

# **Projections of Gas and Electricity Used in LNG**

**Prepared for**  
**Australian Energy Market Operator**

**Lewis Grey Advisory**

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**Contents**

**Executive summary** ..... iv

Terms of reference ..... iv

This report ..... iv

Summary of findings ..... v

Scenarios ..... v

Methodology ..... v

Projections ..... vi

**1. Introduction** ..... **1**

1.1 LNG exports from Gladstone ..... 1

1.2 The export projects ..... 2

1.3 Information cut-off date ..... 2

**2. Scenarios** ..... **3**

2.1 Determining factors ..... 3

2.1.1 AEMO planning and forecasting scenarios ..... 3

2.1.2 LNG projects under construction ..... 4

2.1.2.1 Further trains for these projects ..... 5

2.1.3 Planned projects ..... 5

2.1.4 Gas resource availability ..... 6

2.1.5 Global LNG demand ..... 7

2.1.6 Competition from other suppliers ..... 8

2.1.7 LNG pricing ..... 10

2.2 Scenario selection ..... 11

**3. Methodology** ..... **13**

3.1 Overview ..... 13

3.1.1 Historical data ..... 15

3.2 Gas exported ..... 15

3.3 Energy used in LNG production (liquefaction) ..... 17

3.3.1 Energy sources ..... 17

3.3.2 Testing gas usage ..... 18

3.3.3 Liquefaction gas usage ..... 18

3.4 Energy used in gas transmission ..... 19

3.5 Energy used in gas storage ..... 21

3.6 Energy used in gas supply ..... 21

3.6.1 Gas supply ..... 21

3.6.2 Supply model ..... 23

3.6.3 Ramp gas ..... 24

3.6.4 Gas field and processing plant energy usage ..... 26

3.6.4.1 Operated gas ..... 26

3.6.4.2 Non-operated gas ..... 27

3.6.5	Total energy usage .....	27
3.7	Estimates of peak gas and electricity demand .....	28
3.8	Sensitivity of gas and electricity demand to gas and electricity prices.....	28
3.8.1	Gas demand .....	28
3.8.2	Electricity demand.....	29
3.9	Potential for demand-side participation by the LNG plants in response to high electricity prices or high electricity demand .....	29
3.10	Confidence in the base scenario projections .....	30
3.11	Calculating monthly estimates .....	31
<b>4.</b>	<b>Projections .....</b>	<b>32</b>
4.1	Annual projections .....	32
4.2	Peak demand projections .....	35
4.3	Monthly projections .....	37

**Appendix A. Abbreviations****Disclaimer**

This report has been prepared solely for the Australian Energy Market Operator for the purpose of assessing gas and electricity use in LNG production. Lewis Grey Advisory bears no liability to any party (other than specifically provided for in contract) for any representations or information contained in or omissions from the report or any communications transmitted in the course of the project.

## Executive summary

### Terms of reference

The Australian Energy Market Operator (AEMO) has engaged Lewis Grey Advisory (LGA) to provide the following consultancy services:

1. Delivery of an updated report and dataset relating to historical data and forecasts of gas and electricity consumption (annual and maximum/peak daily) related to LNG export for the next 25 years (2014-15 to 2040-41) under various scenarios and conditions.
2. Delivery of an update to the report and to be delivered by 30 September 2015.
3. Provide updates to the forecast triggered by major events as requested by AEMO.

These deliverables should be developed using the Consultant's analysis and market intelligence as well as direct consultation with industry stakeholders. It is imperative that clear reasoning is provided where the Consultant's forecasts differ from information provided by stakeholders.

