APPENDIX 22

ARROW LNG PLANT

Implications for Domestic Gas Markets

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Confidential

Arrow LNG Plant: implications for domestic gas markets

An assessment of potential impacts of the Arrow LNG Plant project on domestic gas availability and price

Prepared for Arrow CSG (Australia) Pty Ltd and Coffey Environments Australia Pty Ltd

V6 – 22 July 2011

ACIL Tasman

Economics Policy Strategy

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Glossary

Term	Definition
1P Proved (gas reserves)	10% probability of actual reserves being higher than the reserves estimate.
2P Proved and probable (gas reserves)	50% probability of actual reserves being higher than the reserves estimate.
3P Proved, probable and possible (gas reserves)	90% probability of actual reserves being higher than the reserves estimate.
ABARE	Australian Bureau of Agricultural and Resource Economics.
AEMO	Australian Energy Market Operator. Established in 2009, AEMO replaced and assumed the functions of the former National Energy Market Management Company (NEMMCO), Victorian Energy Networks Corporation (VENCorp), Electricity Supply Industry Planning Council (ESIPC), Retail Energy Market Company (REMCO), Gas Market Company (GMC), and Gas Retail Market Operator (GRMO).
bbl	a barrel (of oil), 42 US gallons or approximately 159 litres.
CCGT	combined cycle gas turbine
CO_2	carbon dioxide
Consumer Price Index (CPI)	A price index published regularly by the Australian Bureau of Statistics, calculated as the current cost of a fixed basket of consumer goods, divided by the cost of the basket in the base period.
CSG	coal seam gas, adsorbed in coal seams
DEEDI	Queensland Department of Employment, Economic Development and Innovation
DERM	Queensland Department of Environment and Resource Management
Eastern Australia	For the gas market, Queensland, New South Wales (including Australian Capital Territory), Victoria, South Australia and Tasmania.
GJ	gigajoule (10^9 joules)
GDP	Gross Domestic Product. The total market value of goods and services produced in a country within a given period after deducting the cost of goods and services used in the process of production, but before deducting allowances for the consumption of fixed capital.
GSP	Gross State Product. The total market value of goods and services produced in a State/Territory within a given period after deducting the cost of goods and services used in the process of production, but before deducting allowances for the consumption of fixed capital.
GWh	gigawatt hour (of electrical energy)
IHS/CERA	A US-based oil and gas information supplier.
Liquefaction (gas)	Conversion of hydrocarbon gases (principally CH_4) into liquid form (LNG) by compression and refrigeration.
LNG	liquefied natural gas
LNG train	A single processing unit in an LNG liquefaction plant.
MPa	megapascals, a measure of gas pressure
Mtpa	million tonnes per annum (of LNG)
MW	megawatt (of electrical generating capacity)

NEM	The Eastern Australian (National) electricity market
OCGT	open cycle gas turbine
PJ	petajoule, a unit of energy equal to 10^{15} joules
Reserves	Quantities of gas known to exist, with a defined probability that the actual quantity of economically recoverable gas will be greater than or equal to the specified quantity.
Resources	Quantities of gas inferred to exist, but for which the probability that the specified quantity of gas can be economically recovered is not known.
scf	standard cubic feet
TJ	terajoule, a unit of energy equal to 10^{12} joules
tpa	tonnes per annum

Executive summary

Eastern Australia has historically enjoyed low gas prices by international standards. The development of an export LNG industry based on Coal Seam Gas (CSG) production has the potential to put upward pressure on gas prices, along with other drivers now in play such as rising production costs, carbon pricing and the increased capital cost of transportation infrastructure.

The continued availability of competitively-priced gas is important to achievement of government policy objectives in relation to increased use of gas and reduced carbon dioxide (CO_2) emissions from electricity generation. This report examines the potential impacts of the Arrow LNG Plant project and other committed and proposed liquefied natural gas (LNG) developments in Central Queensland on domestic gas availability and price in the Eastern Australian region[1]. Four scenarios are considered: a Base Case which incorporates all existing and committed gas loads (including the Queensland Curtis LNG Project and the Gladstone GLNG Project) but excludes the Arrow LNG Plant; Project Scenario 1 which adds the Arrow LNG Plant Trains 1 and 2 to the gas loads in the Base Case; Project Scenario 2 including the full capacity for the QCLNG and GLNG projects contemplated under their respective environmental approvals and full development of the Arrow LNG Plant to 16 Mtpa; and a Cumulative Scenario which includes a number of other proposed but not-yet-committed projects including two additional CSG LNG developments at Gladstone (APLNG, Fishermans' Landing LNG). Using an economic model of the Eastern Australian gas market to compare these scenarios, the following conclusions are drawn:

- Coal seam gas (CSG) production at the levels required for large-scale LNG manufacture is likely to be sustainable over the medium to long term without major impacts on domestic gas supply, but the potential impacts increase as the cumulative scale of the LNG industry increases.
- In Queensland (Brisbane City Gate) prices are initially much lower than in the other states because of the influence of ramp-up gas. All scenarios show a sharp rise in Queensland prices from 2015 with the commissioning of the first LNG plants and the availability of ramp-up gas to suppress prices ceases.
- Under the model assumptions about the size of the Queensland CSG resource and production costs, if the Arrow LNG Plant is the only LNG project above baseline (Project Scenarios 1 & 2) it would have a relatively mild effect on Eastern Australian gas consumption and prices. Those effects would be felt mainly in Queensland, where domestic gas consumption would be between 2.5% and 3.7% lower on average each year

[1] In this report the term "Eastern Australia" refers to gas markets in Queensland, New South Wales, Victoria, Tasmania and South Australia.

over the period 2020 to 2030, and wholesale gas prices would be between 8% and 14% higher on average over the same period.

In the unlikely event that the Arrow LNG Plant and all other current CSG-based LNG project proposals were to proceed to full development, along with those projects that have already reached final investment decision (Cumulative Scenario), the modelling indicates potential for very significant impacts on domestic gas availability and pricing in Queensland. In practice, the risk of severe impacts on the Eastern Australian domestic market will be mitigated by normal commercial market mechanisms and disciplines. Investment and funding approvals will require high levels of confidence in the size and deliverability of gas resources to support the LNG developments, and commercial stakeholders including investors, debt providers and customers are likely to require levels of resource redundancy that will provide a buffer for domestic markets. The Queensland Government's current policies relating to gas supply security provide further risk mitigation. However, notwithstanding the low probability attaching to the Cumulative Scenario, we have modelled it in accordance with our project brief so that the full range of potential development scenarios is considered. The modelling shows that:

- Even with an assumed resource base of some 110,000 PJ across a range of price points—approximately four times the proven and probable reserves of CSG in Queensland as at mid 2010—there are very significant impacts on modelled gas consumption and price under the Cumulative Scenario, particularly in the period after 2020. Total gas consumption in Eastern Australia would be some 236 PJ/a lower by 2030, with 213 PJ/a of this reduction occurring in Queensland. Most of the reduction (159 PJ/a in Queensland) would occur in the electricity sector, and to a lesser extent in the industrial and minerals processing sectors. Nevertheless the levels of gas use in electricity generation would continue to exceed the Queensland government's targeted minimum levels of gas use for electricity generation.
- The modelled price effects under the Cumulative Scenario are much stronger than for the Project Scenarios. In Queensland modelled wholesale prices under this scenario increase by an average of $3.78/GJ or 64 % over the period 2020 to 2030. The average prices in the southern states over the same period are much smaller with an increase in New South Wales averaging 3.2%; in Victoria 2.6%; and in South Australia 3.8%.

In practice, the extent of the consumption and price impacts from rapid expansion of LNG production in Eastern Australia will depend on the size and timing of that expansion and on the size of the producible CSG resource that is ultimately established. The modelled effects of the Cumulative Scenario would be less severe if the scale and pace of expansion was slower, or if the resources of CSG and production capability available at a given price level were higher. Conversely, faster expansion of the industry and/or a smaller, higher cost CSG reserve than has been assumed would amplify the modelled consumption and price effects. If LNG development occurs at the scale assumed in the Cumulative Scenario, there will be a need to access CSG resources that are more difficult and expensive to produce. However, each incremental LNG train will need to be commercially viable at the average cost of the gas supply available to it. Hence there is an implicit assumption in the Cumulative Scenario that cost improvements (through scale economies and technology learning effects) will effectively offset the higher costs of accessing marginal CSG resources.

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1 Introduction

Arrow CSG (Australia) Pty Ltd (Arrow Energy) proposes to develop a liquefied natural gas (LNG) facility on Curtis Island off the central Queensland coast near Gladstone. The project, known as the Arrow LNG Plant, is a component of the larger Arrow LNG Project. The proponent is a subsidiary of Arrow Energy Holdings Pty Ltd which is wholly owned by a joint venture between Royal Dutch Shell plc and PetroChina Company Limited.

The Coordinator-General of the State of Queensland (Coordinator-General) has declared the project to be a significant project for which an environmental impact statement (EIS) is required in accordance with Part 4 of the *State Development and Public Works Organisation Act 1971*.

The Australian Government has determined that the project constitutes a controlled action pursuant to the *Environment Protection and Biodiversity Conservation Act 1999*.

The Queensland Coordinator-General issued terms of reference for the EIS in January 2010. The terms of reference set out the requirements, both general and specific, that the proponent is required to address in preparing the EIS.

