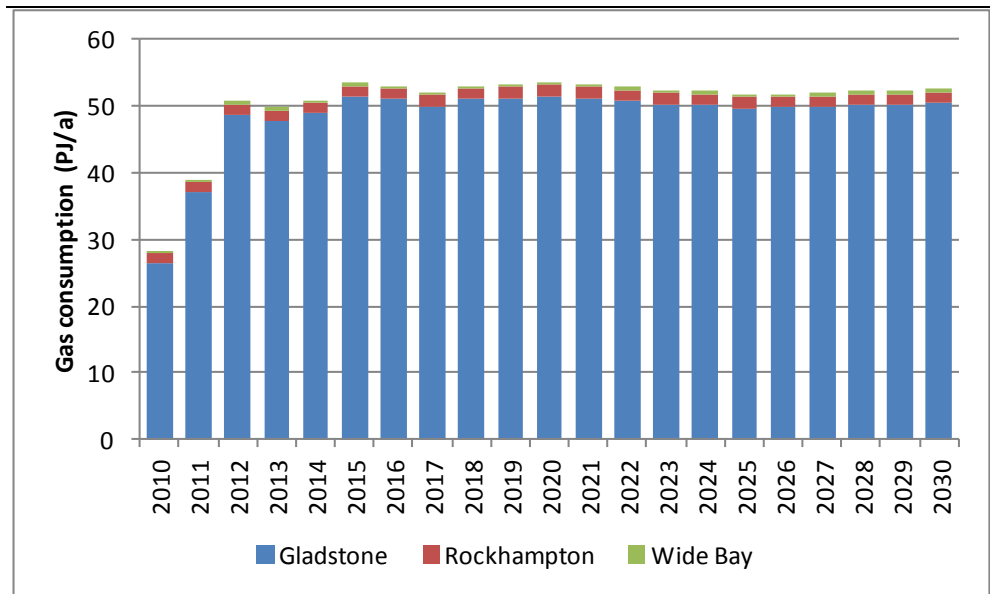
Source: ACIL Tasman GMG Australia modelling

For modelling purposes the QGP was assumed not to be capacity constrained which means that the model allowed shipment of gas through QGP in excess of the current defined capacity limits. In other words, it was assumed that the current 52 PJ/a capacity of QGP does not limit the quantity of gas that can be shipped to Gladstone via that pipeline. However, as indicated in Figure 9, the modelling results show that almost all of the projected domestic gas consumption in Gladstone, Rockhampton and Wide Bay can be accommodated within the existing capacity if a flat load profile is assumed. In practice some further expansion of QGP capacity may be required to meet peak day requirements. For modelling purposes, it was assumed that any such additional capacity would be available at the current prevailing tariff rates.

“Industry Case”

The corresponding results under the “Industry Case” with nine LNG trains and increased CSG production 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”**

	2011	2015	2020	2025	2030
Gladstone	37.1	51.4	51.5	49.7	50.4
Rockhampton	1.6	1.6	1.6	1.6	1.6
Wide Bay	0.3	0.4	0.4	0.5	0.5
TOTAL	39.0	53.4	53.5	51.8	52.6

Data source: ACIL Tasman GMG Australia modelling; totals may not add due to rounding

Table 8 **Modelled gas consumption in Gladstone—“Industry Case”**

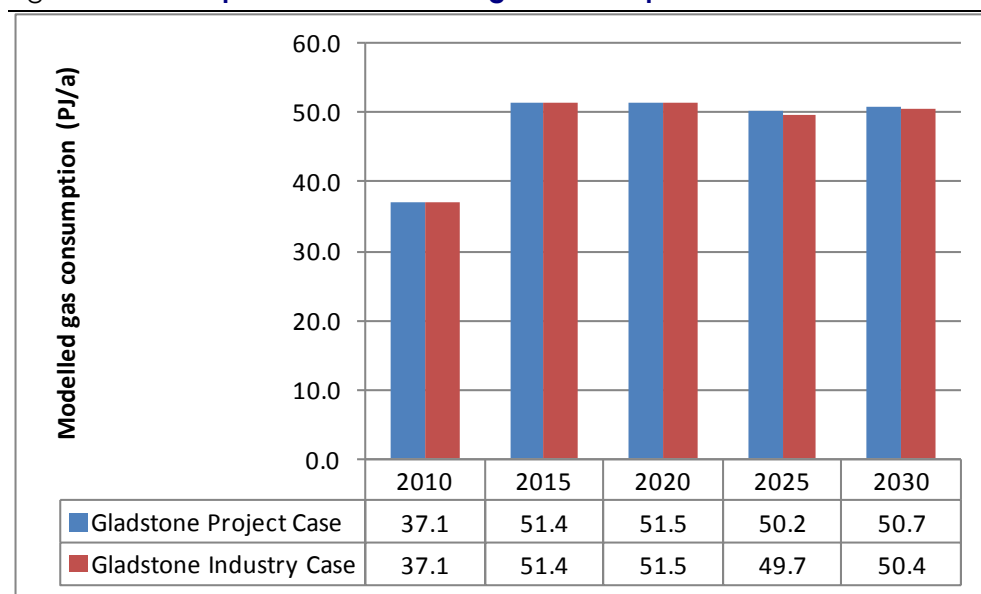
	2011	2015	2020	2025	2030
Boyne Is. Smelter	1.4	1.4	1.4	1.4	1.4
Orica - NaCN cholalkali	3.8	3.8	3.8	3.7	3.7
Orica NH ₄ NO ₃ expansion	0.0	2.8	2.8	2.8	2.8
Comalco - Calcining	4.1	4.1	4.1	4.0	4.0
QAL Alumina Plant	13.2	13.3	13.7	13.4	13.1
QAL - Alumina Plant Expansion	0.0	5.1	5.0	5.0	5.0
Gladstone Base Market	0.2	0.2	0.2	0.3	0.3
YAR Stage 2 Calcining	7.4	7.4	7.3	7.3	7.2
Yarwun Cogen	6.9	13.3	13.1	11.8	12.9
TOTAL	37.1	51.4	51.5	49.7	50.4

Note: ACIL Tasman GMG Australia modelling; totals may not add due to rounding

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

As shown in Figure 11, there is very 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” after 2020, reflecting the increased LNG output and higher wholesale prices which impact on domestic consumption. The differences, however, are small 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**



Source: ACIL Tasman GMG Australia modelling

2.7.2 Gas prices

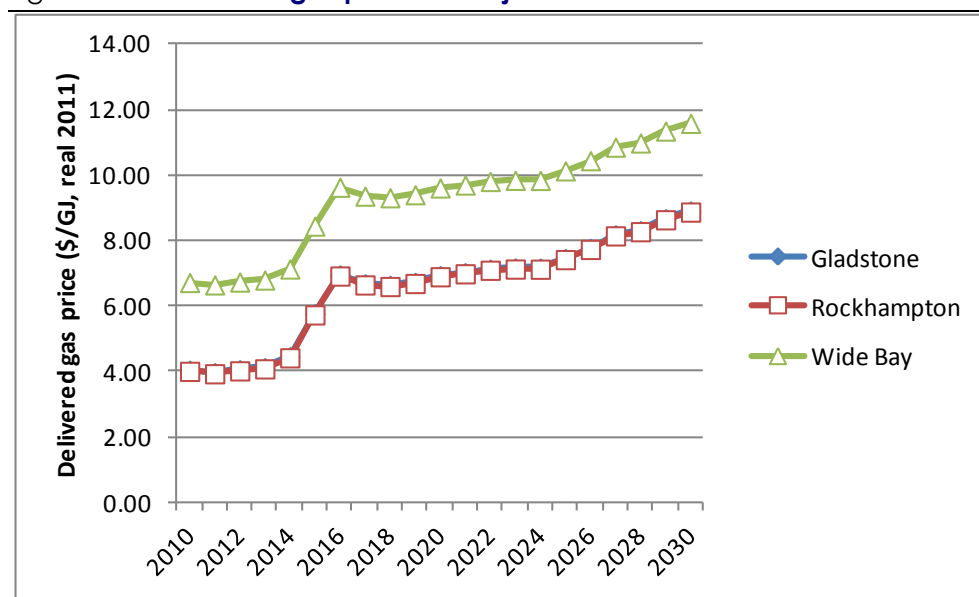
A note on modelled gas prices

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 2011 A\$/GJ terms) under the “Project Case” are illustrated in Figure 12. As shown, real gas prices at the margin tend to remain fairly flat over the period from 2010 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 gas transport from Gladstone via the Wide Bay Transmission Pipeline. Because the Wide Bay Transmission 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 cost of transport on the Wide Bay pipeline. Details of modelled wholesale delivered prices, by regional market, for the “Project Case” 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 2011 A\$/GJ, delivered)**