The deliverables must be suitable for publishing on the AEMO website. The forecasts themselves will be used as inputs into the NEFR and NGFR. More specifically, this project involves:

- Industry (LNG) stakeholder consultation (for report and mid-year update):
  - a. Review of templates/questionnaires for industry stakeholders
  - b. Assessing stakeholder responses to questionnaires (if available) and working with AEMO on any required follow-up with industry stakeholders.
- Internal AEMO stakeholder consultation through the engagement.
  - a. Working with key AEMO stakeholders to answer questions on the deliverables and making appropriate revisions to draft deliverables based on AEMO feedback.
  - b. A transfer of knowledge to members of AEMO's Energy Forecasting team and other teams as appropriate regarding the LNG sector consumption modelling.
- Development of a report and mid-year update, suitable for publishing on the AEMO website, detailing forecasts of LNG production (in million tonnes per annum (Mtpa)) from eastern and south-eastern Australia as well as the gas and electricity consumption associated with this production. Key aspects to be addressed as part of this document are described in Section 2.2.
- Provision of an Excel database(s) proving data underpinning any chart, figure and/or forecasts presented in the report and the mid-year update.
- Provide updates to the forecasts triggered by major events as requested by AEMO on an ad-hoc basis

### This report

This report fulfils the requirements of item 1) above. Other items have been or will be complied with separately. It is noted that the required forecasts of LNG production and the gas and electricity usage associated with this production are the result of modeling undertaken by LGA based largely on information in the public domain, much of it provided by the stakeholders and AEMO on their websites, including similar forecasts prepared by Jacobs in 2014 and by Core Energy in 2013. Use of confidential material provided by the stakeholders is limited and this material and results derived from it are not presented in this report.

## Summary of findings

Queensland Curtis LNG (QCLNG) commenced exports from its first LNG train on Curtis Island, near Gladstone, in January 2015. QCLNG is currently completing its second train and will soon be joined by two other export projects: Gladstone LNG (GLNG); and Australia Pacific LNG (APLNG). All six committed LNG trains, each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year, are scheduled to be operational by 2016. A fourth major project, that of Arrow Energy, has recently been cancelled as a stand-alone project but may contribute its gas reserves to a third train at one of the existing projects or another, smaller project.

The purpose of this study is to provide AEMO with consistent estimates of the gas supply required for export, including gas used in the supply chain, and grid-supplied electricity usage in the supply chain. These estimates will be used in the preparation of AEMO's 2015 National Electricity Forecast Report (NEFR) and National Gas Forecast Report (NGFR), ensuring consistency in regard to LNG assumptions in these two reports.

The key elements of the study are:

1. Scenarios concerning the overall levels of exports.
2. Methodology for estimating electricity and gas used in the LNG supply chain
3. Projections of electricity and gas used in LNG export based on applying the methodology to the scenarios.

## Scenarios

Since the final investment decisions on the six trains were made, the prospects of further trains being committed have diminished significantly. The scenarios selected for this study therefore have relatively limited variation:

- Base Scenario –the six trains operating at their contracted levels of capacity, approximately 24 Mtpa in total, and reaching that level on the most recent ramp-up schedules released by LNG project operators. The intention of this scenario is to reflect the project stakeholders' export objectives.
- Low Scenario – the six trains operating 15% below contract (approximately 20 Mtpa), with slower ramp-up
- High Scenario – the six trains operating at boilerplate capacity (above contract) with faster ramp up, plus a seventh train of 4.2 Mtpa capacity. Total production ultimately reaches 29 Mtpa.

LGA has not formed any view as to the probabilities that might be attached to the low and high scenarios.

## Methodology

LGA has used a similar approach to modelling gas and electricity usage to supply LNG exports as used by Jacobs in preparing the 2014 "Projections of Gas and Electricity Used in LNG" (the 2014 Projections). The model is based on public domain information and works backwards from the volume of LNG exported through the liquefaction, transmission and production components of the supply chain. It does not take into account gas used in shipping or energy used in drilling, which is mainly diesel rather than gas or electricity.

Key assumptions and parameters for each component are summarised below:

- Liquefaction –it is understood that the plants all use gas for their electricity and compression requirements. 8% of gas input to the plant is estimated to be used in modern plants.
- Transmission – the large diameter pipelines used by each project have sufficient capacity to ship daily quantities for two trains without mid-point compression. In the High Scenario, use of one pipeline by the seventh train will necessitate installation of mid-point compression.