1.1 The Arrow LNG Plant

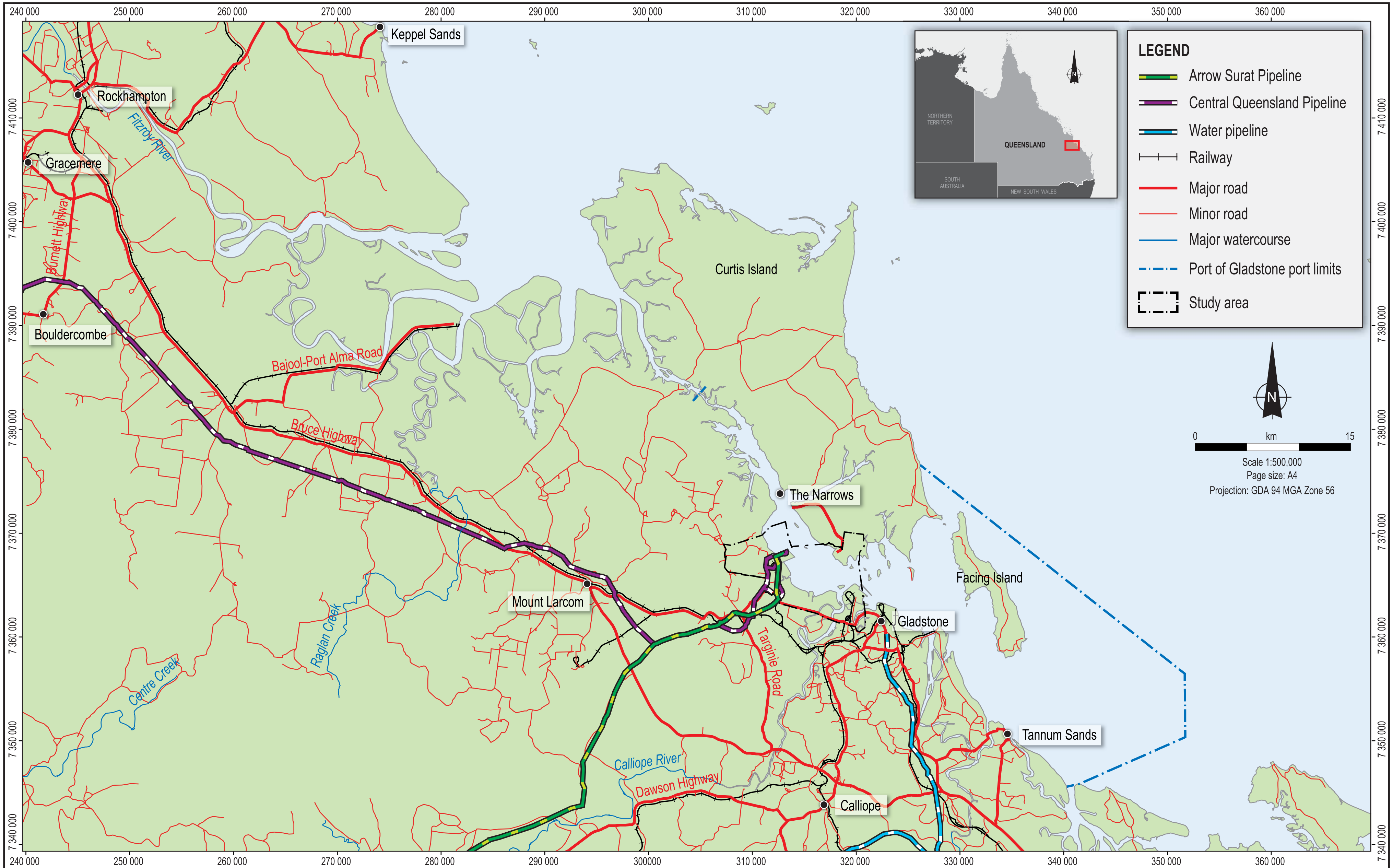
The Arrow LNG Plant will be supplied with coal seam gas from gas fields in the Surat and Bowen basins via high-pressure gas pipelines to Gladstone, from which a feed gas pipeline will provide gas to the LNG plant on Curtis Island. A tunnel is proposed for the feed gas pipeline crossing of Port Curtis.

The upstream CSG production activities and high pressure gas transmission pipeline construction and operation are, for purposes of the EIS, regarded as separate activities and are not directly addressed in this report. However given that the purpose of this report is to assess the potential impacts of the Arrow LNG Plant on domestic gas availability and price in the Eastern Australian region, the production and transportation of CSG to support operation of the Arrow LNG Plant is a necessary and integral part of the analysis.

1.1.1 Project location

Arrow Energy proposes to construct the Arrow LNG Plant in the Curtis Island Industry Precinct at the southwestern end of Curtis Island, approximately 6 km north of Gladstone and 85 km southeast of Rockhampton, off Queensland's central coast. In 2008, approximately 10% of the southern part of the island was added to the Gladstone State Development Area to be administered by the Queensland Department of Local Government and Planning. Of that area, approximately 1,500 ha (25%) has been designated as the Curtis Island Industry Precinct and is set aside for LNG development. The balance of the Gladstone State Development Area on Curtis Island has been allocated to the Curtis Island Environmental Management Precinct, a flora and fauna conservation area.

The regional location of the Arrow LNG plant project is shown in Figure 1.



Source:
Place names, roads, railways, watercourses and pipelines from GEODATA250k (Optimum scale 1:250,000)
Coastline from GBRMPA.
Port of Gladstone port limits digitised by Coffey Environments.

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Arrow Energy

Arrow LNG Plant

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Regional location

Figure No:
1

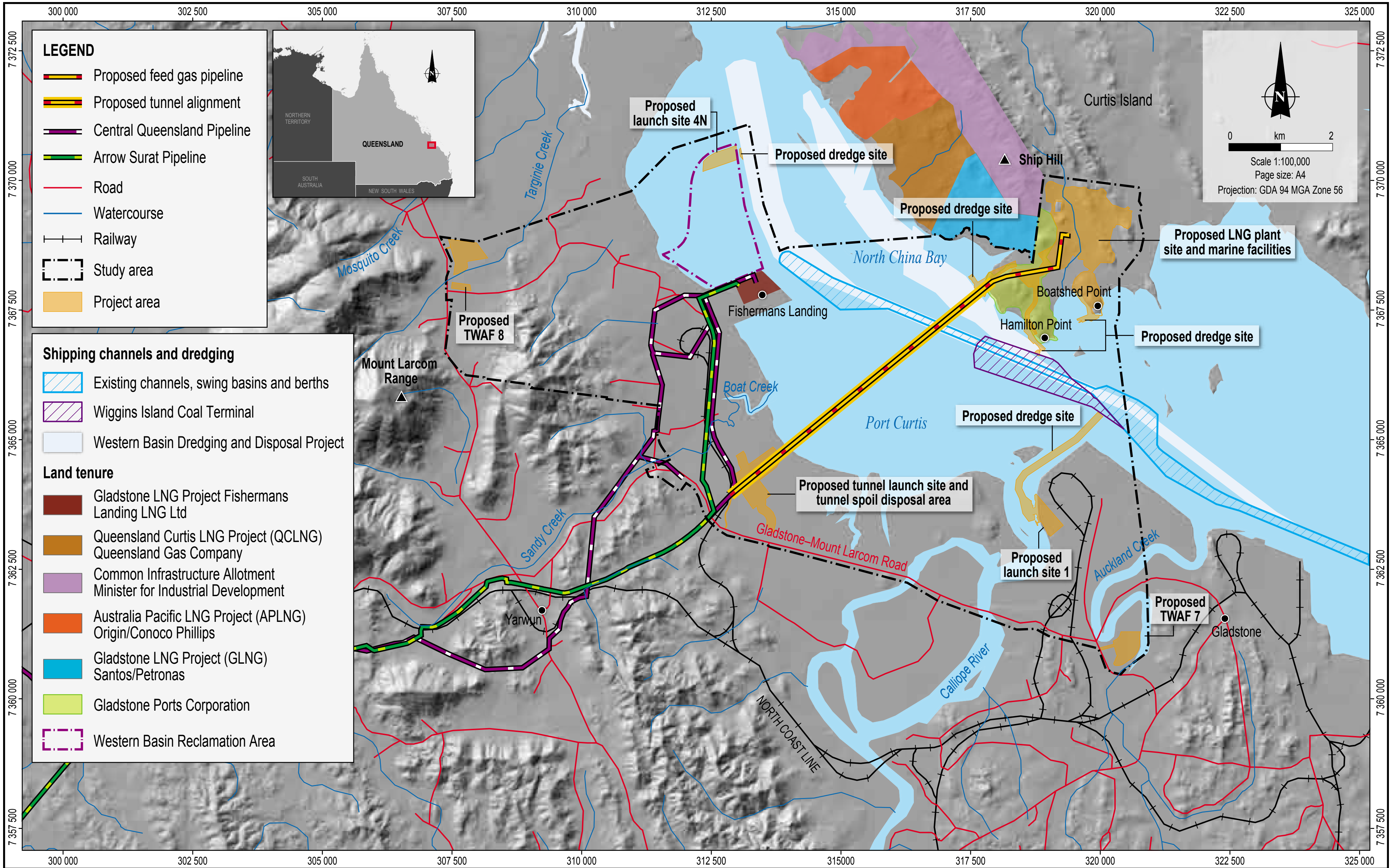
1.1.2 LNG Plant and Associated Infrastructure

The proposed LNG plant as shown on Figure 2 will have a base-case capacity of 16 Mtpa, with a total plant capacity of up to 18 Mtpa. The plant will consist of four LNG trains, each with a nominal capacity of 4 Mtpa. The project will be undertaken in two phases of two trains (nominally 8 Mtpa in each phase), with separate final investment decisions (FIDs) undertaken for each phase.

Operations infrastructure associated with the LNG plant includes the LNG trains (where liquefaction occurs; see 'Liquefaction Process' below), LNG storage tanks, cryogenic pipelines, seawater inlet for desalination and stormwater outlet pipelines, water and wastewater treatment, a 110 m high flare stack, power generators (see 'LNG Plant Power' below), administrative buildings and workshops.

Construction infrastructure associated with the LNG plant includes construction camps, a concrete batching plant and laydown areas.

The plant will also require marine infrastructure for the transport of materials, personnel and product (LNG) during construction and operations.



Source:
Place names, roads and watercourses from DME.
Study area, pipelines, proposed auxiliary facilities and marine infrastructure from Arrow Energy.
Proposed feed gas pipeline, proponents and DEM from Coffey Environments.
Western Basin Dredging Master Plan from Gladstone Ports Corporation.

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LNG Facility

Figure No: 2

Construction Schedule

The plant will be constructed in two phases. Phase 1 will involve the construction of LNG trains 1 and 2, two LNG storage tanks (each with a capacity of between 120,000 m^3 and 180,000 m^3), Curtis Island construction camp and (if additional capacity is required) a mainland workforce accommodation camp. Associated marine infrastructure will also be required as part of Phase 1. Phase 2 will involve the construction of LNG trains 3 and 4 and potentially a third LNG storage tank. Construction of Phase 1 is scheduled to commence in 2014 with train 1 producing the first LNG cargo in 2017. Construction of Phase 2 is anticipated to commence approximately five years after the completion of Phase 1 but will be guided by market conditions and a final investment decision at that time.

LNG Plant Power

Power for the LNG plant and associated site utilities may be supplied from the electricity grid (mains power), gas turbine generators, or a combination of both, leading to four configuration options that will be assessed:

- Base case (mechanical drive): The mechanical drive configuration uses gas turbines to drive the LNG train refrigerant compressors, which is the traditional powering option for LNG facilities. This configuration would use coal seam gas and end flash gas (produced in the liquefaction process) to fuel the gas turbines that drive the LNG refrigerant compressors and the gas turbine generators that supply electricity to power the site utilities. Construction power for this option would be provided by diesel generators.
- Option 1 (mechanical/electrical – construction and site utilities only): This configuration uses gas turbines to drive the refrigerant compressors in the LNG trains. During construction, mains power would provide power to the site via a cable (30-MW capacity) from the mainland. The proposed capacity of the cable is equivalent to the output of one gas turbine generator. The mains power cable would be retained to power the site utilities during operations, resulting in one less gas turbine generator being required than the proposed base case.
- Option 2 (mechanical/electrical): This configuration uses gas turbines to drive the refrigerant compressors in the LNG trains and mains power to power site utilities. Under this option, construction power would be supplied by mains power or diesel generators.
- Option 3 (all electrical): Under this configuration mains power would be used to supply electricity for operation of the LNG train refrigerant compressors and the site utilities. A switchyard would be required. High-speed electric motors would be used to drive the LNG train refrigerant compressors. Construction power would be supplied by mains power or diesel generators.

For purposes of calculating the auxiliary gas requirements for provision of LNG plant power, the analysis in this report assumes the base case (mechanical drive) configuration.

Liquefaction Process

The coal seam gas enters the LNG plant where it is metered and split into two pipe headers which feed the two LNG trains. With the expansion to four trains the gas will be split into four LNG trains.

For each LNG train, the coal seam gas is first treated in the acid gas removal unit where the carbon dioxide and any other acid gases are removed. The gas is then routed to the dehydration unit where any water is removed and then passed through a mercury guard bed to remove mercury. The coal seam gas is then ready for further cooling and liquefaction.