	Gladstone	Rockhampton	Wide Bay
2010	4.04	4.00	6.72
2011	3.97	3.93	6.65
2012	4.05	4.02	6.73
2013	4.11	4.08	6.79
2014	4.45	4.42	7.13
2015	5.76	5.73	8.44

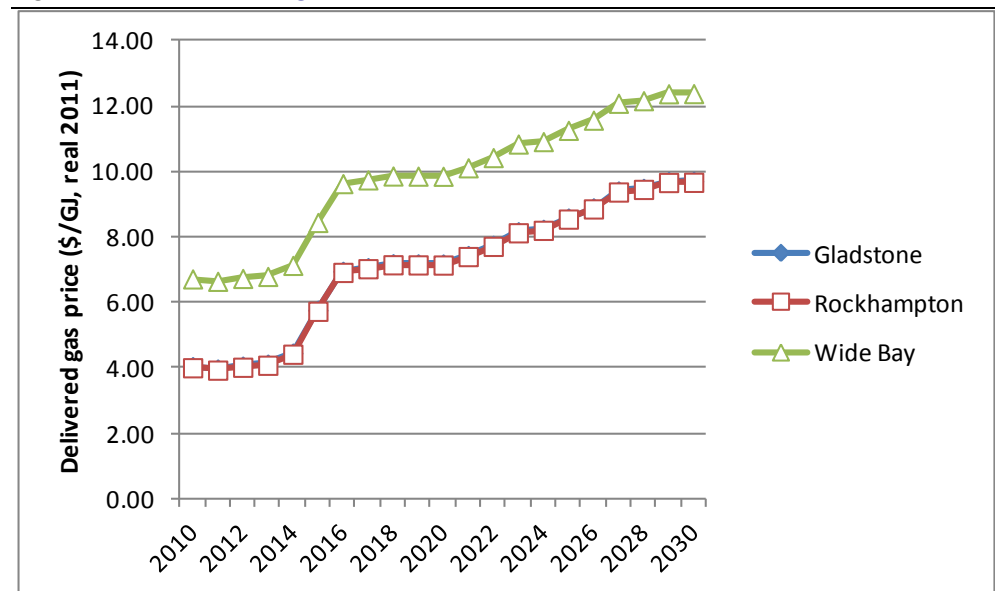
2016	6.95	6.92	9.63
2017	6.68	6.64	9.36
2018	6.63	6.60	9.31
2019	6.72	6.69	9.40
2020	6.93	6.90	9.61
2021	7.02	6.99	9.70
2022	7.13	7.09	9.81
2023	7.16	7.13	9.84
2024	7.16	7.13	9.84
2025	7.45	7.42	10.13
2026	7.76	7.73	10.44
2027	8.18	8.14	10.86
2028	8.30	8.27	10.99
2029	8.67	8.64	11.35
2030	8.90	8.87	11.59

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 13 and detailed in Table 10.

Figure 13 **Modelled gas prices—“Industry Case”**



Source: ACIL Tasman GMG Australia modelling

Table 10 **Modelled wholesale gas prices, by regional market—"Industry Case" (Real 2011 A\$/GJ, delivered)**

	Gladstone	Rockhampton	Wide Bay
2010	4.04	4.00	6.72
2011	3.97	3.93	6.65
2012	4.05	4.02	6.73
2013	4.11	4.08	6.79
2014	4.45	4.42	7.13
2015	5.76	5.73	8.44
2016	6.95	6.92	9.63
2017	7.06	7.03	9.75
2018	7.18	7.15	9.87
2019	7.18	7.15	9.86
2020	7.18	7.14	9.86
2021	7.44	7.40	10.12
2022	7.75	7.71	10.43
2023	8.16	8.13	10.84
2024	8.24	8.20	10.92
2025	8.58	8.55	11.26
2026	8.89	8.86	11.57
2027	9.41	9.38	12.09
2028	9.49	9.45	12.17
2029	9.70	9.67	12.38
2030	9.70	9.67	12.38

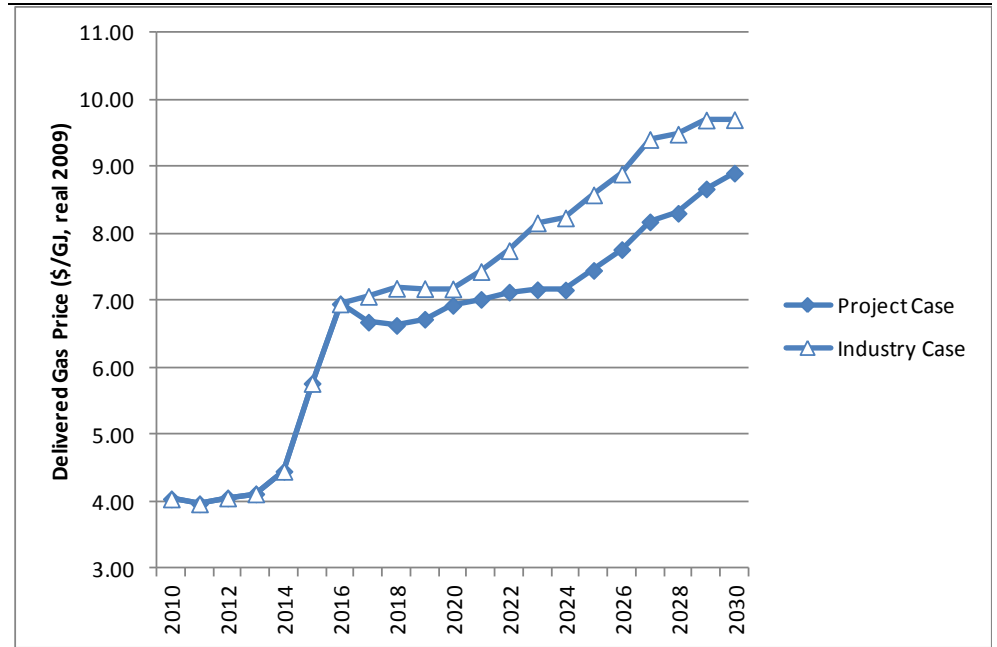
Data source: ACIL Tasman GMG Australia modelling

Gas price comparison – Gladstone

As shown in Figure 14, modelled prices under the "Project Case" are initially identical to those for the "Industry Case", remaining relatively flat in real terms until the commencement of CSG LNG production which ramps up from 2014. This reflects the fact that the supply cost curve assumptions and the assumed ramp up profiles of CSG reserves and production capability in the Surat and Bowen Basins are the same in both cases. However, following start-up of LNG production, modelled prices under the "Industry Case" rise rapidly to levels significantly above the "Project Case" prices, reflecting the increased production capacity assumed for the "Industry Case". Following commissioning of the LNG plants, there is an upward shift in prices reflecting the introduction of additional LNG production capacity 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 14 **Comparison of modelled wholesale gas prices delivered at Gladstone**



Source: ACIL Tasman GMG Australia modelling

3 LNG market projections to 2030

Chapter Summary

Australia currently ranks fifth in the world with respect to installed LNG capacity. In 2010 Australia had 19.3 Mtpa of operational LNG liquefaction capacity, accounting for 7% of the world total. By end 2015, Australia is forecast to have installed LNG capacity of 55.4 million tonnes or 16% of the world total, and in the longer term Australia is projected to surpass Qatar as the largest LNG exporter.

Since early 2007, at least six LNG projects based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been proposed. Four projects are being actively pursued, including three which have reached Final Investment Decision and are now under construction. Six LNG trains with total capacity of 25.3 Mtpa have been committed. Total installed capacity could reach almost 60 Mtpa if the projects are developed to their full announced potential sizes.

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

The following are the most advanced project proposals:

- Queensland Curtis LNG (BG Group/CNOOC): two LNG trains initially, each with nominal capacity of 4.25 Mtpa, with the first on line late 2014, second during 2015. A third train, of similar size, is proposed but timing is uncertain.
- Gladstone LNG (Santos/Petronas/Total/KOGAS): First two trains (total 7.8 Mtpa) committed with first LNG from early 2015; potential for three trains up to 10 Mtpa.
- APLNG (Origin/ConocoPhillips/PetroChina): First train of 4.5 Mtpa committed in July 2011; second train (also 4.5 Mtpa) committed July 2012. Targeting first production in 2015; with second train commencing shipments in 2016. Announced potential for up to four LNG trains.
- Arrow LNG (Shell/Arrow, Sinopec) working toward a final investment decision for one or two trains (each 4 Mtpa) during 2013. First gas possible by 2017. Announced potential for up to four LNG trains.