- Gas Supply – gas is largely sourced from each projects’ coal seam gas (CSG) reserves in the Surat and Bowen Basins and although the legacy CSG fields are gas powered, the new developments are all to be powered by electricity sourced from the National Electricity Market (NEM) via the Queensland transmission grid. QCLNG and GLNG have also purchased third party gas for up to 25% of their requirements and as the third party sources are either not known or known to be well outside the NEM, they are all assumed to be gas powered. Field and Gas Processing Plant energy use are calculated using parameters estimated by LGA from actual usage data provided by the Queensland Department of Natural Resources and Mines and AEMO. The electricity data and usage figures are confidential but represent an increase compared to 2014 estimates.

**Table E 1 Energy used in gas processing (% of net gas energy produced)**

	<b>QCLNG</b>	<b>GLNG</b>	<b>APLNG</b>	<b>Average</b>
Gas driven plant	5.0%	6.4%	6.5%	6.0%
Electricity driven plant	Confidential	Confidential	Confidential	Confidential

## Projections

Total LNG export projections are presented in Figure E 1, together with the equivalent 2014 projections prepared by Jacobs<sup>1</sup> (dashed lines). The Base scenarios are very similar, reflecting the limited changes to public information on the LNG projects’ start-up timing and contracted volumes. There are more significant differences in the High and Low scenarios: in the High scenario the seventh train now comes in two years later; and in the Low scenario exports are 5% lower than previously because the contract take-or-pay level is assumed to be 85% instead of the previous 90%.