A propane, precooled, mixed refrigerant process will be used by each LNG train to liquefy the predominantly methane coal seam gas. The liquefaction process begins with the propane cycle. The propane cycle involves three pressure stages of chilling to pre-cool the coal seam gas to –33°C and to compress and condense the mixed refrigerant, which is a mixture of nitrogen, methane, ethylene and propane. The condensed mixed refrigerant and pre-cooled coal seam gas are then separately routed to the main cryogenic heat exchanger, where the coal seam gas is further cooled and liquefied by the mixed refrigerant. Expansion of the mixed refrigerant gases within the heat exchanger removes heat from the coal seam gas. This process cools the coal seam gas from –33°C to approximately –157°C. At this temperature the coal seam gas is liquefied (LNG) and becomes 1/600th of its original volume. The expanded mixed refrigerant is continually cycled to the propane precooler and reused.

LNG is then routed from the end flash gas system to a nitrogen stripper column which is used to separate nitrogen from the methane, reducing the nitrogen content of the LNG to less than 1 mole per cent (mol%). LNG separated in the nitrogen stripper column is pumped for storage on site in full containment storage tanks where it is maintained at a temperature of –163°C.

A small amount of off-gas is generated from the LNG during the process. This regasified coal seam gas is routed to an end flash gas compressor where it is prepared for use as fuel gas.

Finally, the LNG is transferred from the storage tanks onto LNG carriers via cryogenic pipelines and loading arms for transportation to export markets. The LNG will be regasified back into sales specification gas on shore at its destination location.

Marine Infrastructure

Marine facilities include the LNG jetty, materials offloading facility (MOF), personnel jetty and mainland launch site.

Feed Gas Pipeline

An approximately 8-km long feed gas pipeline will supply gas to the LNG plant from its connection to the Arrow Surat Pipeline (formerly the Surat Gladstone Pipeline) on the mainland adjacent to Rio Tinto's Yarwun alumina refinery. The feed gas pipeline will be constructed in three sections:

- A short length of feed gas pipeline will run from the proposed Arrow Surat Pipeline to the tunnel launch shaft, which will be located on a mudflat south of Fishermans Landing, just south of Boat Creek. This section of pipeline will be constructed using conventional open-cut trenching methods within a 40-m wide construction right of way.
- The next section of the feed gas pipeline will traverse Port Curtis harbour in a tunnel to be bored under the harbour from the launch shaft to a receival shaft on Hamilton Point. The tunnel under Port Curtis will have an excavated diameter of up to approximately 6 m and will be constructed by a tunnel boring machine that will begin work at the mainland launch shaft. Tunnel spoil material will be processed through a de-sanding plant to remove the bentonite and water and will comprise mainly a finely graded fill material, which will be deposited in a spoil placement area established within bund walls constructed adjacent to the launch shaft. Based on the excavated diameter, approximately 223,000 m^3 of spoil will be treated as required for acid sulfate soil and disposed of at this location.
- From the tunnel receival shaft on Hamilton Point, the remaining section of the feed gas pipeline will run underground to the LNG plant, parallel to the above ground cryogenic pipelines. This section will be constructed using conventional open-cut trenching methods within a 30-m wide construction right of way.

1.2 Scope of this report

The work has been commissioned by Coffey Environments Australia Pty Ltd, on behalf of Arrow CSG (Australia) Pty Ltd, as one of a suite of technical studies which provide input to the EIS. ACIL Tasman has agreed to the publication of this report as a supporting study for EIS.

The requirements in relation to assessment of potential economic impacts of the project are set out in Section 5 of the terms of reference. This report addresses the following specific aspect of the requirements in Section 5:

> 'The general economic benefits/ impacts from the project should be described, including:

> ...
>
> The potential impact of the project on the domestic gas market and domestic gas prices, including the ability of the power generation sector to meet government emission targets and gas-power level targets.' [Terms of Reference p.83]

To address this component of the terms of reference, the report provides an analysis of the potential impacts of the project on the availability and price of gas for use in domestic markets, including gas for power generation required to meet relevant government policy targets (Queensland 18% gas scheme[2]; national carbon pricing arrangements).

The other matters required to be addressed under Section 5 of the terms of reference are the subject of a separate report to be prepared by AEC Group.

1.3 Background to the study scope

Establishment of a large scale LNG industry based on coal seam gas (CSG) from the Bowen and Surat Basins in Central and Southern Queensland is now proceeding, with four LNG trains (total capacity 16.3 million tonnes per year) having been committed by early 2011. Further development commitments are anticipated in the near term[3]. We consider it unlikely that all of the LNG projects proposed to be developed in the Gladstone region will proceed to the full scale covered by their respective IAS/EIS statements, but if this were to happen the Queensland CSG LNG industry could ultimately see in excess of 60 million tonnes of LNG processed and exported from Gladstone each year. To put that prospect in context, 60 million tonnes of LNG product per year is equivalent to about 3,300 PJ/a of gas. Allowing for additional gas used in production, transportation and processing, gross CSG production required to support this level of LNG development is likely to be around 3,780 PJ/a. This compares to a current eastern Australian domestic gas market of about 730 PJ/a.

Production of CSG for manufacture of LNG on this scale raises a number of important questions relating to the extent to which establishment of an LNG export industry based on CSG in Central Queensland might affect availability of supply for the local market and affect domestic gas prices. For example, will the establishment of LNG exports deprive the domestic market of gas? Will exposure of the local market to international prices see domestic prices move up to "full import parity"? In this report we seek to address these questions by

[2] The Queensland Gas Scheme currently prescribes parties to source 13% of electricity from gas. This target rises to 15% in 2010 with an option to increase it to 18% in 2020.

[3] For example, in April 2011 the Origin Energy/ConocoPhillips consortium APLNG announced a binding LNG sales agreement with Sinopec for supply of 4.3 Mtpa of LNG for 20 years (APLNG, 2011). As a result, it is anticipated that APLNG will make a Final Investment Decision on either one or two LNG trains in the near future.

comparing results of four scenarios using ACIL Tasman's proprietary model of the Eastern Australian gas market, known as *GasMark Global (GMG) Australia*[4]. The scenarios considered are described in the Methodology section of this report (section 2):

Large scale development of export LNG projects in Central Queensland will rely on a high level of success in demonstrating the scalability of CSG resources and production, and will only come about if technological developments allow large areas of gas-bearing coal measures to be brought into commercial production. Gas that is currently being earmarked for LNG projects will only be committed and used for LNG when there are sufficient quantities to allow the large scale investment to proceed. If there is insufficient gas available there will be no LNG projects.

Large scale development of LNG presupposes demonstration of strong performance of the CSG resource base in terms of reliability, competitiveness and scalability of CSG production. This will be reflected in a larger economically recoverable CSG resource with an associated supply cost curve under which large quantities of economically producible gas will be available. ACIL Tasman has estimated that the economically recoverable CSG required to support the Cumulative Scenario would need to be at least 110,000 PJ.

Nevertheless it must be expected that production of the Eastern Australian CSG resource will follow a normal discovery and depletion pathway that will see (on average) large, easily accessible and lower cost resources produced first and smaller, less accessible and higher cost resources produced later. In other words, we must expect that production will move generally along a "supply cost curve" that will see costs of production (and therefore the minimum prices required to justify investment in new productive capacity) increasing over time.

1.4 Eastern Australian gas pricing trends

Historically most of the gas in Eastern Australia, and in particular in Queensland, has been bought and sold on the basis of long-term bilateral contracts, typically for terms of ten to twenty years. Transportation contracts have been structured to match these long term sales contracts and have similar durations. There has been a trend in recent years toward shorter term supply, but most gas supply and transportation contracts still run for at least five years. Foundation contracts underpinning new facilities development (production projects and major gas-consuming plant) are still often settled for terms of up to 20 years. Indeed, it is commonly argued that such long-term contracts are essential to the financing of new projects because they provide reasonable

[4] An explanation of how the *GMG Australia* model works is provided in Appendix A.

security of long term gas supply as well as a degree of cost and revenue stability.

Periodic price review mechanisms, which provide some protection to both buyers and sellers against prices moving and remaining seriously "out of market", are a feature of most long-term gas supply contracts. Between reviews, prices are typically defined according to a base price that is indexed regularly, most often to the Consumer Price Index (CPI). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. However the many variations in detailed commercial provisions such as term, volume, volume flexibility (minimum bill or "take-or-pay" levels; banking rights; relationships between annual contract quantities and maximum daily quantities); penalties associated with failure to supply, and so forth mean that there can be very significant price differences between contracts. Hence the idea of a single market clearing price has little relevance in the current Eastern Australian market. However, it is possible that as gas infrastructure develops and greater price transparency emerges as more formal short-term trading markets are established, prices for spot purchase of gas under standardised service terms will converge.

Gas prices in Eastern Australia have historically been low by international standards and the prevalence of long term contracts has ensured price stability. In Australia natural gas has generally been seen as a substitute for coal and coal-based electricity, rather than for oil or other petroleum products. Australia's abundant, low-cost coal resources and the absence of a route to export have effectively capped gas prices, limiting the prices that large-scale users in power generation and industrial applications have been willing and able to pay. In this regard—and despite the introduction of short-term trading markets in New South Wales and South Australia during 2010 and in Queensland from late 2011—the Eastern Australian market is quite different from the markets in many overseas countries, including the USA, UK, Europe and a number of Asian countries where gas prices closely follow oil prices.

1.4.1 The role of costs in setting gas prices

Production costs influence but do not determine the price of gas in the Eastern Australian market. In the past, local gas prices have been set by reference to the price of substitute energy (in particular coal) rather than by cost of production. In other words, gas has not historically been priced on a cost-plus basis that merely provides an economically efficient return over costs of production. It has been priced on the basis of "what the market will bear" taking into consideration competitive alternatives. Cost of production will, however, set a lower bound on future gas prices in the sense that producers will not invest in new productive capacity if the prices that are sustainable in the market fail to cover long run cost of establishing and operating that capacity, including a risk-reflective commercial rate of return to the producer.

1.4.2 Recent gas pricing trends

Through the early 2000s, wholesale domestic gas prices throughout Eastern Australia remained low. In Southern Australia prices generally moved in line with inflation; in Queensland where the CSG industry was emerging and new producers were keen to establish market share, new supply contracts saw significant price discounting.

During 2007 and early 2008, the outlook for prices changed significantly as a result of a number of converging factors:

- There was sustained upward pressure on exploration and development costs. This trend was not confined to Australia, but was observed around the world as a result of strong global demand and capacity constraints. It was particularly evident in offshore oil and gas developments where upstream development cost indicators more than doubled between 2005 and mid 2008 (IHS/CERA, 2010).[5]
- Proponents of LNG plants in Queensland began to focus attention on establishing reserves and production capability to underpin their proposed developments. As a result, while these producers were (and remain) willing to sell gas on a spot or short term basis, they became less willing during the reserves-build process to enter into long-term, large volume supply contracts.
- Drought conditions in Eastern Australia during 2007 saw electricity prices rise sharply—and gas prices followed. While both electricity and spot gas prices have retreated with the easing of drought conditions and relaxation of other electricity generation constraints, the demonstrated ability of the market to absorb higher gas prices may continue to influence near-term price settlements.
- The anticipated introduction of a national emission trading scheme meant that gas was seen as a more valuable commodity. Both producers and consumers began to factor in higher anticipated gas demand and greater intrinsic value into the pricing of long-term contracts that bridged across the anticipated introduction of emission trading.
- Finally, domestic coal prices came under sustained upward pressure as a result of strongly rising mining costs, as well as renegotiation of contracts for supply to Queensland and New South Wales generators at a time when international coal prices were very high and the range of coal qualities being traded internationally was much wider than in the past.