3.1 Australia's role in global LNG markets

Australia currently produces approximately 1.5% of the world's gas and in 2010 ranked as the eighteenth largest gas producing nation.⁶ At present, about half of Australia's gas production is used domestically while half is exported. However, Australia currently ranks fifth with respect to installed LNG capacity⁷. In 2010 Australia had 19.3 Mtpa of operational LNG liquefaction capacity, accounting for 7% of the world total 271 Mtpa.⁸

⁶ Based on data presented in the BP Statistical Review of World Energy 2011, p.22.

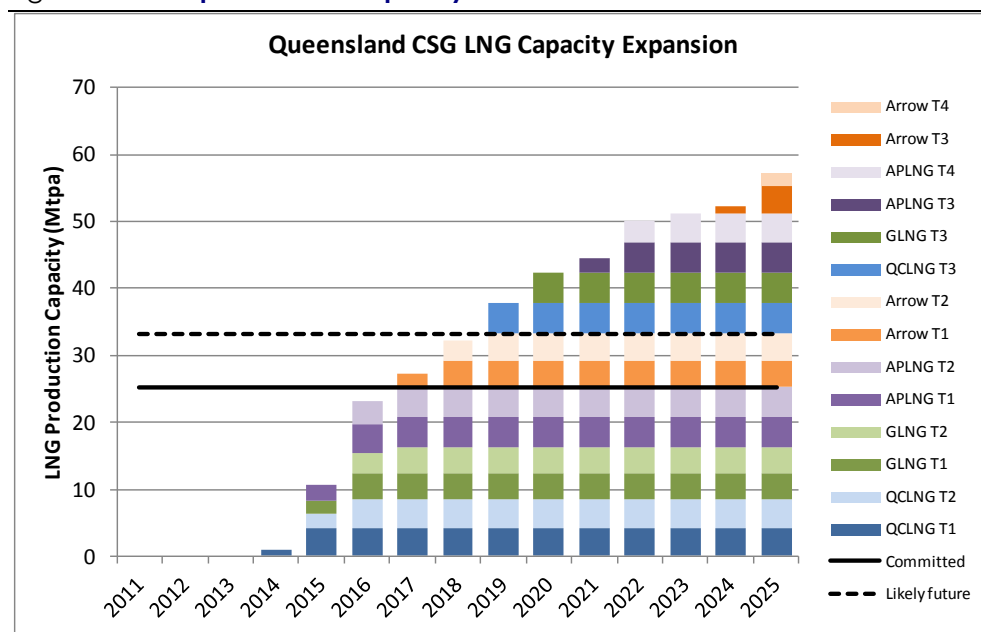
⁷ International Gas Union, 2010: *IGU World LNG Report 2010*, p.15.

⁸ International Gas Union, 2010: *IGU World LNG Report 2010*, *ibid*.

International trade of gas in the form of liquefied natural gas (LNG) continues to grow, as does Australia's share of that industry. In its 2011 Gas Statement of Opportunities, the Australian Energy Market Operator (AEMO) noted that twelve LNG projects are currently under construction around the world, of which seven are located in Australia. By end 2015, the International Gas Union World LNG Report 2010 forecast Australia to have installed LNG capacity of 55.4 million tonnes (including 16.8 Mtpa at Gladstone) or 16% of a global total of 344 Mtpa. That forecast included QCLNG (two trains: 8.5 Mtpa) and GLNG (two trains: 7.8 Mtpa) but did not include APLNG at Gladstone (two trains now confirmed for a total 9 Mtpa capacity). In the longer term Australia is projected to surpass Qatar as the world's largest LNG exporter.⁹

Based on the announced plans of the four main Gladstone LNG project proponents, LNG production capacity at Gladstone could exceed 60 Mtpa by 2030—see Figure 15. This does not include the proposal by LNG Limited to construct up to 3 Mtpa of LNG capacity at Fisherman's Landing, north of Gladstone.

Figure 15 **Proposed LNG capacity at Gladstone**



Notes: Includes four main LNG projects only; timing of expansion trains is indicative only

Data source: ACIL Tasman compilation of information contained in proponent public documents

The total modelled gas requirements for LNG production at Gladstone under the Project Case and Industry Case are summarised in Table 11. Under the Industry Case total gas consumption for LNG production begins to decline

⁹ International Gas Union, 2010: *IGU World LNG Report 2010*, p.35 and Appendix 2.

after 2025 because some gas that would otherwise be used for LNG production is diverted to the domestic market

Table 11 **Gas use for LNG Production at Gladstone: Project Case and Industry Case**

	2015	2020	2025	2030
Project Case	729	1,260	1,260	1,260
Industry Case	729	1,915	1,915	1,841

Note: Gas consumption in PJ/a; includes auxiliary gas requirements for compression and processing,

Data source: ACIL Tasman GMG Australia modelling

According to the Bureau of Resource and Energy Economics (BREE), Australia exported 18.9 million tonnes of LNG in calendar year 2011, valued at \$11.1 billion.¹⁰ Australian exports of LNG have increased strongly over the past 20 years, and have risen particularly rapidly over the past five years. Exports of approximately 25 million tonnes are expected for 2011-2012. BREE predicts that the rate of growth will accelerate, with natural gas exports reaching 63 million tonnes per year by 2016-17, an annual growth rate of more than 21%¹¹. Most of this growth is expected to come from increased production from projects in the North West Shelf region of Western Australia, the Conoco-Phillips LNG plant and proposed Ichthys LNG plant at Darwin and the Gladstone LNG projects. More Western Australian operations are in the development phase, including the Pluto, Gorgon and Wheatstone projects in the Carnarvon Basin and several in the Browse Basin.

The majority of the world's large importers of LNG are in the Asia Pacific region, giving Australia a natural advantage in terms of the relatively short distances to these key markets.

3.2 LNG in Eastern Australia

Until recently, Eastern Australia had 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, changed the prospects for East Coast LNG. Over the period 2007 to 2009, several LNG proposals based on coal seam gas (CSG)

¹⁰ Bureau of Resource and Energy Economics, 2012a: *Resources and Energy Statistics, December quarter 2011*.

¹¹ Bureau of Resource and Energy Economics, 2012b: *Resources and Energy Quarterly, March quarter 2012, Table 3*.

feed from the Bowen and Surat Basins were announced. Four of these have now progressed to committed or advanced projects.

The four committed and advanced projects are all world-scale, potentially multi-train projects with individual trains ranging from 3.9 to 4.5 million tonnes per year capacity. Total capacity already committed and under construction as at the date of this report is 20.8 Mtpa. Total installed capacity could reach almost 60 Mtpa if the projects are developed to their full announced potential sizes.

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.

The following sections summarise the current active CSG LNG projects.

3.2.1 Queensland Curtis LNG (QCLNG)

In October 2010 BG/QGC made a final investment decision on a two-train, 8.5 Mtpa development of the QCLNG project. Contracts have been let for some long lead items; the large diameter export pipeline has been fabricated in China and delivered to Gladstone; and the project is now well into construction. First LNG shipments are scheduled for late 2014. There is scope for QCLNG to add a third liquefaction train subject to further reserves definition within the BG/QGC areas or introduction of third-party gas reserves. In October 2012 BG Group announced the sale of an interest in the QCLNG project to China National Offshore Oil Corporation (CNOOC).

3.2.2 Gladstone LNG (GLNG)

The Santos/Petronas/Total/KOGAS consortium reached a final investment decision in relation to the first two trains of the GLNG project in January 2011. The development approval triggered major works on upstream field development, pipelines and construction of a 7.8 Mtpa two-train LNG facility at Gladstone. First LNG shipments are scheduled in 2015. There is potential for addition of a third train to the GLNG project, subject to identification of sufficient CSG reserves and securing customers for the additional LNG volumes.

3.2.3 Australia Pacific LNG (APLNG)

In April 2011 APLNG completed binding agreements with Sinopec of China for the sale of 4.3 Mtpa of LNG over 20 years. Sinopec has also taken a 15% equity interest in the project. The deal effectively accounted for all production from the first train of the project which was subsequently committed under a

final investment decision (FID) taken in July 2011. First LNG production from Train 1 is scheduled in mid 2015. APLNG took FID on Train 2 in July 2012, with first LNG production from Train 2 expected by early 2016.