<sup>1</sup>These are Jacobs August Revised Projections

**Figure E 1 Total LNG export projections**

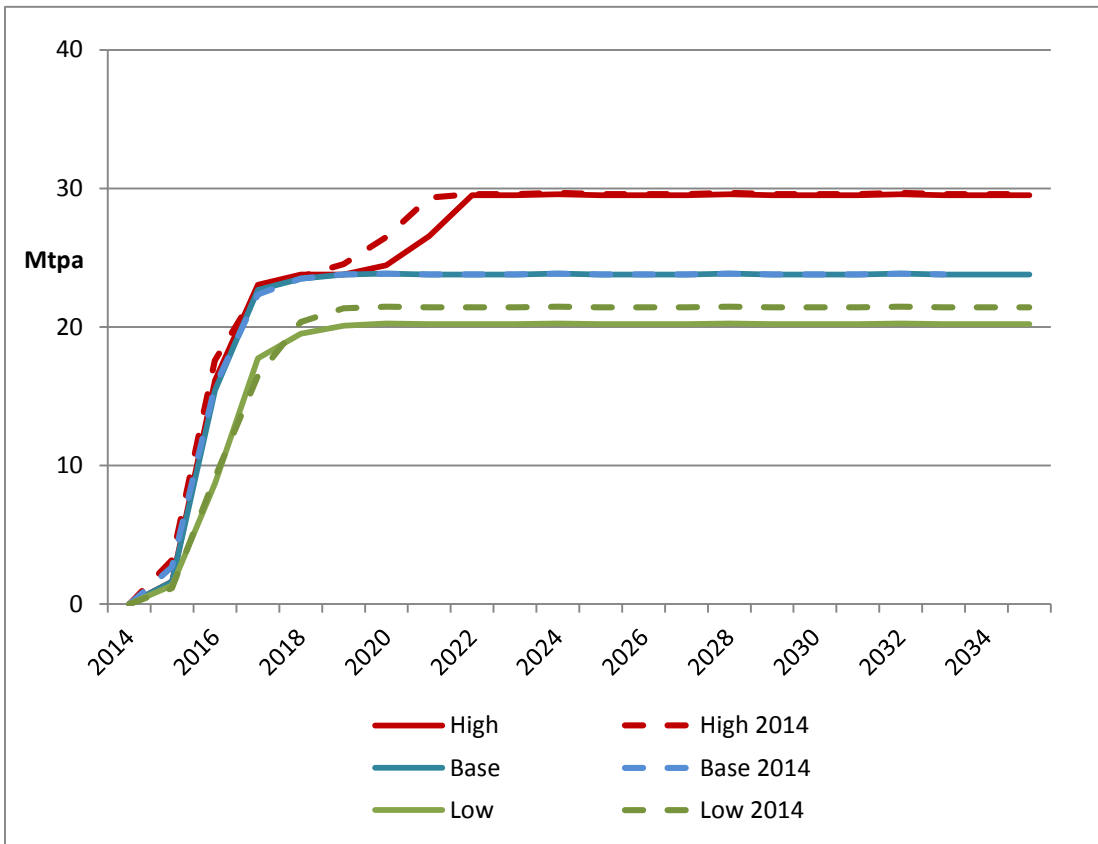
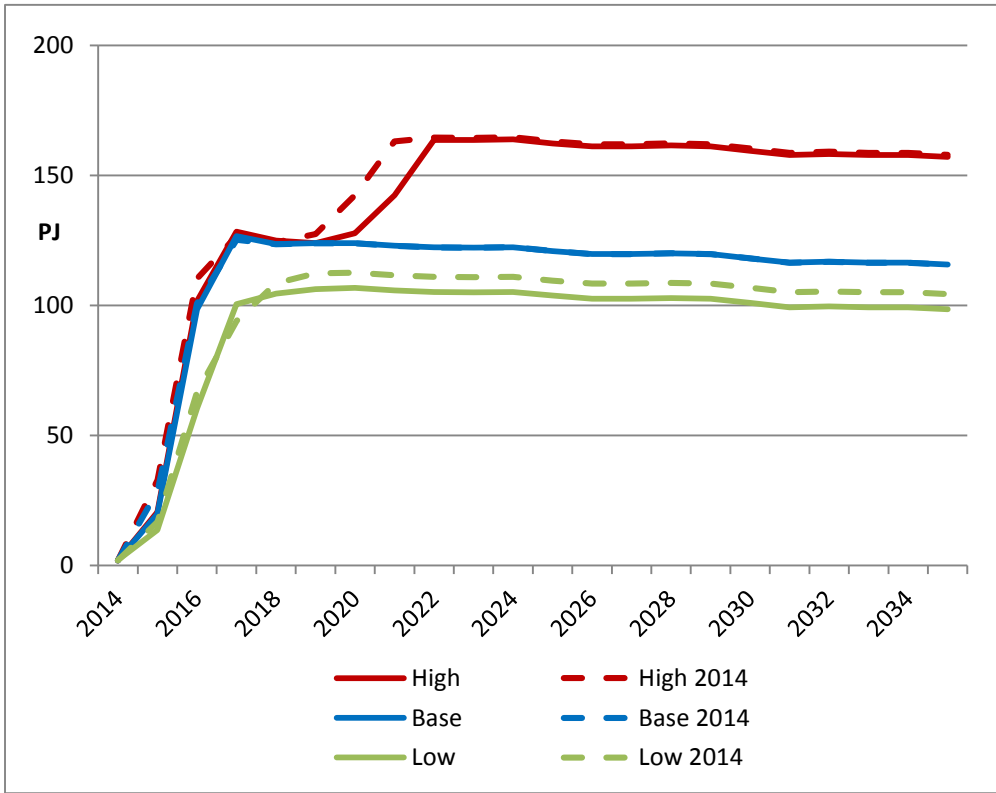