[5] Cambridge Energy Research Associates, Upstream Capital Costs Index, October 2010.

The net result of these influences was that domestic gas prices rose significantly through 2007 and the first half of 2008.

Since mid 2008 a number of further developments have affected gas prices. In the Victorian spot market there has been a significant softening of prices, apparently driven by the introduction of a large amount of new supply from the Otway and BassGas projects during 2008. More generally, the effects of the global financial crisis and the collapse in world oil prices from mid-2008 (now recovering strongly), together with the rapid emergence of shale gas production in the United States of America, appear to have tempered the upward pressure on capital costs and gas prices for the time being. Delays in introduction of a carbon pricing scheme—now proposed to commence mid-2012—mean that the value uplift for gas as a result of explicit carbon pricing has not yet occurred, although both producers and consumers continue to factor in expectations of higher gas demand and greater intrinsic value into the pricing of long-term gas supply contracts.

1.4.3 Linkage between international gas prices and the Eastern Australian Gas Market

High oil prices—which in July 2008 climbed above US$140/bbl—flowed on to international gas prices. This accentuated the gap between international prices and Australian domestic prices. After falling sharply from mid-2008 to less than US$40/bbl by January 2009, oil prices have risen as global economies recover and by February 2011 had once again risen above US$100/bbl. Given the pricing relativities between oil and LNG, international gas prices can be expected to follow that general trend. The question is to what extent domestic gas prices in Eastern Australia will be influenced by those trends if a substantial LNG export industry is established in Gladstone.

To the extent that gas producers in Eastern Australia have the capacity to switch supply between local and international markets, it would be reasonable to expect a significant degree of price convergence. However that switching capacity is, in our view, likely to be limited because the option of directing gas production into LNG manufacture is not open to all producers. Selling LNG into the international market *may* yield higher netback value for gas, but there are significant barriers to entry for LNG participants. First, there is the need to aggregate very large gas reserves to support a project, with high levels of confidence in the size and producibility of the reserves needed to secure project financing and LNG sales contracts. Financial capacity is also important: the proponents must be able to fund the multi-billion dollar capital requirements to develop the upstream production facilities, even if the LNG facility can be project financed. There is also a very different risk profile compared with domestic gas sales where prices under long-term bilateral contracts usually follow a very predictable path. The plunge in oil prices between mid 2008 and early 2009 amply demonstrated that LNG prices linked to oil will display much greater volatility and risk than traditional CPI-linked gas prices in the Australian domestic market.

The CSG reserves and production capacity required to supply feed gas for LNG production are likely to be dedicated solely to LNG production. The financing of such projects will usually involve commercial covenants preventing diversion of project gas reserves into domestic markets.

On the other hand, reserves and production capacity that remains outside the committed requirements of committed and future LNG plants, whether held by the same LNG developers or by other producers, will not generally have the option of diversion into LNG manufacture once reserves for the LNG trains are satisfied.

The gas reserves dedicated to LNG can be viewed as "ring-fenced" from the domestic market. In so far as removing this tranche of gas from the domestic market raises the average cost of production for gas outside these ring-fenced reserves, this move to a higher cost base will set a lower bound on future gas prices. Offsetting this upward pressure on domestic prices to some extent, the existence of a much larger gas system created by the CSG industry will lower overall costs of production and delivery (through ongoing technology developments, a deeper contractor market, and a far more extensive transmission pipeline network).

Producers will not invest in new productive capacity if the prices that are sustainable in the market fail to cover long run costs of establishing and operating that capacity. Those costs need to include a risk-reflective commercial rate of return to the producer. Future gas prices in Eastern Australia will therefore be determined having regard to both the costs of production and the competitive alternatives available to consumers (principally by the carbon-inclusive price of coal) rather than by the price of gas in international markets.

For these reasons we do not expect to see a sustained move to "export parity" pricing of gas in domestic gas markets in Eastern Australia. However other drivers now in play such as rising production costs, carbon pricing and the increased capital cost of transportation infrastructure are likely to see gas prices rising in real terms, with no current prospect of a reversion to former levels.

At present, most of the identified CSG reserves in Queensland are controlled by parties associated with the proposed LNG developments and these parties are currently focussed on establishing the reserves necessary to supply these plants, rather than supplying CSG for long-term domestic contracts. The critical question is whether the major CSG producers will be willing and able to expand production at the margin in order to offer supply to the domestic market once the requirements of the LNG projects have been catered for. This will depend on the price that the domestic market is willing to pay for gas compared to the price that can be obtained for LNG in the international market, taking into account differences in cost structure, price risk and timing of sales.

Perhaps the greatest risk to domestic gas supply will materialise if the gas reserves dedicated to LNG production prove to be less productive than expected. The probability of this situation arising is relatively low: the LNG proponents, their financiers and customers will only make the very large commitments involved in building these projects after thorough due diligence on all aspects of the projects, with the adequacy and reliability of the CSG reserves base a key consideration. However, if despite this close scrutiny prior to FID it turns out that average well performance fails to meet expectations, these projects may have to look to alternative sources of gas in order to maintain LNG production rates. In such circumstances, it might be expected that gas prices will rise rapidly and that buyers in the domestic market will find gas in short supply.

2 Methodology

In seeking to assess the potential impacts of large-scale LNG development in Central Queensland on the availability and price of gas for use in domestic markets, including gas for power generation required to meet government policy targets (Queensland 18% gas scheme; national carbon pricing scheme) this report addresses the following questions:

- Is production of CSG at the levels required for large-scale LNG manufacture sustainable over the medium to long term without major impacts on domestic gas supply?
- Would LNG production on such a scale cause a shortage of gas in the Queensland and broader eastern Australian domestic market, so that expected gas requirements for power generation, industrial, commercial and residential requirements cannot be met?
- Would large scale LNG production push domestic gas prices up to levels that would be unaffordable for some or all domestic market sectors?

In order to address these questions, we have examined four future scenarios:

- A **Base Case** in which the only LNG developments in the region are those that had reached Final Investment Decision by end January 2011, namely the QCLNG Project (BG Group) and the GLNG Project (Santos, Petronas, Total). These projects are assumed to be developed up to the volumes currently committed as part of their final investment decisions: 8.5

Mtpa for the QCLNG Project and 7.8 Mtpa for the GLNG Project. The only new gas load in the Gladstone region included under the Base Case is the stage 2 expansion of the Yarwun alumina refinery, which is scheduled to be commissioned during 2011.

- **Project Scenario 1** in which all developments under the Base Case proceed, together with the first stage of the Arrow LNG Plant up to a capacity of 8 Mtpa (2 trains each of 4 Mtpa).
- **Project Scenario 2** including the full capacity for the QCLNG and GLNG projects contemplated under their respective environmental approvals together with full development of the Arrow LNG Plant to 16 Mtpa (4 trains each of 4 Mtpa).
- **Cumulative Scenario** in which the Arrow LNG Project proceeds along with the currently committed LNG projects and other LNG projects and industrial gas-consuming projects that have been approved by the Queensland Coordinator-General or have sufficient information in the public domain (that is, a completed EIS) to enable an assessment of the potential impacts.

The four scenarios have examined using ACIL Tasman's proprietary eastern Australian gas market model called *GMG Australia*. Further information on the model is provided in Appendix A.

2.1 Modelling assumptions

2.1.1 Base Case

For the purposes of this analysis, the Base Case incorporates a level of LNG development in the Gladstone region consistent with the volumes currently committed for those projects that have recently reached final investment decision to proceed. Key assumptions for the Base Case include:

- QCLNG Project (QGC, CNOOC, Tokyo Gas)[6] proceeds at the scale announced in the 31 October 2010 Final Investment Decision[7], with two LNG trains each of 4.25 Mtpa capacity, for a total of 8.5 Mtpa. These two trains are assumed to come on line in mid 2014 and 2015 respectively.
- GLNG Project (Santos, Petronas, Total and KOGAS) proceeds, with two LNG trains for a total of 7.8 Mtpa. These two trains are each assumed to be of 3.9 Mtpa capacity and to come on line in 2015 and 2016 respectively, in accordance with the configuration announced by the proponents as the basis for their final investment decision[8].

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[6] QGC is a wholly-owned subsidiary of the BG Group.

[7] BG Group media release "BG Group sanctions Queensland Curtis LNG project" dated 31 October 2011.

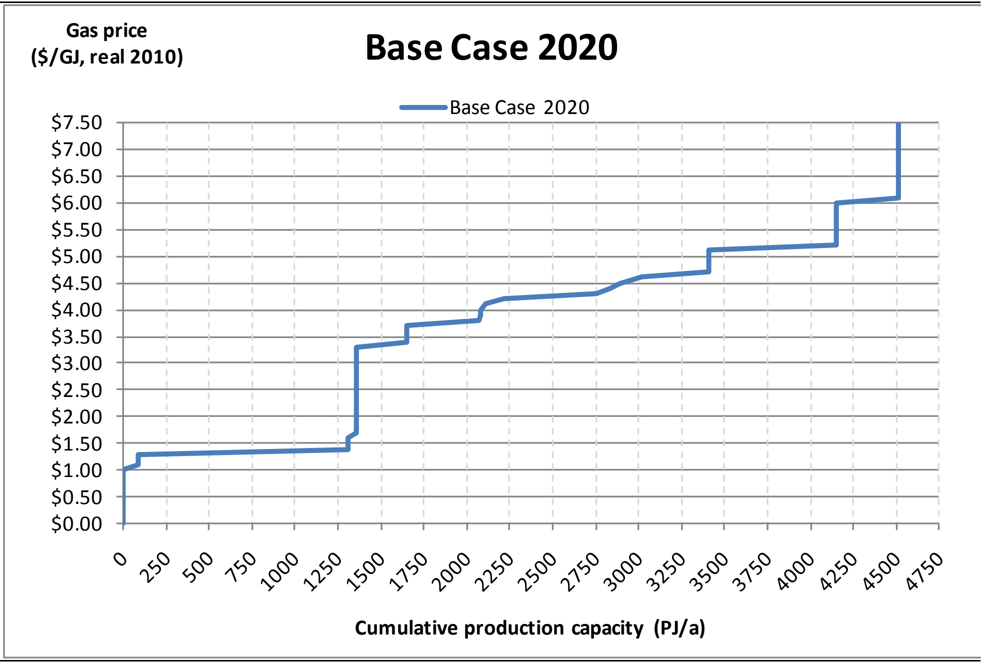
[8] Santos ASX/media release "GLNG Project Sanctioned", dated 13 January 2011.

- The Stage 2 expansion of the Yarwun alumina plant is assumed to increase alumina production capacity at the facility from 2 Mtpa to 3.4 Mtpa by 2011. As a result, natural gas demand at the Yarwun facility is assumed to increase by 7.2 PJ/a.