3.2.4 Arrow LNG (ALNG)

The Arrow LNG Project (ALNG; Shell/PetroChina) is targeting development in two stages with a nominal capacity of 16 Mtpa of LNG, with potential for up to 18 Mtpa. Under current plans, the first stage of the project will see the construction of two LNG trains with a nominal capacity of 4 Mtpa which will begin producing LNG in 2017 and 2018 respectively. Construction of the third and fourth trains is expected to commence five years after the completion of stage 1, although the timing will depend on market conditions and project financial decisions. The ALNG consortium is looking to take a final investment decision on the first stage of the project in 2013 or 2014.

3.2.5 Fisherman's Landing LNG (FLLNG)

Liquefied Natural Gas Limited (LNG Limited) is proposing to construct a mid-scale LNG plant of up to 3 Mtpa capacity (two trains each of 1.5 Mtpa) at Fisherman's Landing, situated on the mainland about 10 km north of Gladstone opposite Curtis Island. LNG Limited has undertaken extensive engineering and other studies but does not currently have access to a source of gas sufficient to support the project. A final investment decision on FLLNG is very unlikely to be taken unless and until a suitable source of gas can be secured.

4 Small gas producer assessment

Chapter Summary

This chapter considers the question whether other CSG or conventional gas producers in the vicinity of the GLNG Gas Transmission Pipeline would be likely to benefit significantly from having access to the pipeline. The analysis focuses on those small or emerging gas 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 gas within their exploration areas.

The analysis has identified three companies not currently involved in LNG proposals that have CSG or conventional resources or exploration areas prospective for gas located within 100 km of the GLNG Gas Transmission Pipeline.

However, none of these resource and prospect holders are likely to find that access to the GLNG Gas Transmission 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 equal distance from the QGP (via the Dawson Valley Pipeline) or closer to the RBP. Two of the three companies in question already produce and sell CSG with transport provided by existing pipeline infrastructure (Dawson Valley Pipeline, Queensland Gas Pipeline).

Other factors mitigating against third party use of the GLNG Gas Transmission 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 likelihood that the GLNG Gas Transmission 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 gas explorers and producers in the vicinity of the GLNG Gas Transmission Pipeline and associated facilities 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 the interactive resource and tenure map provided by DEEDI to identify small gas explorers and producers in the vicinity of the GLNG Gas Transmission Pipeline.

4.1 Small independent producers

This section looks at the potential for natural gas production by small independent producers and tenement holders in the vicinity of the GLNG Gas Transmission Pipeline. The area of interest for this investigation is identified as a corridor extending 100 km from the GLNG Gas Transmission Pipeline, from south of Fairview to the LNG facility on Curtis Island (see Figure 16). Within that corridor, all exploration tenements not currently controlled by the proponents of the four major CSG LNG projects at Gladstone have been 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 analysis identified three ASX listed companies not directly involved in the LNG projects that hold interests in tenements within the 100 km corridor, namely:

- Molopo Australia Limited (now owned by PetroChina) (Map Reference 1)
- Westside Corporation (Map Reference 2)
- Blue Energy Limited (Map Reference 3)

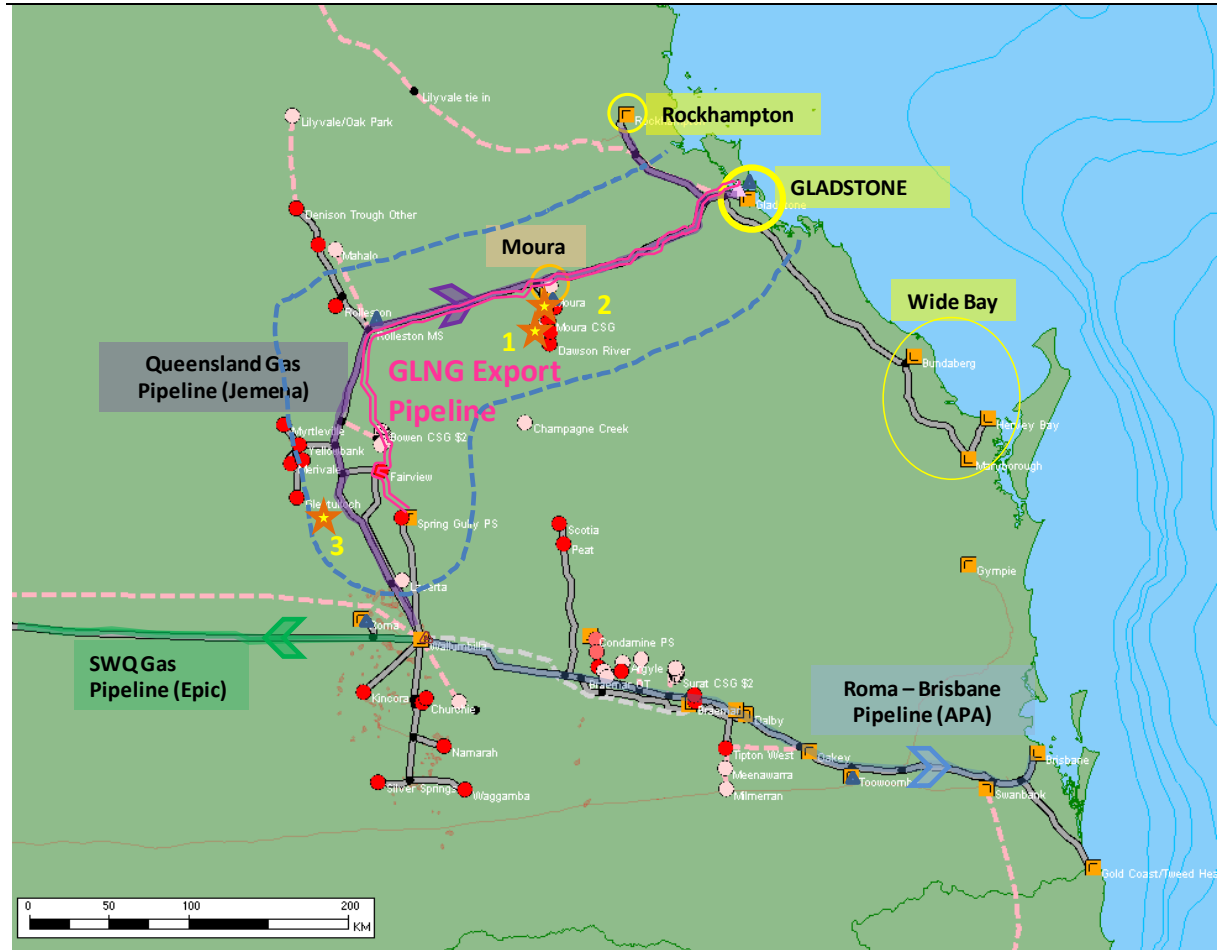
Bow Energy, which also holds tenements within the 100 km corridor, was taken over by Arrow Energy in December 2011 and is therefore now involved with the Arrow LNG project. Bow Energy's CSG prospects are therefore not considered further in this analysis. The interests of Molopo, Westside and Blue Energy are summarised in Table 12, and the locations of their interests are illustrated in Figure 16.

Table 12 **Summary of small independent CSG prospects proximate to GLNG**

Map Ref	Holder	ATP	Prospect	Comments
1	Molopo/ PetroChina	564, 602; 447, PL 94, PLA 210	Dawson Valley	Current production through existing Dawson Valley infrastructure
2	Westside	Moura coal mining leases	Meridian Seamgas Project; Moura	Assets acquired from Anglo Coal; Current production through existing Dawson Valley infrastructure.
3	Blue Energy	817 (Central), 854	Injune district	Early stage exploration areas, no certified reserves.

Data source: DEEDI, Queensland Government website

Figure 16 Location of small independent CSG prospects proximate to GLNG



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

Both the Molopo and Westside projects referred to in Table 12 are already in production, servicing customers at Moura and Gladstone via existing transport arrangements on the Dawson Valley Pipeline and Queensland Gas Pipeline.

There are also a number of independent CSG companies that hold exploration tenements that are more than 100 km from the southern terminus of the GLNG Gas Transmission Pipeline, but within 100 km of other upstream facilities operated by GLNG. These tenements are not considered further in this analysis because the GLNG facilities in question are outside the corridor of the Pipeline and are not included in the No Coverage Application.

The following sections discuss in turn each of the relevant prospects within the Pipeline corridor.