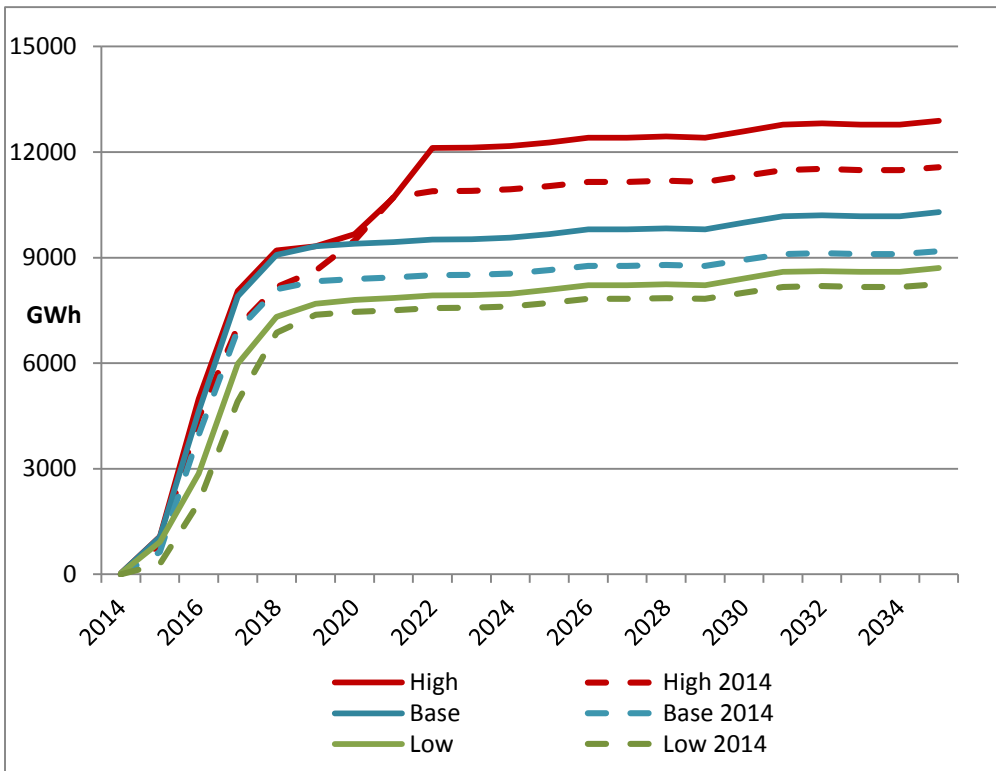
Figure E 2 and Figure E 3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production. For gas usage the differences between current and 2014 projections simply follow the differences in export projections discussed above, as the usage parameters that have changed the most (APLNG’s upstream gas use) apply only to small volumes of production. However the electricity usage projections have substantially increased compared to 2014 because the estimates of electricity used per TJ of gas produced have increased. Further revisions to these estimates as more data becomes available over coming months may change the electricity usage projections in the Update Report to be released by September 2015.



**Figure E 2 Total gas used in liquefaction and production**



**Figure E 3 Total grid electricity usage**



# 1. Introduction

## 1.1 LNG exports from Gladstone

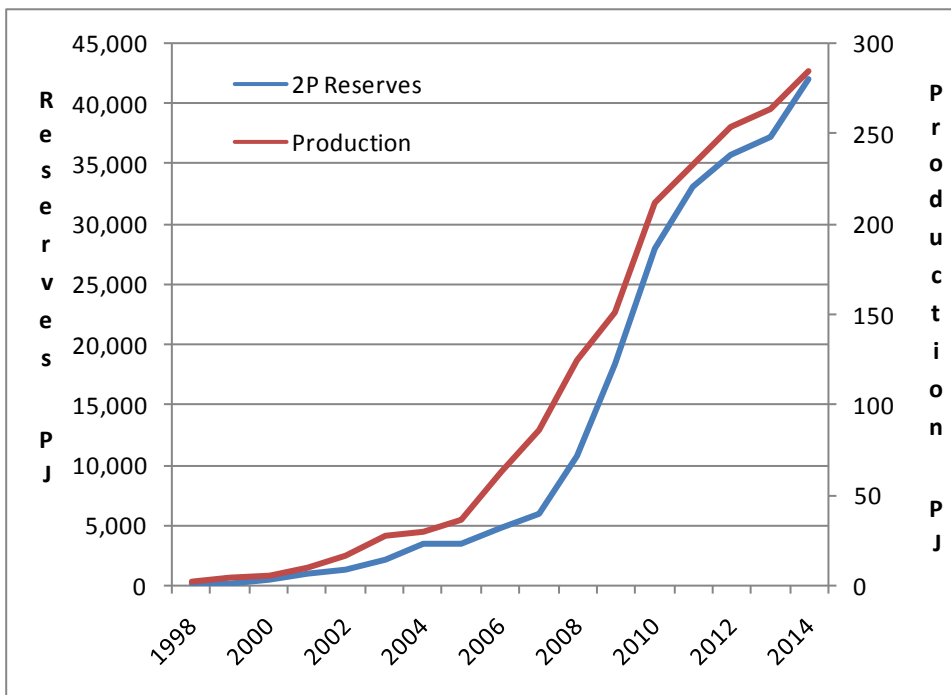
Gas reserves in eastern Australia were supplied solely to the domestic market from the discovery of natural gas in the nineteen sixties until January 2015, when the first shipment of LNG left Gladstone for Singapore. The turnaround from modestly scaled domestic supply to much larger scale exports followed the steady development of economic extraction technologies for coal seam gas (CSG). This led to reserves of CSG outgrowing domestic demand, at which point additional market options were sought.