Gas demand outside the Gladstone region is assumed at levels consistent with ACIL Tasman's current base case gas demand outlook for the Eastern Australian market, including gas demand for electricity generations at levels consistent with introduction of carbon pricing equivalent to the previous Carbon Pollution Reduction Scheme (CPRS) minus 5% scheme, from mid 2013 (Australian Government, 2008). CSG supply capability in Queensland is assumed at overall levels sufficient to support expansion of LNG production up to the full extent of the Cumulative Scenario, but with lower levels of LNG production the actual call on these reserves is greatly reduced, with only those resources in the lower parts of the cost curve brought into production. This reflects an assumption that the underlying CSG supply capability at any point in time is determined by geological fundamentals and by the then-current state of drilling and production technology. While actual levels of CSG production will depend critically on the scale of LNG developments, the presumption in this analysis is that the underlying resource endowment does not change as a result of the scale of development. Rather, increasing levels of LNG production drive the CSG feed requirements further up the cost curve, thereby impacting on the availability and price of gas for the domestic market.

With regard to CSG in Queensland, we assume continued expansion of production capacity and the corresponding reserves base, with costs increasing over time as more expensive, less productive deposits are accessed. Total production capability from Queensland CSG reaches around 4,500 PJ/a, across a range of price points, over the next 10 years. Assuming production over a period of 25 years, this implies a total recoverable resource in place of about 110,000 PJ. This results in an assumed Queensland CSG production cost curve as shown in Figure 3. Note that these costs are expressed on an ex-field basis and do not include costs of transmission.

Figure 3 **Assumed Queensland CSG production cost curve in year 2020**



Data source: ACIL Tasman analysis

  - In the absence of LNG developments much of this productive capability would not be deployed. Ramp up of CSG production prior to LNG commissioning results in excess low cost CSG being available to the market.
- We assume that exploration for CSG in New South Wales succeeds in establishing substantial production capacity in the Sydney, Gunnedah, Gloucester and Clarence-Moreton Basins. Production costs increase over time as more expensive, less productive deposits are accessed. Total production capability from New South Wales CSG reaches around 400 PJ/a across a range of price points over the next 20 years.
- On the demand side the following is assumed:
  - Retail (commercial and residential) demand growth driven by demographic and economic (Gross State Product, GSP) trends, moderated by the impact of energy efficiency initiatives.
  - Industrial growth driven by economic (GSP) trends in the small industrial sector; large industrial based on individual existing and new projects included in data base.
- Gas demand for power generation reflects commencement of an explicit carbon pricing arrangement in mid 2013 and the consequential demand for gas in power generation. The carbon price assumptions adopted are consistent with Treasury modelling of the “CPRS minus 5%” case (Australian Government, 2008) by 2020.
- The model includes a comprehensive representation of existing and committed transmission pipeline capacity as well assumed capacity expansions to meet anticipated market growth. Tariff assumptions for

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

  - Transmission pipeline expansions occur when justified by market opportunities.
  - Tariffs for expansions reflect roll-over of current regulated or commercial tariff arrangements.

- Existing gas supply contracts have not been imposed on the model. As a result the model reveals "economically efficient" gas allocations which may not fully reflect existing commercial arrangements.

2.1.2 Project Scenario 1

The modelling assumptions for Project Scenario 1 are the same as for the Base Case, with the following exceptions:

- **Project Scenario 1** assumes that the Arrow LNG Plant proceeds to develop two LNG trains, each with nominal capacity of 4 Mtpa giving a total production capacity of 8 Mtpa. Train 1 commences commercial production in mid-2017, and Train 2 nine months later. Auxiliary gas requirements (for in-field processing and compression, mid-line compression, and LNG plant use (mechanical drive compression and gas-fired power generation) totals 55 PJ/a for the two-train development.

2.1.3 Project Scenario 2

The modelling assumptions for Project Scenario 2 are the same as for the Base Case, with the following exceptions:

- **Project Scenario 2** assumes that the Arrow LNG Plant proceeds to develop four LNG trains, each with nominal capacity of 4 Mtpa giving a total production capacity of 16 Mtpa. Scheduling of Trains 1 and 2 is as per Project Scenario 1. Train 3 commences commercial production in late 2024, and Train 4 nine months later. Auxiliary gas requirements (for in-field processing and compression, mid-line compression, and LNG plant use (mechanical drive compression and gas-fired power generation) reach a maximum of 110 PJ/a for the four-train development.

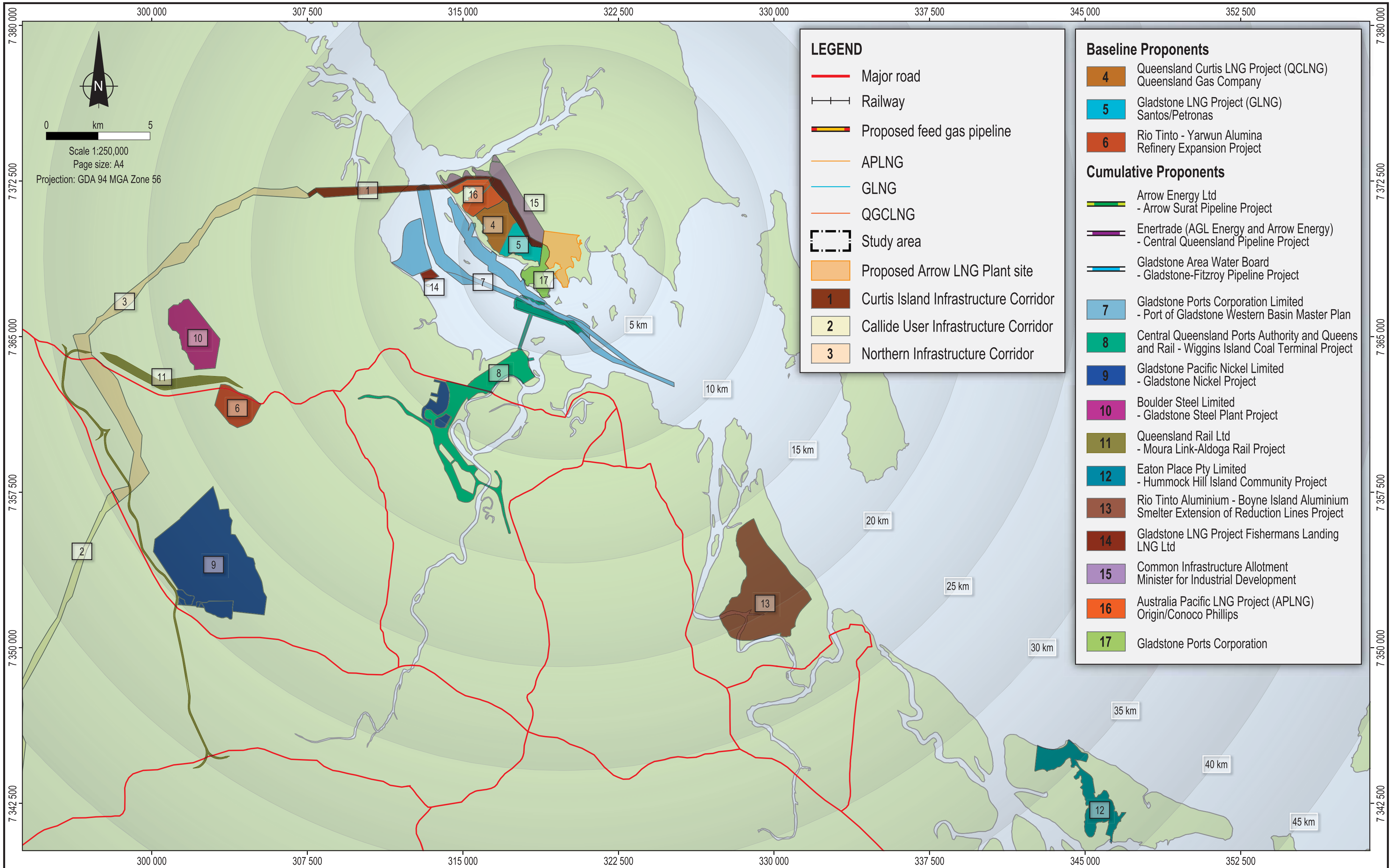
2.1.4 Cumulative Scenario

The Cumulative Scenario represents an extreme case under which all of the current LNG proposals in the Gladstone area proceed to full development at the maximum scale envisaged under the relevant EIS/IAS studies, together with other projects in the Gladstone area that have been approved by the

Queensland Coordinator-General or have sufficient information in the public domain to enable an assessment of the potential impacts. In addition to the gas loads included in Project Scenario 2, the Cumulative Scenario takes into consideration the following projects:

- Australia Pacific LNG Project (APLNG).
- Western Basin Strategic Dredging and Disposal Project.
- Fisherman's Landing Northern Expansion Project.
- Arrow Surat Pipeline Project.
- Central Queensland Pipeline Project.
- Wiggins Island Coal Terminal Project.
- Gladstone Pacific Nickel Project.
- Gladstone Steel Plant Project (Boulder Steel).
- Moura Link – Aldoga Rail Project.
- Gladstone Fitzroy Water Pipeline Project.
- Hummock Hill Island Community Project.
- Boyne Island Smelter Expansion of Reduction Lines (from 545,000 tpa to 733,000 tpa).
- Gladstone LNG Fisherman's Landing Project.

The locations of these projects are illustrated in Figure 4.



Source:
Place names, roads and railways from DME. Coastline from GBRMPA.
Cumulative impact areas interpreted by Coffey Environments.
Study area, pipelines, proposed auxiliary facilities and marine infrastructure from Arrow Energy.
Proposed tunnel alignment from Coffey Environments. Western Basin Dredging and Disposal Project from Arrow Energy.
NOTE: For proponents source information please refer to report reference notes.

coffey environments

Date: 19.07.2011
MXD: 7033CA_07_GIS050_v1_1
File Name: 7033CA_DGS_F004_GIS_GL

Arrow Energy
Arrow LNG Plant

arrow energy go further

Cumulative projects

Figure No: 4

Of these projects, only those involving incremental gas consumption are relevant to the cumulative impacts on the domestic gas market. The following projects involve gas consumption:

- APLNG Project.
- Arrow Surat Pipeline Project.
- Arrow Bowen Pipeline Project.
- Gladstone Pacific Nickel Project.
- Boyne Island Smelter Expansion of Reduction Lines (from 545,000 tpa to 733,000 tpa).
- Gladstone LNG Fisherman's Landing Project.

Gas consumption associated with compression on the Arrow Surat Pipeline and the Arrow Bowen Pipeline is already accounted for in the auxiliary gas requirements for the LNG projects. Hence the only projects not already included in Project Scenario that are relevant to the analysis of cumulative impact on the domestic gas market are the two LNG projects (APLNG and Gladstone LNG Fisherman's Landing), the Gladstone Pacific Nickel Project and the Boyne Island Smelter Expansion. The following assumptions relating to these projects have been incorporated into the analysis of cumulative impacts on the domestic gas market:

- APLNG Project—four trains each of 4.5 Mtpa for a total production capacity of 18 Mtpa, coming into production between mid 2015 and 2022. Auxiliary gas requirements (for in-field processing and compression, mid-line compression, and LNG plant use (mechanical drive compression and gas-fired power generation) totals 148 PJ/a for the four-train development.
- Gladstone LNG Fishermans Landing LNG facility—two trains each of 1.6 Mtpa[9] for a total production capacity of 3.2 Mtpa, coming into production between mid 2015 and 2022 (DERM, 2009). Auxiliary gas requirements (for in-field processing and compression, mid-line compression, and LNG plant use (mechanical drive compression and gas-fired power generation) totals 26 PJ/a for the two-train development.
- Gladstone Pacific Nickel—4 PJ/a gas demand from 2015
- Boyne Island Smelter Expansion—0.5 PJ/a gas demand from 2016.