4.1.1 Molopo, Dawson Valley Production Areas (Map Ref 1)

Molopo currently produces and sells CSG (0.53 PJ in 2011), delivering gas to Central Queensland customers via the Dawson Valley Pipeline. Molopo is also developing a proposal for a 60 MW power station near Moura that would use CSG from its Dawson Valley Production Area.¹²

Molopo's principal gas interests in Queensland are in CSG exploration, development and production in the Dawson Valley. The Company has a 67% interest in each of the Mungi CSG Project [PL 94-Northern Section], Harcourt/Bindaree [ATP 564P/PLA 210], the Timmy Project [ATP 602P] and the Theodore South Project [ATP 564]. Molopo's partner in these tenures is Mitsui E&P Australia Pty Ltd.

The Mungi CSG Gas Field is located near Moura and west of Anglo's Dawson Valley coal mines. Gross gas production at Mungi in 2011 remains at around 2-3 million cubic feet per day with an estimated total production of 788 TJ for the 2010-11 financial 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 25 km of the proposed GLNG Gas Transmission 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, with an existing connection to the QGP. The distance of the project to the QGP stands approximately at 25 km. Because of the distances involved, as well as the technical issues involved in upgrading the Dawson Valley system to make it compatible with GLNG Gas Transmission Pipeline, gas produced by Molopo from these areas, targeting the Central Queensland gas market, is most likely to utilise the existing Dawson Valley gas infrastructure and the QGP.

In August 2012 Molopo sold its Bowen Basin CSG assets to PetroChina International Investment (Australia) Pty Ltd. PetroChina Australia's stated intention is to deliver the Molopo gas, under a tolling arrangement, to LNG Ltd's proposed 3 million tonne per annum LNG project at Fisherman's Landing, Gladstone.

¹² Molopo Energy Annual Report 2011, p. 13.

4.1.2 Westside Corporation Meridian Seamgas (Map Ref 2)

The Meridian SeamGas fields comprise a range of CSG assets including a petroleum lease (PL94), gas rights in mining leases, some 70 producing wells and gas compression and pipeline infrastructure connected to Queensland's commercial gas network and Gladstone via the Dawson Valley Pipeline and Queensland Gas Pipeline. Westside currently produces and sells around 3.2 PJ/a of CSG from the Meridian Seamgas project.

In mid-2010 Westside Corporation completed the acquisition of a 51% interest in the Moura CSG Production Areas from Anglo Coal [Moura] Limited, a subsidiary of Anglo Coal Australia Pty Ltd. Now renamed the Meridian Seamgas Project, the assets are operated by Westside in a joint venture with Mitsui E&P Australia Pty Ltd. Production of CSG at the Meridian project comes largely from coal leases in the Dawson Valley, south of Moura.

Westside also holds a 25.5% interest in the adjacent Paranaui CSG field together with Mitsui (24.5%) and QGC (50%). The involvement of QGC in this area means that production from Paranaui is most likely to be directed into the QGLNG project. Any further expansion in CSG production from the Meridian Seamgas areas is likely to be carried through the existing connections to the Dawson Valley Pipeline and QGP.

4.1.3 Blue Energy, Oakey & Millmerran Prospects (Map Ref 3)

Blue Energy has a number of tenement areas located in the Surat Basin, including some areas proximate to the GLNG Gas Transmission Pipeline and other GLNG upstream assets.

ATP's 854 and 817 (Central) are located around Injune, in between or adjacent to tenements held by GLNG. These are early stage exploration areas estimated by the company to contain significant gas-in-place but with no certified reserves as yet. The Queensland Gas Pipeline (QGP) is the closest existing pipeline to these areas, and is around 50 km closer than Fairview, at the southern end of the GLNG Export Pipeline. Targeting markets in Gladstone via the GLNG Gas Transmission Pipeline may require pre-treatment of CSG to meet GLNG gas specification requirements.

The ATP 817 P (South) area is located more than 100 km southwest of the GLNG Gas Processing Plant site at Wallumbilla. ATP 818, 819 and 896 lie in the eastern and southern Surat Basin, even further from the GLNG facilities, and are not considered further for the purposes of this analysis.

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, but these areas are far distant from the GLNG facilities and hence not relevant to this analysis.

4.2 Other considerations

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

- **Short-term and/or interruptible capacity:** Because the GLNG project is likely to require all of the initially installed capacity in the Export Pipeline for the two liquefaction trains currently sanctioned, transport services in the initial system 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. Access to firm capacity on the pipeline would require the pipeline owners to increase capacity on the GLNG Gas Transmission Pipeline by installing mid-line compression. The high cost of mid-line compression would need to be offset by large throughput volumes that are only likely to be achieved if GLNG decides to build a third LNG train—a decision that has not yet been made.
- **Offtake facilities:** The GLNG 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 GLNG Gas Transmission Pipeline from their production facilities.
- **Gas quality issues:** CSG from different gas fields, and from conventional gas, can be used interchangeably in most production processes provided the gas complies with AS 4564 Australian Standard Specification for General Purpose Natural Gas. To be economical however, liquefied natural gas facilities are usually designed for gas of a much narrower gas specification, based on the expected composition of the gas intended to be supplied to the facility. The LNG Facility, including contaminant limit levels and removal units (eg acid removal units and mercury removal units) has been designed for feed gas of the average specification expected to be produced at the Gas Fields, [Confidential]

GLNG will be acquiring some gas for the GLNG project from third

parties. It will also have to store gas, including CSG, from time to time (particularly during the ramp up period) at its Roma Underground Gas Storage facility. GLNG will construct the Treatment Facility if necessary to ensure that all gas purchased from third parties by GLNG or stored in the Roma Underground Gas Storage facility meets the specification and contaminant design limits before it is injected into and transported through the Pipeline to the LNG Facility.

CSG originating from fields other than the Gas Fields (ie third party gas) is unlikely to meet the narrow LNG Facility gas specification design limits without treatment. Any conventional gas is highly unlikely to meet design limits without treatment. Unless treated prior to entering the Pipeline to meet the design limits, any third party gas transported in the Pipeline exceeding the design limits will come in line with and contaminate CSG from Gas Fields (and other third party gas treated by GLNG). Consequently, other third parties seeking access to the Pipeline may need to process their gas to meet the narrow specification required by LNG Facility before delivering it into the Pipeline.

4.3 Conclusions regarding small, independent CSG producers

Based on this analysis, none of the small independent CSG tenement holders within 100 km of the proposed GLNG Gas Transmission 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 similar distance to either the QGP (directly or via the Dawson Valley Pipeline) or closer to the RBP. Other factors mitigating against third party use of the GLNG Gas Transmission Pipeline include the short term and/or interruptible nature of the services that could potentially be made available; the need for installation of mid-line compression to provide additional firm capacity; the need for the third party shipper/s to meet capital costs of offtake facilities; and the fact that the GLNG Gas Transmission Pipeline will carry gas of a more exacting specification than the general Australian Standard for sales gas. Molopo and Westside have existing gas sales agreements for supply at Moura and in Gladstone (via the Dawson Valley Pipeline and QGP). These agreements demonstrate that the small independent CSG explorers in the vicinity of the GLNG Gas Transmission Pipeline and other upstream assets currently have practical options for delivering their gas to markets.

5 QGP transport cost assessment

Chapter Summary

This chapter provides information on the 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 users with contracts entered into prior to introduction of the National Gas Law, charges on the pipeline are currently limited by a rate cap of A\$0.795/GJ of capacity reserved (now reduced to A\$0.71/GJ after 2010 capacity expansion). For new users, the charge for firm capacity is currently A\$0.8993/GJ (as at 1 January 2012). Tariffs are indexed by CPI on 1 January each year. No more than 5 TJ/d of firm capacity is currently available; additional firm capacity would require further expansion of the pipeline system.

As Available Transport Service (interruptible) is offered at rates varying according to receipt point and delivery point. For full line transport from Wallumbilla to Gladstone, the As Available haulage rate is currently about \$1.53/GJ for each unit of gas delivered.

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: Jemena (<http://jemena.com.au/what-we-do/assets/queensland-gas-pipeline/>)

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 firm capacity contracts for 145 TJ/d of capacity (around 53 PJ/a at 100% load factor) and transports gas to major industrial facilities including:

- Queensland Alumina
- Rio Tinto Yarwun
- Orica
- Queensland Magnesia
- Boyne Smelter
- Queensland Energy Resources

It also supplies gas to Origin Energy for on-selling to domestic, commercial and residential users.