Worldwide, liquefied natural gas (LNG) has provided the most advantageous technology to monetise excess gas. LNG is cheaper than pipeline gas over long distances, provides more market flexibility for buyers and sellers and offers higher margins than alternative transformation options such as gas to liquids.

LNG supplies approximately 9% of global gas demand, principally in countries whose native supplies are limited, such as Japan, and saw rapid growth and high prices during the oil price surge from 2003 to 2008. Since 2007 ten proposals have been put forward to export LNG from liquefaction plants in eastern Australia with eight proposed for the Queensland coast and one each in New South Wales and South Australia.

Figure 1-1 illustrates the development of Queensland CSG reserves and production from 1998 to 2014. Since 2007 the reserves have been developed to support far more than the 300 PJ/yr used domestically and the period to 2017 will see a dramatic reshaping of this chart – reserves will remain steady but production will increase six fold to supply exports using 1,400 PJ/yr.

Figure 1-1 Queensland CSG Reserves and Production



Source: Queensland Department of Natural Resources and Mines

## 1.2 The export projects

Three large LNG export projects are nearing completion on Curtis Island, near Gladstone: Queensland Curtis LNG (QCLNG); Gladstone LNG (GLNG); and Australia Pacific LNG (APLNG). QCLNG completed its first train in December 2014 and shipped its first gas the following month. The other five trains under construction, each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year, are scheduled to make their first deliveries in 2015 and 2016. The six trains will use approximately 4,750 PJ each over 20 years, or 28,500 PJ in total.

A fourth major project, that of Arrow Energy, has recently been cancelled and Arrow Energy is seeking alternative means of monetising its CSG resources. Options include combining with one or more of the existing projects to improve its economics and their reserves positions. All three projects nearing completion have planning approval for more than two trains. Other proposed eastern Australian export projects are no longer under consideration.

The purpose of this study is to provide AEMO with consistent estimates<sup>2</sup> of the gas supply required for export, including gas used in the supply chain, and grid-supplied electricity usage in the LNG supply chain. These estimates will be used in the preparation of AEMO's 2015 NEFR and NGFR, in the same manner as in 2014.

The key elements of the study presented in the following sections are:

1. Scenarios concerning the overall levels of exports, focussing primarily on: the numbers and timing of trains constructed; full production levels of exports for each train; and timing of ramp-up to full production.
2. Methodology for estimating electricity and gas used in the LNG supply chain
3. Projections of electricity and gas used in LNG export based on applying the methodology to the scenarios.

## 1.3 Information cut-off date

The modelling documented in this report incorporates information available as at 4<sup>th</sup> March 2015. Since that date the following potentially material information has become available:

1. On 9<sup>th</sup> April it was announced that Shell, a joint venture partner in Arrow Energy, has initiated a takeover of BG Group, the majority participant in QCLNG. This has led Australian market analysts to hypothesize that Arrow Energy gas will be monetised by supplying an additional train or trains at QCLNG's Curtis Island plant. However QCLNG did not feature in a list of potential LNG projects named by Shell's CFO Mr Henry when he spoke to analysts last week after the deal was announced<sup>3</sup>.

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<sup>2</sup> In particular, changes in export outlook can be consistently incorporated into both gas and electricity forecasts

<sup>3</sup> The Australian, 13<sup>th</sup> April 2015

## 2. Scenarios

### 2.1 Determining factors

The principal determinants of the scenarios for these projections are relatively unchanged from 2014 and include: AEMO planning and forecasting scenarios; LNG projects under construction and planned; gas resource availability; global LNG demand and competition from other suppliers.

#### 2.1.1 AEMO planning and forecasting scenarios

AEMO and the industry-based Scenarios Working Group (SWG) have developed three scenarios representing high, medium and low energy consumption for both gas and electricity from centralised sources<sup>4</sup>, for use in AEMO’s planning studies in 2014 and 2015<sup>5</sup>. The three scenarios are broadly defined in Table 2-1. Scenario assumptions related to domestic gas and LNG exports are set out in Table 2-2.