The Cumulative Scenario has a low probability of eventuating in practice. This is because the implied level of CSG LNG development would be very unlikely to occur unless the extent of low-cost CSG resources is proven to be considerably greater than we have assumed in this study. Nevertheless, we have modelled the Cumulative Scenario in accordance with our project brief so that the full range of potential development scenarios is considered.

[9] The assumed train size is consistent with the design described in the Department of Environment and Resource Management (DERM) Assessment Report dated 14 April 2009.

3 Modelling results

This section summarises the results of each of the modelling scenarios.

First, we show the results for gas consumption for the Eastern Australian market as a whole, and for Queensland, under the different scenarios. This provides a measure of the extent to which LNG exports may constrain availability of gas to meet domestic demand.

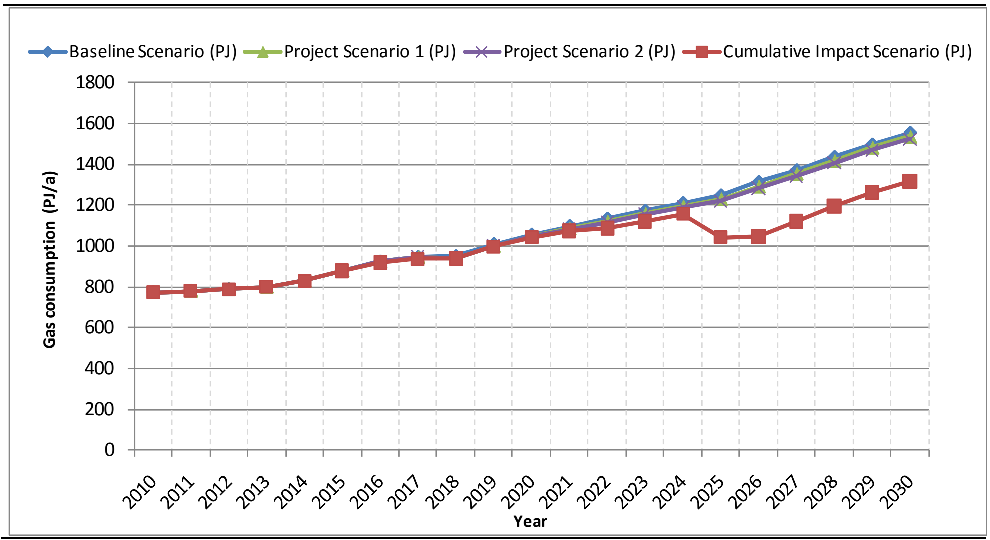
We then look at the levels of consumption of gas for power generation in Queensland. Focusing on the Queensland market is appropriate because, as might be expected, the results show that the effects of the LNG projects in terms of competition for gas supply and price impacts are most strongly felt closest to the LNG plants, in Queensland.

Finally, we examine the modelled prices for gas in the Eastern Australian markets, to assess the extent to which LNG production impacts wholesale prices in the domestic market.

3.1 Gas consumption

Modelled total consumption of gas in Eastern Australia under the four scenarios is illustrated in Figure 5 and Table 1.

Figure 5 **Comparison of Eastern Australian gas consumption from 2010 to 2030 under the Base Case, Project 1, Project 2 and Cumulative Scenarios**



Data source: ACIL Tasman GMG Australia gas market modelling

Table 1 **Eastern Australian gas consumption – differential between scenarios**

	Baseline Scenario (PJ)	Project Scenario 1 (PJ)	Project Scenario 2 (PJ)	Cumulative Impact Scenario (PJ)	Differential Baseline to Project 1 (PJ)	Differential Baseline to Project 2 (PJ)	Differential Baseline to Cumulative (PJ)	%diff Baseline to Project 1	%diff Baseline to Project 2	%diff Baseline to Cumulative
2010	773	773	773	773	0	0	0	0.0%	0.0%	0.0%
2011	780	780	780	780	0	0	0	0.0%	0.0%	0.0%
2012	788	788	788	788	0	0	0	0.0%	0.0%	0.0%
2013	798	798	798	798	0	0	0	0.0%	0.0%	0.0%
2014	828	828	828	828	0	0	0	0.0%	0.0%	0.0%
2015	879	879	879	878	0	0	-1	0.0%	0.0%	-0.2%
2016	923	923	923	919	0	0	-5	0.0%	0.0%	-0.5%
2017	945	945	945	936	-1	-1	-9	-0.1%	-0.1%	-1.0%
2018	949	940	940	939	-9	-9	-11	-0.9%	-0.9%	-1.1%
2019	1009	999	999	996	-11	-11	-13	-1.0%	-1.0%	-1.3%
2020	1054	1043	1043	1041	-11	-11	-13	-1.0%	-1.0%	-1.3%
2021	1097	1084	1083	1074	-12	-14	-23	-1.1%	-1.3%	-2.1%
2022	1133	1119	1116	1086	-13	-16	-46	-1.2%	-1.4%	-4.1%
2023	1171	1158	1155	1122	-13	-16	-50	-1.1%	-1.4%	-4.2%
2024	1209	1194	1188	1156	-15	-21	-53	-1.2%	-1.8%	-4.4%
2025	1246	1230	1219	1042	-16	-28	-204	-1.3%	-2.2%	-16.4%
2026	1313	1292	1283	1047	-21	-30	-266	-1.6%	-2.3%	-20.2%
2027	1370	1354	1343	1121	-16	-27	-249	-1.2%	-2.0%	-18.2%
2028	1435	1418	1406	1195	-17	-29	-240	-1.2%	-2.0%	-16.7%
2029	1496	1483	1470	1263	-13	-26	-234	-0.9%	-1.8%	-15.6%
2030	1553	1536	1522	1317	-17	-31	-236	-1.1%	-2.0%	-15.2%
				Average 2020 to 2030	***-15***	***-23***	***-147***	***-1.2%***	***-1.7%***	***-10.8%***

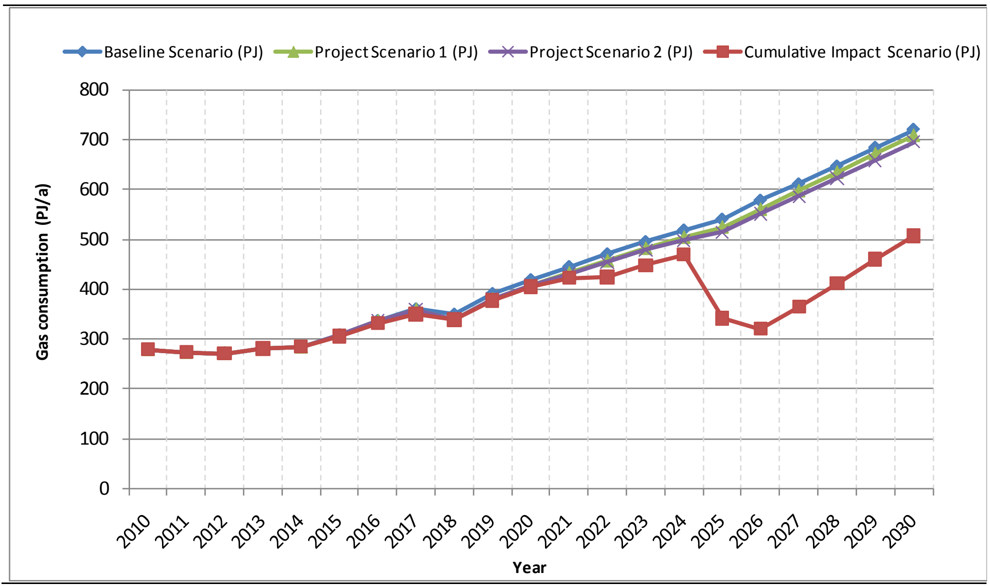
Data source: ACIL Tasman GMG Australia gas market modelling

Project Scenarios 1 and 2 show reductions in total consumption of up to 21 PJ/a and 30 PJ/a respectively, or between 1.6% and 2.3% compared to the Base Case, with an average reduction of between 15 PJ/a and 23 PJ/a (1.2% to 1.7%) over the period 2020 to 2030. The impact of the Arrow LNG Plant is relatively mild because in the absence of other new LNG projects the total assumed resource base of around 110,000 PJ/a (by 2020) is considerably larger than the reserves required to support operation of the QCLNG, GLNG and Arrow LNG Plant LNG facilities, at announced capacity, to the end of the modelling period.

In the Cumulative Scenario the modelled effect on Eastern Australian gas consumption is much more severe with a reduction of up to 266 PJ/a or about 20% compared to the Base Case, with an average reduction of 147 PJ/a or 11% over the period 2020 to 2030. This is because the additional 21 Mtpa of LNG capacity associated with the APLNG and Gladstone LNG (Fishermans' Landing) projects, as well as the incremental gas demand for the Gladstone Pacific Nickel and Boyne Island Expansion projects result in a significantly larger call on the available gas resource which drives marginal production into the high-cost area of the production cost curve.

As shown in Figure 6 and Table 2, most of the consumption impact is felt in Queensland. For Project Scenarios 1 and 2, the average decrease in consumption of between 13 PJ/a and 21 PJ/a accounts for almost all of the Eastern Australian consumption impacts over the period 2020 to 2030. For the Cumulative Scenario, the average decrease in consumption of 141 PJ/a over the same period accounts for 96% of the Eastern Australian consumption impacts. Most of the reduction in gas consumption in Queensland occurs in the electricity generation sector and, to a lesser extent, in the industrial sector which includes mineral processing and chemical manufacture.

Figure 6 **Comparison of Queensland gas consumption from 2010 to 2030 under the Base Case, Project 1, Project 2 and Cumulative Scenarios**



Data source: ACIL Tasman GMG Australia gas market modelling

Table 2 **Queensland gas consumption – differential between scenarios**

	Baseline Scenario (PJ)	Project Scenario 1 (PJ)	Project Scenario 2 (PJ)	Cumulative Impact Scenario (PJ)	Differential Baseline to Project 1 (PJ)	Differential Baseline to Project 2 (PJ)	Differential Baseline to Cumulative (PJ)	%diff Baseline to Project 1	%diff Baseline to Project 2	%diff Baseline to Cumulative
2010	279	279	279	279	0	0	0	0.0%	0.0%	0.0%
2011	274	274	274	274	0	0	0	0.0%	0.0%	0.0%
2012	271	271	271	271	0	0	0	0.0%	0.0%	0.0%
2013	282	282	282	282	0	0	0	0.0%	0.0%	0.0%
2014	284	284	284	284	0	0	0	0.0%	0.0%	0.0%
2015	308	308	308	306	0	0	-1	0.0%	0.0%	-0.5%
2016	336	336	336	332	0	0	-5	0.0%	0.0%	-1.4%
2017	360	359	359	350	-1	-1	-9	-0.2%	-0.2%	-2.6%
2018	349	340	340	338	-9	-9	-10	-2.5%	-2.5%	-3.0%
2019	390	380	380	378	-10	-10	-13	-2.7%	-2.7%	-3.2%
2020	418	407	407	405	-11	-11	-13	-2.6%	-2.6%	-3.1%
2021	444	432	431	422	-12	-14	-22	-2.7%	-3.1%	-5.0%
2022	470	457	454	424	-13	-16	-46	-2.8%	-3.5%	-9.8%
2023	495	482	478	448	-13	-16	-47	-2.6%	-3.3%	-9.4%
2024	518	504	498	469	-14	-20	-48	-2.7%	-3.9%	-9.4%
2025	540	524	514	342	-15	-25	-198	-2.8%	-4.7%	-36.6%
2026	578	560	551	320	-18	-27	-257	-3.1%	-4.6%	-44.6%
2027	610	597	586	364	-13	-25	-246	-2.2%	-4.0%	-40.3%
2028	646	634	622	412	-12	-24	-235	-1.9%	-3.7%	-36.3%
2029	684	671	658	460	-13	-26	-224	-1.9%	-3.7%	-32.8%
2030	720	708	695	507	-12	-25	-213	-1.7%	-3.4%	-29.6%
				Average 2020 to 2030	*-13*	*-21*	*-141*	*-2.5%*	*-3.7%*	*-23.4%*