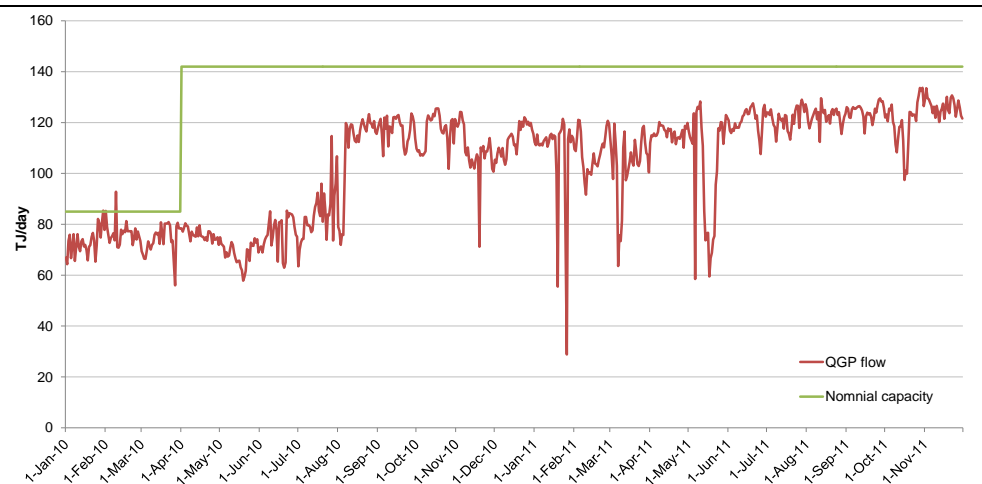
Most of the market for QGP is assured through long term firm forward contracts until 2016/17 with some capacity contracted to 2021.

5.1.2 Pipeline capacity and flow

The pipeline's current capacity stands at 145 TJ/day. A pipeline expansion in capacity in early 2010 increased the capacity by 49 TJ/day. The expansion involved both looping and compression—at a cost of A\$112m—to increase capacity to 52 PJ/a. The additional compressors are located at Rolleston and Banana, and pipeline looping will occur from Moura to Bell Creek.

Figure 18 shows the historical flows on the QGP over the two-year period from January 2010 to December 2011. Over this period, average throughput on QGP rose from around 70 TJ/day to 125 TJ/day, primarily as a result of increased deliveries to the Rio Tinto Yarwun alumina refinery. Based on its current capacity of approximately 145 TJ/day, the system average load factor is high at around 86% reflecting the fact that major customers are large process industries.

Figure 18 **QGP throughput January 2010 – December 2011**



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

Nearly all of the additional capacity created on the QGP as a result of the 2010 expansion has already been taken up by new contracts. Most of this additional capacity has been contractually committed to service the expanded gas requirement of Rio Tinto for the Yarwun Stage 2 project – a 122.5 MW gas – fired cogeneration unit. According to Jemena's website there is currently no more than 5 TJ/day of uncontracted firm capacity available on the pipeline.

Further expansion may be undertaken to meet the needs of new customers. A recent study has confirmed that large increases to the existing capacity would be feasible. During 2011, Jemena completed a Pre-Front End Engineering Design (Pre-FEED) to assess the viability of expanding the QGP system to carry the gas feed for the FLLNG project proposed by LNG Limited (for a short discussion of the FLLNG project see section 3.2.5). The study showed

that the pipeline could be expanded to supply enough gas by 2014 for a 1.5 Mtpa LNG train and by 2015 a second LNG train. Given that 3 Mtpa of LNG equates to about 165 PJ, this implies that the QGP system is capable of expansion to at least 215 PJ/a.

5.1.3 Transportation tariffs

The QGP was previously a covered pipeline under the *National Third Party Access Code for Natural Gas Pipelines* ('Gas Code') and was required to have an approved Access Arrangement. The tariffs under the Access Arrangement were the subject of a derogation following the Queensland Government's sale of the QGP in 1996 and the introduction of the Gas Code in 1997.

The Gas Code has, pursuant to the *National Gas (Queensland) Act 2008 (Qld)* and the *National Gas (South Australia) Act 2008 (SA)*, been replaced by the National Gas Law ('NGL') and the National Gas Rules ('NGR').

The introduction of the NGL and NGR means that the QGP is no longer a covered pipeline for the purposes of third party access regulation. With the removal of coverage the Access Arrangement published pursuant to the Code no longer applies to new access agreements. Different tariffs apply for existing shippers with transportation contracts in place prior to the introduction of the 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, 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/GJ¹³
- 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).

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.

¹³ Tariff escalation provisions allow for an increase to the capacity reservation rate of \$0.04 on 1 July 2011, 2016, 2021, 2026 and 2031.

Table 13 **QGP transportation tariffs for pre-NGL contracts**

	Units	Before expansion date (<25 PJ)	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

Post-NGL shippers

Following the introduction of the NGL 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.¹⁴

The tariffs offered to post-NGL shippers are set out in Table 14.

Table 14 **QGP transportation tariffs for post-NGL shippers**

Firm Gas Transport Service						
Capacity Tranche	Currently available		Tariff	Comments		
0 -145 TJ/d	0		n/a	Fully contracted		
145+ TJ/d	1 - 5 TJ/d*		0.8993	Available; actual available capacity varies depending on path contracted		
As Available Transport Service						
Receipt Point	Wallumbilla		Goomiba Lacerta	Fairview Westgrove	Rolleston	Moura Inlet
Delivery Point						
Rockhampton	1.6128		1.4875	1.4675	1.2881	1.1316
Gladstone	1.5274		1.4020	1.3822	1.2028	1.0463
Yarwun	1.5059		1.3806	1.3606	1.1812	1.0247
Moura	1.3011		1.1759	1.1559	0.9765	n/a
Wallumbilla	n/a		Refer Backhaul	Refer Backhaul	Refer Backhaul	Refer Backhaul
Backhaul Service (delivery to Wallumbilla)	n/a	0.5203	0.5203	0.5203	0.5203	

Data source: Jemena

¹⁴ Jemena website, accessed 14 October 2011

A capacity charge of \$0.8993/GJ (as at 1 January 2012) 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.

On this basis, the effective cost to transport gas on QGP to service a customer with an 80% load factor under a new firm gas transportation contract would currently be about \$1.12/GJ of gas delivered.

Table 15 QGP Gas Transmission Pipeline tariffs

Transportation task	Tariff
FFH Transport @ 100% Load Factor	\$0.8993
FFH Transport @ 80% Load Factor	\$1.1241

Data source: ACIL Tasman analysis

As available (interruptible) transportation is offered at rates of between \$0.98/GJ and \$1.61/GJ of gas delivered, the applicable rate being determined by the location of the receipt and delivery points (see Table 14). For full line transport from Wallumbilla to Gladstone, the As Available haulage rate is currently about \$1.53/GJ delivered. Because interruptible service does not involve firm capacity reservation, effective rates per GJ delivered do not vary with customer load factor.

6 CSG LNG transportation cost assessment

Chapter Summary

This chapter provides an assessment of the average real and levelised tariffs that would be required to yield a commercial rate of return on the GLNG Export Pipeline, operated on a standalone basis. The analysis considers both the two-train “Project Case” (free-flow) and the 3-train sensitivity (with mid-line compression), and considers tariffs for a project life of 25 years. For the 2-train case, the average real tariff is estimated to be \$1.27/GJ of capacity booked, or \$1.64/GJ on a levelised basis. For the 3-train case, the corresponding tariffs are \$1.15/GJ and \$1.50/GJ respectively.

A 2% change in the discount rate has an impact of around \$0.25 /GJ on the levelised tariff under the 2-train case. A 10% change in pipeline capital cost has an impact of around A\$0.07/GJ on the levelised tariff.

Costs to construct a tie-in from the GLNG Gas Transmission Pipeline to the Gladstone City Gate would depend on the length of the required lateral as well as the required flow rate across the tie-in. Tie-in facility costs are estimated to be about \$5m. The cost of a lateral pipeline connection from GLNG Gas Transmission Pipeline to Gladstone City Gate is estimated at \$0.5 million for a one-kilometre tie-in with a 10" diameter, leading to an all-up tie-in cost of around \$5.5 million. Increasing the length of the required lateral from GLNG Gas Transmission Pipeline to Gladstone City Gate to 10 km would result in the overall capital cost of the tie-in increasing to \$10 million.

Because the GLNG Gas Transmission Pipeline System is not designed or intended for carriage of gas other than LNG feed, there is no explicit tariff for transportation of gas on the system. However, a “shadow tariff” can be estimated on the basis of the expected capital and operating costs of the system, expected gas throughput and the required rate of return on capital. This effectively represents the implied average cost to the GLNG project of transporting gas from the upstream CSG production and processing facilities to the LNG plant at Gladstone, taking into account a return on capital invested. It can therefore be taken as an indication of the tariff that the GLNG participants could reasonably expect a third party user to pay for shipping gas through the system “at the margin”.