**Table 2-1 AEMO 2015 Scenarios**

Scenario Factor	High energy consumption from centralised sources	Medium energy consumption from centralised sources	Low energy consumption from centralised sources
Energy consumption	High	Medium	Low
Type of consumer	Low engagement	Highly engaged	Highly engaged
Economic activity	High	Medium	Low

**Table 2-2 AEMO Scenario Gas and LNG assumptions**

Scenario	Gas and LNG Assumptions
<b>Medium Energy</b>	<b>Domestic gas production</b> and <b>global LNG</b> markets continue as per market expectations (central estimate) and are consistent with current growth in Australia’s production levels.
<b>High Energy</b>	<p><b>Domestic gas production</b> is higher than expected (exceeding production required for LNG). Australia’s international competitiveness for gas exports is higher than the medium scenario.</p> <ul style="list-style-type: none"> <li>○ Hurdles for fuel substitution are expected to discourage switching between gas and electricity usage. This means, for example, if gas prices were low, industry would not be able to easily switch from electricity to gas due to either prohibitive infrastructure costs or specific production processes which will not allow it.</li> </ul> <p>Global demand for <b>LNG</b> is stronger than in the medium scenario, encouraging higher exports.</p>

<sup>4</sup> A centralised source refers to the national electricity transmission grid for electricity and the national gas transmission pipeline for gas

<sup>5</sup> 2014 Planning and Forecasting Scenarios, AEMO 11 February 2014.

Scenario	Gas and LNG Assumptions
<b>Low Energy</b>	<p><b>Domestic gas production</b> is more difficult than expected. Australia's international competitiveness is lower than the medium scenario. Fuel substitution hurdles discourage fuel switching between electricity and gas.</p> <p><b>Global LNG demand</b> is weaker than the medium scenario and there is low penetration of <b>gas as a transport fuel</b>.</p>

### 2.1.2 LNG projects under construction

The three Queensland LNG export projects outlined in section 1.2 have the following features:

- 1) Each project has sold gas under long-term contracts with two or more buyers. QCLNG will also sell to BG Group portfolio customers in Chile, China and Singapore. The terms of all contracts are 20 years or longer, though it is not known whether the contract periods start at first supply or when full off take (plateau production) is reached. It is known however that as at the end of 2014 GLNG had sold 13 commissioning cargoes that were to be delivered during the commissioning period before contract supply starts up<sup>6</sup>.
- 2) Each project is constructing 2 LNG processing trains, of 3.9 to 4.5 Mtpa capacity, on Curtis Island off Gladstone. QCLNG's first train commenced operations in December 2014.

**Table 2-3 Gladstone LNG Project Parameters**

Project	Partners	Planned Capacity (Mtpa)	Contracts	
			Party	Volume (Mtpa)
<b>QCLNG<sup>7</sup></b>	BG Group (73.75%)	8.5	<i>CNOOC</i>	3.6
	CNOOC (25%)		<i>Tokyo Gas</i>	1.2
	Tokyo Gas (1.25%)		<i>Chubu Electric</i>	0.5
			Total	5.3
<b>GLNG<sup>8</sup></b>	Santos (30%)	7.8	<i>Petronas</i>	3.6
	Petronas (27.5%)		<i>Kogas</i>	3.6
	Total SA (27.5%)		Total	7.2
	Kogas (15%)			

<sup>6</sup>STO 2014 Investor Seminar, 26 November 2014

<sup>7</sup>bgdatabook 2014

<sup>8</sup> STO 2014 Investor Seminar, 26 November 2014

Project	Partners	Planned Capacity (Mtpa)	Contracts	
			Party	Volume (Mtpa)
APLNG <sup>9</sup>	Origin Energy (37.5%)	9.0	<i>Sinopec</i>	7.6
	Conoco Phillips (37.5%)		<i>Kansai Electric</i>	1.0
	Sinopec (25%)		Total	8.6

- 3) Each project is developing gas supply capacity based on equity CSG reserves in the Bowen and Surat Basins. GLNG and QCLNG are also sourcing gas supply from third party owned CSG and conventional gas resources in the Cooper Basin.
- 4) Each project has constructed its own transmission pipeline to deliver gas to Curtis Island. The pipelines are interconnected at their upstream and downstream ends to facilitate operational gas management and trading. The QCLNG pipeline is held for sale to the Australian Pipeline Trust (APA) and the other projects are also contemplating sales of their pipelines in order to restructure their balance sheets.
- 5) In the above table project ownership is stated on an aggregate basis across production and liquefaction. In some projects percentages are different in each component.