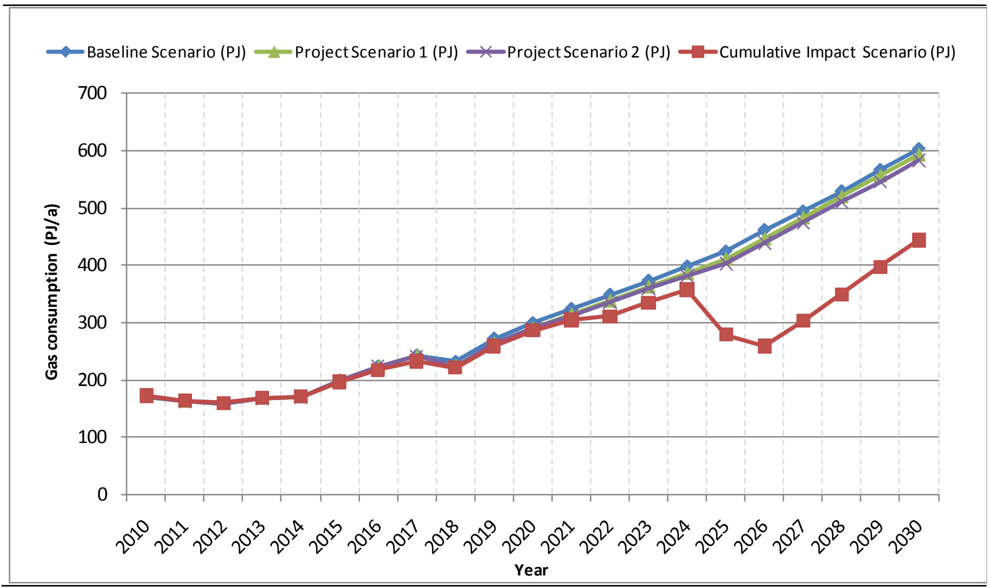
Data source: ACIL Tasman GMG Australia gas market modelling

Figure 7 and Table 3 shows the extent of the impacts on the Queensland electricity generation sector.

The impacts under Project Scenarios 1 and 2 are again mild, with reductions of between 13 PJ/a and 21 PJ/a (2.5% to 3.7%) compared to the Base Case.

For the Cumulative Scenario, the effects on gas consumption for electricity generation in Queensland are much greater, with a reduction of 108 PJ/a or about 23% on average over the period 2020 to 2030. Total gas consumption for power generation in Queensland stands at around 286 PJ/a in 2020, but falls to a low of 259 PJ/a in 2026 as more LNG capacity comes on line, before rising again in later years of the projection period.

Figure 7 **Queensland gas consumption for electricity generation from 2010 to 2030 under the Base Case, Project 1, Project 2 and Cumulative Scenarios**



Data source: ACIL Tasman GMG Australia gas market modelling

Assuming an average efficiency of the gas-fired generation fleet of 40% (average for combined cycle gas turbine [CCGT] and open cycle gas turbine [OCGT]), consumption of 286 PJ/a of gas for electricity generation in 2020 would imply total sent-out gas fired generation of around 31,800 GWh. The most recent forecasts of scheduled electricity demand for Queensland prepared by the Australian Energy Market Operator (AEMO) range between 58,800 GWh (Low Demand Scenario) and 97,900 GWh (High Demand Scenario) by 2020, with a medium demand forecast of about 74,150 GWh (AEMO, 2010). Adopting the medium demand forecast, this implies that under the Cumulative Scenario gas-fired generation in 2020 will account for about 43% of scheduled electricity generation in Queensland, compared to 44% under Project Scenarios 1 and 2, and 45% under the Base Case.

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Table 3 **Queensland gas consumption for electricity generation**

	Baseline Scenario (PJ)	Project Scenario 1 (PJ)	Project Scenario 2 (PJ)	Cumulative Impact Scenario (PJ)	Differential Baseline to Project 1 (PJ)	Differential Baseline to Project 2 (PJ)	Differential Baseline to Cumulative (PJ)	%diff Baseline to Project 1	%diff Baseline to Project 2	%diff Baseline to Cumulative
2010	173	172	172	173	-1	-1	0	-0.6%	-0.6%	0.0%
2011	164	163	163	164	-1	-1	0	-0.6%	-0.6%	0.0%
2012	160	159	159	160	-1	-1	0	-0.6%	-0.6%	0.0%
2013	169	168	168	169	-1	-1	0	-0.6%	-0.6%	0.0%
2014	171	170	170	171	-1	-1	0	-0.6%	-0.6%	0.0%
2015	199	198	198	197	-1	-1	-2	-0.5%	-0.5%	-1.2%
2016	224	223	223	217	-1	-1	-7	-0.4%	-0.4%	-3.0%
2017	243	242	242	233	-1	-1	-10	-0.4%	-0.4%	-4.1%
2018	232	224	224	221	-8	-8	-10	-3.3%	-3.3%	-4.5%
2019	272	263	263	260	-9	-9	-13	-3.3%	-3.3%	-4.7%
2020	299	290	290	286	-9	-9	-13	-3.1%	-3.1%	-4.3%
2021	324	314	313	305	-10	-11	-19	-3.2%	-3.5%	-5.8%
2022	349	338	336	311	-11	-13	-37	-3.2%	-3.8%	-10.7%
2023	373	362	360	335	-11	-13	-38	-2.9%	-3.6%	-10.3%
2024	398	386	382	357	-12	-16	-41	-3.0%	-4.1%	-10.2%
2025	424	411	403	279	-13	-20	-144	-3.1%	-4.8%	-34.1%
2026	461	446	439	259	-15	-22	-202	-3.4%	-4.8%	-43.8%
2027	494	483	474	303	-11	-20	-191	-2.2%	-4.0%	-38.6%
2028	529	520	510	350	-9	-19	-179	-1.8%	-3.6%	-33.9%
2029	566	556	546	398	-10	-20	-168	-1.7%	-3.6%	-29.8%
2030	602	593	583	444	-10	-19	-159	-1.6%	-3.2%	-26.3%
				Average 2020 to 2030	***-11***	***-17***	***-108***	***-2.6%***	***-3.8%***	***-22.5%***

Data source: ACIL Tasman GMG Australia gas market modelling

After 2020, modelled gas consumption for electricity generation in Queensland reaches a low of 259 PJ/a in 2026 under the Cumulative Scenario. This implies gas-fired generation of about 28,500 GWh. If demand continues to grow over this period at 3.6% per year (the same rate of growth implied by the current AEMO medium demand forecast) then total scheduled electricity demand in Queensland will rise to about 91,700 GWh by 2026. Hence the modelled level of consumption under the Cumulative Scenario would account for about 31% of scheduled electricity generation in 2026.

The analysis therefore indicates that, even at the time of greatest market impact under the Cumulative Scenario, the Queensland government's 18% gas generation target is likely to be met.

3.2 Impacts on delivered gas prices

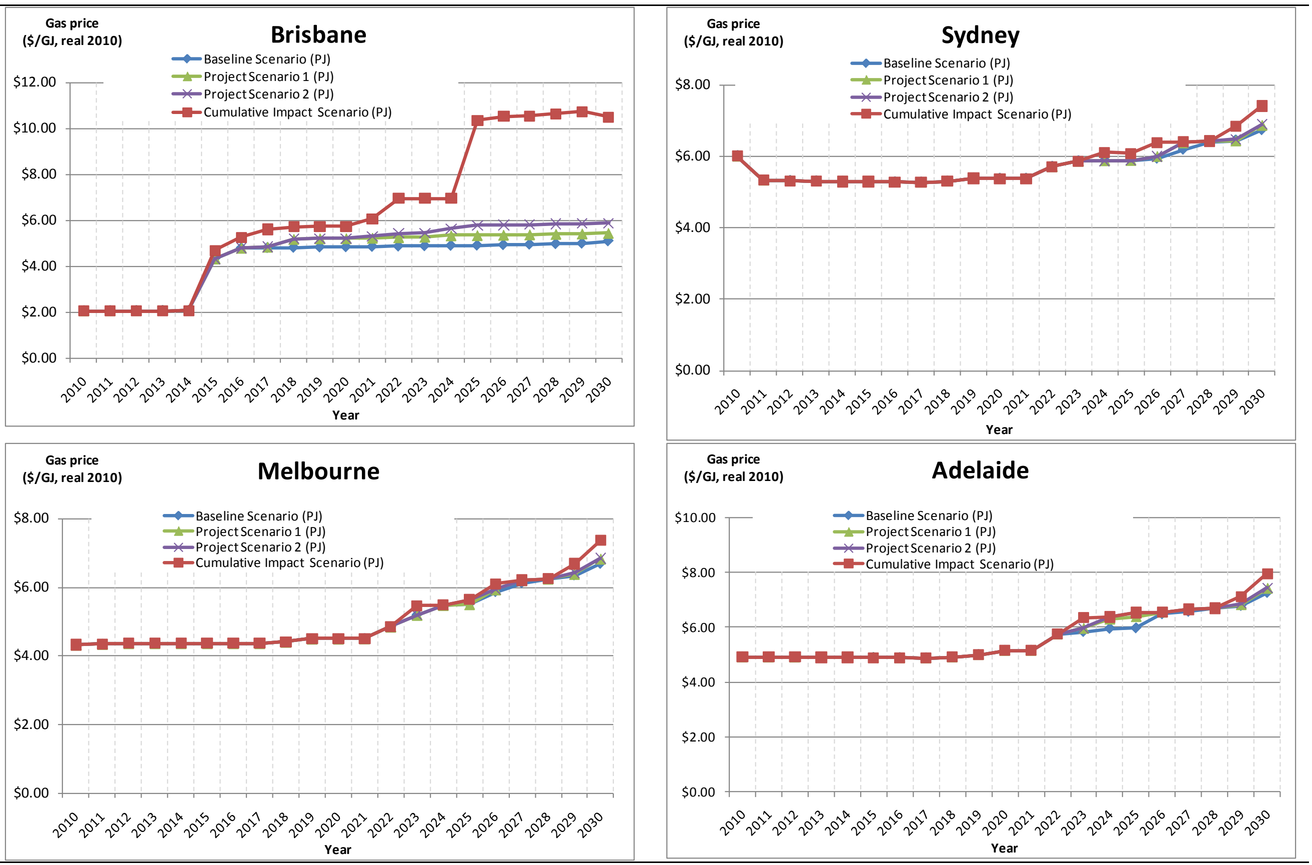
3.2.1 A note on modelled gas prices

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 and so forth. 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.