The GLNG Gas Transmission Pipeline has been designed as a free flow pipeline capable of supplying the gas required for the first two LNG trains. We have been advised that the full capacity of the pipeline in this configuration is effectively committed to the first two LNG trains. With the addition of mid-line compression, the capacity of the pipeline can be increased to allow transportation of the gas required to supply three LNG trains, and in this configuration there would potentially be some spare capacity available.

GLNG has advised a capital cost for the GLNG Gas Transmission Pipeline System of [Confidential]. Of this amount, [Confidential] is for the pipeline itself and [Confidential] relates to the upstream compression required to maintain the pipeline at operating pressure. The estimate does not include the cost of mid-line compression that would be required to supply a third LNG train.

The assumptions used to develop the shadow tariffs are shown in Table 16.

Table 16 **Assumptions used to derive pipeline tariffs for CSG delivered to Curtis Island**

Capex - P/L (Note 1)	A\$m , \$2012	[Confidential]
Capex - Compressors	A\$m , \$2012	[Confidential]
MDQ per train	TJ/day	592
ACQ per Train	PJ pa	195
Gas tariff escalation	as % CPI	100%
CPI	% pa	2.5%
O&M - P/L, pa	as % Capex	[Confidential]
O&M - Compressors, pa	as % Capex	[Confidential]
Discount rate	Real pre-tax	14.3%

Note 1: P/L capex profile [Confidential]

Data source: ACIL Tasman; with MDQ/ACQ, capex and opex from GLNG

In estimating the tariffs, we have assumed a requirement to earn a 10% real post-tax rate of return, corresponding to a 14.3% real pre-tax¹⁵, without any assumptions for specific variables required for a formal WACC calculation.

An average pipeline load factor of 100% has been assumed so that the resulting tariffs are expressed on a “\$/GJ of MDQ” basis.

Shadow tariffs have been calculated on the basis of two scenarios:

1. The currently approved 2-train development (7.8 Mtpa), which does not include the capital cost of mid-line compression that would be required if a third train were to be constructed. The ramp-up to full ACQ has been assumed by ACIL Tasman to see Train 1 operating at 75% capacity in 2015 and 100% capacity thereafter, with Train 2 at 25% capacity in 2016 and 100% thereafter.
2. A 3-train development (10 Mtpa), which includes an assumed capital cost of [Confidential] for mid-line compression that would be required if a third train were to be constructed. The ramp-up to full ACQ has been assumed by ACIL Tasman to see Train 1 operating at 75% capacity in 2015 and

¹⁵ Pre-tax real discount rate = post-tax real rate/(1-tax rate)

100% capacity thereafter; Train 2 at 25% capacity in 2016 and 100% thereafter; and Train 3 at 100% capacity from 2020.

Box 1

Note on levelised tariff

A pipeline tariff can be expressed in several ways, including nominal, real and levelised. A commonly used convention for tariff modelling of gas pipelines is the levelised tariff which is calculated as the ratio between the present value of projected nominal capital and operating costs of the pipeline (with compressors if applicable) and the present value of the projected annual gas demand (MDQ*365.25).

Levelised tariff (A\$/GJ) = PV (Costs)/PV (Annual Gas Capacity or MDQ*365.25)

Data source: Fane S., J. Robinson, S. White, "The Use of Levelised Cost in Comparing Supply and Demand Side Options"

6.1 Results

The tariff analysis for 25 years for the 2-train and 3-train LNG cases for both real and levelised tariffs are shown in Table 17. Note that these tariffs are based on a load factor of 100%. The corresponding tariffs calculated for a customer having a load factor of 80% are also shown by way of comparison.

Table 17 **GLNG Gas Transmission Pipeline estimated tariffs**

	25 yrs	
Results	2 Train	3 Train
Levelised tariff, A\$/GJ @ 100%LF	\$1.64	\$1.50
Levelised tariff, A\$/GJ @ 80%LF	\$2.05	\$1.87
Avg tariff real, A\$/GJ@ 100%LF	\$1.27	\$1.15
Avg tariff real, A\$/GJ@ 80%LF	\$1.59	\$1.43

Data source: ACIL Tasman analysis

The shadow tariffs for the 3-train case are lower than for the 2-train case, notwithstanding the requirement for additional capital (mid line compression) because of the greater gas throughput to supply a 10 Mtpa, 3-train facility compared to a 7.8 Mtpa, 2-train facility.

The estimated shadow tariffs for the GLNG Gas Transmission Pipeline under the 2-train case (current configuration) are significantly higher than the current tariffs on the Queensland Gas Pipeline (QGP). The 100% load factor tariff for new firm capacity on the QGP is currently \$0.8993/GJ or \$1.12/GJ for a customer having a load factor of 80%. The corresponding shadow tariffs for the GLNG Gas Transmission Pipeline are \$1.27/GJ and \$1.59/GJ respectively.

6.1.1 Sensitivity analysis

The sensitivity of the levelised tariff estimates to changes in pipeline capital cost (+/-10%) and discount rate (+/- 2% real, post-tax) for the 2-train case are shown in Table 18.

Table 18 **Sensitivity analysis: impact of pipeline capital cost and discount rate on levelised tariff (2 train; 25 years)**

	as % of assumed capex data				
Discount rate (pre-tax real)	90%	95%	100%	105%	110%
12.3%	\$1.34	\$1.37	\$1.39	\$1.42	\$1.45
14.3%	\$1.57	\$1.61	\$1.64	\$1.67	\$1.70
16.3%	\$1.83	\$1.87	\$1.91	\$1.95	\$1.99

The sensitivity analysis shows that a 2% change in the discount rate has an impact of around \$0.25/GJ on the levelised tariff. A 10% change in the pipeline capital cost has an impact of around \$0.07/GJ on the levelised tariff.

6.2 Costs to tie in to QGP

We have considered what costs would be incurred if a connection were to be made from the GLNG Gas Transmission Pipeline to the QGP system that currently services the Gladstone market (and the sub-regional markets of Rockhampton to the north and Wide Bay to the south). The logical point of connection for any such tie-in would be the existing Gladstone City Gate, located on the north-western side of the city of Gladstone.

Costs to construct a tie-in would depend on the distance of the required lateral from the GLNG Gas Transmission Pipeline and the Gladstone City Gate, as well as the required flow rate across the tie-in. For a flow rate of 4 to 5TJ/hr from 10 MPa to 3.5 MPa (at City Gate) the capital cost is estimated to be about A\$5m covering:

- Metering
- Water Bath Heater
- Pressure reduction
- Knock out pot (removes liquids)
- Filters
- Odourisation (if required)

The cost of the lateral pipeline connection from GLNG Gas Transmission Pipeline to Gladstone City Gate is estimated at \$50,000 per inch-km, hence for a one-kilometre tie-in with a 10" diameter line a capital cost for the pipeline tie-in of A\$0.5 million, leading to an all-up cost for tie in with associated facilities



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of A\$5.5 million. Increasing the length of the required lateral from GLNG Gas Transmission Pipeline to Gladstone City Gate to 10 km would result in the overall capital cost of the tie-in increasing to A\$10 million.

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
- Western Surat Producer B, located 25 km west of the QGP, 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.
- Tariff charges for transportation on existing third-party transmission lines.

For the two model cases, the tie in costs range from \$10.29 to \$28.9 million, with a corresponding unit tariff range of \$0.35 to \$0.38/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 \$0.95/GJ for transport to Brisbane via the Wallumbilla hub, up to \$2.94 /GJ for transport to Sydney.