3.2.2 Price results

The results of the four scenarios (Base Case, Project 1 and 2, and Cumulative) in terms of impact on wholesale delivered gas prices at the mainland capital cities in Eastern Australia are summarised in Figure 8.

Figure 8 **Impact of LNG exports on wholesale gas prices**



Data source: ACIL Tasman analysis

All prices are expressed in Australian dollars per gigajoule (real, 2010 dollar terms). The modelled prices are inclusive of transportation costs at system average load factor and are effectively the "market clearing" prices at each location. In practice, the prevalence of long-term contracts with widely varying commercial terms and conditions means that different end-users are likely to face significantly different prices. The modelled prices in effect represent the marginal price of gas that will influence prices faced by consumers looking to recontract at different points in time rather than a daily average price prevailing in the market.

The results shown in Figure 8 demonstrate that the Arrow LNG Plant by itself (as represented in the Project Scenarios 1 and 2) will have limited impacts on wholesale gas prices in Eastern Australia, with only minor effects outside Queensland. In Queensland (Brisbane City Gate) prices are initially much lower than the other states because of the influence of ramp-up gas. All scenarios show a sharp rise in Queensland prices with the removal of the ramp-up effect following LNG commissioning. Project Scenario 1 sees modelled wholesale price increases of up to $0.44/GJ or about 9%, with an average price increase of 8% over the period 2020 to 2030. For Project Scenario 2, the corresponding price increases are up to $0.87/GJ or about 18%, with an average price increase of 14%. The average price impacts over the same period in New South Wales, Victoria and South Australia range from 0.5% to 2.2%.

Price effects are much more marked under the Cumulative Scenario. In Queensland modelled wholesale prices under this scenario rise sharply with the commissioning of the first LNG plants around 2015. Further steep price rises occur over the next decade as additional LNG trains are commissioned. The average price uplift under the Cumulative Scenario (compared to the Base Case) over the period 2020 to 2030 is around $3.78/GJ or 76%. The average price impacts over the same period in New South Wales average 3.2%; in Victoria 2.6%; and in South Australia 3.8%. The rise in Queensland price to more than $10/GJ (real 2010) after 2025 is almost certainly exaggerated: it reflects a modelling assumption of a very high international LNG price which is designed to ensure that the model fully dispatches all LNG liquefaction capacity. In practice, domestic gas prices are unlikely to rise to above LNG netback prices. Assuming a long-run oil price of around US$80/bbl, LNG netback could reasonably be expected to lie in a range from around A$7.50 to $8.50/GJ.

3.3 Risk mitigation

The preceding analysis demonstrates that, while the risks to domestic gas supply and pricing are modest in the case of a single project in addition to those already committed, there is potential for more significant impacts arising from more rapid expansion of CSG-based LNG capacity. The most severe impacts on the Eastern Australian domestic market would arise in circumstances where LNG expansion "gets ahead" of actual CSG production capacity. Such a situation could arise if actual CSG production performance were to fall seriously short of expected performance. For reasons discussed below, we consider this risk to be low. Nevertheless, the risk to domestic gas availability and price is likely to bear some relationship to the aggregate scale of CSG LNG production, if for no other reason than the relative sizes of the two market sectors and the consequent leverage that any disruption in supply to the LNG plants would potentially exert on the domestic market.

While we have assumed an aggressive ramp up of CSG production capability to 4,500 PJ/a (across all price points) by 2020, with an implied underlying reserves base of 110,000 PJ, even this rich CSG resource would not be capable of supporting all of the LNG developments under the cumulative impact assumptions (which total some 59 Mtpa at full development) without very significant impacts on gas consumption and pricing in Queensland.

This risk will be mitigated to some extent by normal commercial market mechanisms and disciplines. Given the very large scale of the CSG LNG projects and the correspondingly large commercial commitments involved, it is reasonable to assume that these projects will only proceed after very thorough assessment of the CSG resource base. Investment and funding approvals will require high levels of confidence in the size and deliverability of gas resources to support the LNG developments, and commercial stakeholders including investors, debt providers and customers are likely to require levels of resource redundancy that will provide a buffer for domestic markets.

The risk is further mitigated by the Queensland Government's current policies relating to gas supply security provide further risk mitigation. In November 2009, the Queensland Government announced the following policy position in relation to security of gas supply (DEEDI, 2010):

> It estimated that Queensland has around 500 years of gas supply at current levels. Given this, the Government has rejected the option of requiring a percentage of gas from all fields to go to domestic supply.
>
> However, the Government will establish a capacity for future fields proposed for exploration to be reserved for domestic gas supply, should it be determined that domestic gas supply is constrained. A Gas Commissioner will be established to ensure this is managed in a transparent way.
>
> The Government will also facilitate the development of a short-term gas trading market by 2011.

In effect, the Queensland Government policy ensures that security of domestic gas supply is subject to ongoing scrutiny, with identified response options in the event that significant constraints are anticipated.

4 Conclusions

The aim of this report was to assess the potential impact of the Arrow LNG Plant on the availability and price of gas to service domestic markets in Eastern Australia, including the potential impact on gas-fired electricity generation. The analysis shows that under aggressive but not unreasonable assumptions about the supply cost curve for Queensland CSG, if the Arrow LNG Plant is the only LNG project above Baseline it is likely to have a relatively mild effect on Eastern Australian gas consumption and prices. Those effects would be felt mainly in Queensland, where the modelling results show domestic gas consumption would fall by between 2.5% and 3.7 % on average over the period 2020 to 2030, and wholesale gas prices would rise by between 8% and 14% on average over the same period.

In the unlikely event that the Arrow LNG Plant and all other current CSG-based LNG project proposals were to proceed to full development, along with those projects that have already reached final investment decision, the modelling indicates potential for major impacts on domestic gas availability and pricing in Queensland. Even with an assumed resource base of some 110,000 PJ across a range of price points— approximately four times the proven and probable reserves of CSG in Queensland as at mid 2010—there are very significant impacts on modelled gas consumption and price, particularly in the period after 2020. Total gas consumption in Eastern Australia would be some 236 PJ/a lower by 2030, with 213 PJ of this reduction occurring in Queensland. Most of the reduction (159 PJ/a in Queensland) would occur in the electricity sector, and to a lesser extent in the industrial and minerals processing sectors. Nevertheless, the levels of gas use in electricity generation would be likely to exceed the Queensland government's targeted minimum levels of gas use for electricity generation in 2020 and in all subsequent years of the model simulation.

The modelled price effects under the Cumulative Scenario are much stronger than for the Project Scenarios. In Queensland modelled wholesale prices under this scenario rise by an average of $3.78/GJ or 64 % over the period 2020 to 2030. The average price impacts in the southern states over the same period are much smaller with an increase in New South Wales averaging 3.2%; in Victoria 2.6%; and in South Australia 3.8%.

In practice, the extent of the consumption and price impacts from rapid expansion of LNG production in Eastern Australia will depend on the size and timing of that expansion and on the size of the producible CSG resource that is ultimately established. The modelled effects of the Cumulative Scenario would be less severe if the scale and pace of expansion was slower, or if the resources of CSG and production capability available at a given price level were higher. Conversely, faster expansion of the industry and/or a smaller, higher cost CSG reserve than has been assumed would amplify the modelled consumption and price effects.

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A Appendix A – GMG Australia gas model

The *GasMark Global Australia* (GMG) 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.

Modelled price impacts of CSG LNG developments

Settlement

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

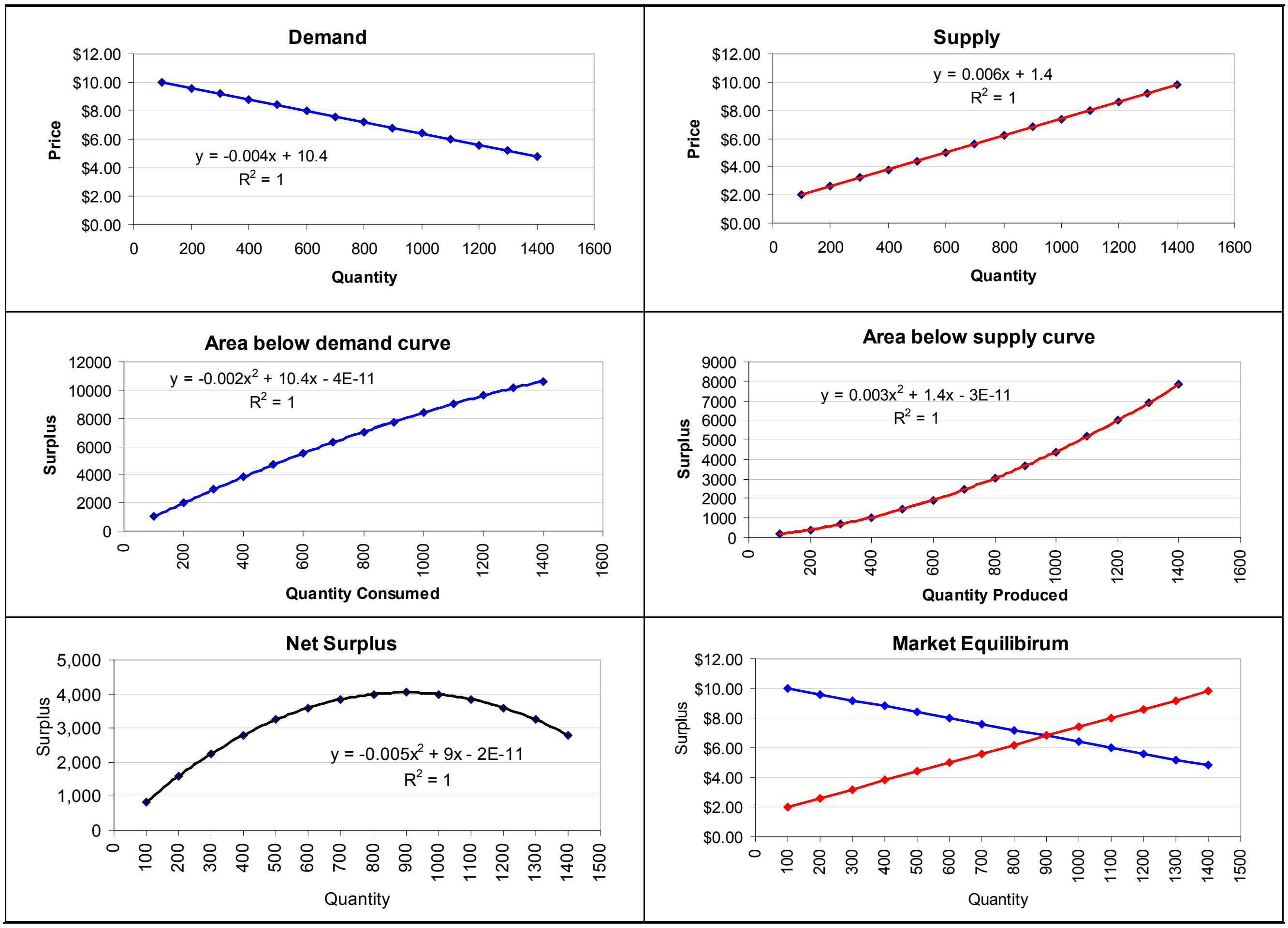
The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory, consists 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 A1 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure A1 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure A1 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 consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units of consumption. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

Figure A1 **Simplified example of market equilibrium and settlement process**



Data source: ACIL Tasman

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

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

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

Data inputs

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

The inputs to GMG can be categorised as follows:

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

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