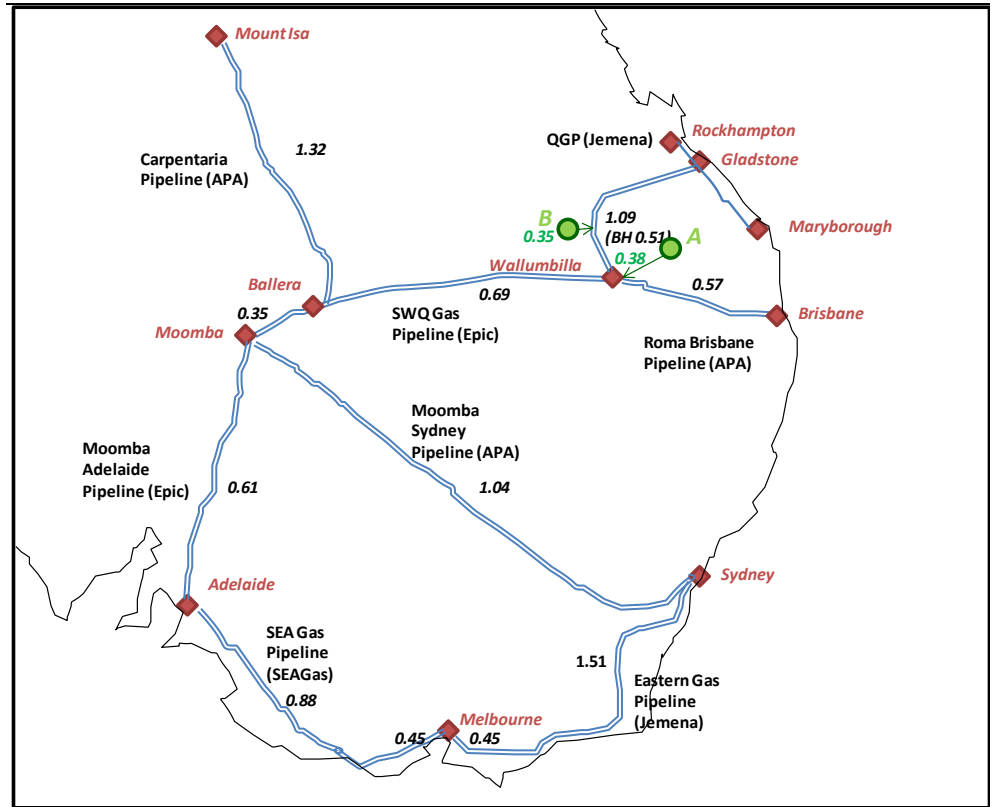
The analysis highlights the fact that CSG producers in the Surat and southern Bowen Basins will generally have options to pursue markets throughout Eastern Australia via the existing gas transmission pipeline network.

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
- Western Surat Producer B, located 25 km west of QGP, 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 2011) 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 19 shows the assumptions and calculations relating to our estimates of the tie-in costs for the two hypothetical CSG producers. The estimated tie-in costs do not include any provision for the cost of compression to raise the third party CSG to the pressure required for injection into the Pipeline. The Pipeline is being designed to operate at pressures up to 10.2 MPa.¹⁶ This is comparable to the QGP which has an inlet pressure operating range of 5.0 –

¹⁶ GLNG Application for Governor-in- Council approval of the GLNG Infrastructure Facility as an Infrastructure Facility of Significance, section 3.1(b).

10.2 MPag.¹⁷ Hence a third party shipper would be likely to face similar costs for gas compression in order to deliver gas into the GLNG Gas Transmission Pipeline or QGP.

Table 19 **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)	23.6	7.09
Metering etc (A\$M)	5.3	3.2
Total (A\$M)	28.9	10.29
Annual revenue requirement @ 10% (A\$M)	2.75	0.98
Unit tariff A\$/GJ	0.38	0.35

Data source: ACIL Tasman analysis

Table 20 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 20 **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	\$0.38	\$1.09	\$1.37	\$0.35	\$1.09	\$1.44
Brisbane	\$0.38	\$0.57	\$0.95	\$0.35	\$1.08	\$1.43
Mount Isa	\$0.38	\$2.01	\$2.29	\$0.35	\$2.52	\$2.87
Adelaide	\$0.38	\$1.65	\$2.03	\$0.35	\$2.16	\$2.51
Sydney	\$0.38	\$2.08	\$2.46	\$0.35	\$2.59	\$2.94

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

¹⁷ Jemena Physical Description and Operating Information Queensland Gas Pipeline, 18 August 2008 Revision 1.1 accessed at <http://jemena.com.au/assets/what-we-do/assets/queensland-gas-pipeline/Physical%20Description%20and%20Operating%20Information.pdf> on 14 May 2012.

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 are 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 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.

Martin Pavelka, Analyst

Martin Pavelka is a research analyst in ACIL Tasman's Brisbane office. Martin provides economic and quantitative research, analysis and advice to clients predominantly relating to the electricity and commodity markets. Martin has worked extensively on energy industry matters across a broad range of projects

including price forecasting studies; project evaluations, transmission and distribution networks.

Recently Martin has been mainly involved in energy projects in the NEM and the WEM including short term, detailed scenario and long term market outlook modelling. Martin has played a key analytical role in several electricity modelling based his detailed knowledge of ACIL Tasman's energy market models. These models include:

- *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;
- *PowerMark LT* – long term model of the National Electricity Market used for price and market forecasting; and
- *RecMark* – detailed model of the Expanded renewable energy target scheme.

Additionally, Martin has in depth knowledge of local and international commodity markets. Martin also has experience in using microeconomic modelling tools through his involvement in a range of project evaluations particularly in the energy sector.

Martin graduated with a Master of Commerce and Honours in Economics from the University of Queensland.

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 theory¹⁸, 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.

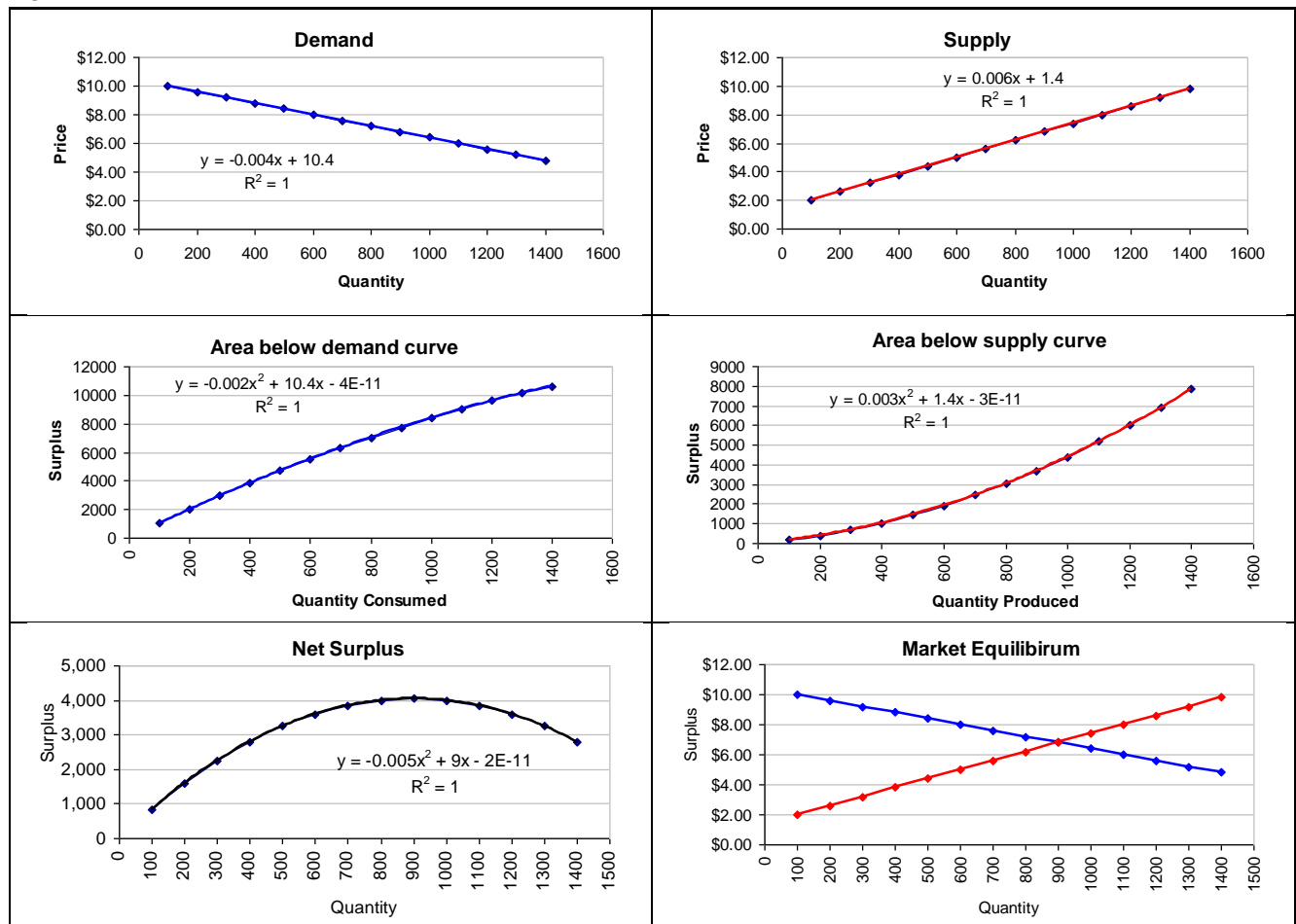
Figure 20 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure 20 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure 20 show the integrals of these demand and supply functions, 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

¹⁸ 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 overlaid 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.



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- **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.