### 2.1.2.1 Further trains for these projects

APLNG<sup>10</sup> has environmental approval for 4 trains and QCLNG<sup>11</sup> and GLNG<sup>12</sup> each have approval for 3 trains, however none of the projects currently has sufficient reserves to support a third train (refer to section 3.6 for details on each projects gas reserves). BG Group has stated that it does not anticipate making a decision of a third train at QCLNG in the near future<sup>13</sup>.

### 2.1.3 Planned projects

A fourth two train LNG project planned for Curtis Island, that of Arrow Energy, was cancelled in January 2015<sup>14</sup>. Arrow is now officially trying to find the best monetisation option for its CSG reserves, which include discussions on collaboration opportunities. The most economic opportunities are likely to be supplying a third train at one of the three projects nearing completion or providing incremental gas for the existing trains.

A further option for Arrow gas that has re-emerged since the cancellation of the stand-alone Arrow project is the smaller project of LNG Limited. This 2 x 1.5 Mtpa project, initially proposed in 2007 and to be located at

<sup>9</sup> Origin Energy International Roadshow , September-October 2014

<sup>10</sup> Queensland Co-ordinator General Website

<sup>11</sup> Ibid

<sup>12</sup> GLNG Project Environmental Impact statement - Executive Summary.

<sup>13</sup> BG Group 2013 4th quarter & full year results transcript (4th Feb 2014)

<sup>14</sup>Shell shelves Arrow LNG project in Queensland. Brisbane Times January 30, 2015.

Fisherman's Landing, on the mainland opposite Curtis Island, held a Memorandum of Understanding (MoU) for Arrow gas but this was not converted to a full contract. LNG Ltd was unable to find alternative resources and turned its attention to the Magnolia LNG project in the US. However LNG Ltd has recently renewed its lease on the Fisherman's Landing site and its deadline for construction of the project has been extended by the Queensland Government to December 31 2017<sup>15</sup>. It is also noted that PetroChina, a partner in Arrow, holds shares in LNG Ltd and may favour sale of Arrow gas to such a project.

A number of other eastern Australian based LNG export projects have been put forward but none have access to demonstrated gas resources and none are considered likely to proceed in the period to 2020. Projects that may proceed after 2020 are unlikely to be at the planning stage yet.

#### 2.1.4 Gas resource availability

During the period from 2008 to 2011 when CSG reserves were growing rapidly (**Error! Reference source not found.**), based on published contingent and prospective resources it was projected that this growth rate could continue and may support considerably more than six trains. For example, forecasts prepared for the 2011 GSOO contemplated sufficient reserves to support further new trains being completed at the rate of one per year in the highest scenario, up to a total of 17 by 2027 .However since 2011 that reserves growth has slowed considerably, for a number of reasons, and prospects of further trains are far less certain:

- 1) During project construction development drilling of production wells has taken precedence over appraisal drilling to prove reserves.
- 2) Contingent CSG resource classification criteria have been tightened by the Society of Petroleum Engineers (SPE), with the result that 2C resources are now lower than previously.
- 3) Barriers to CSG development, in the form of Government moratoria and opposition by local activists, have intensified, particularly in NSW. Consequently in all NSW CSG Basins (the Clarence Morton, Gloucester, Gunnedah, Hunter and Sydney basins) some or all reserves have been declassified and development has slowed down or stopped.
- 4) Productivity of some fields appears to be below expectations
- 5) Exploration for CSG in the Galilee Basin has faltered after a number of poor drilling results
- 6) As a result of both the above and the shale gas success story in the US, the focus of exploration in eastern Australia has moved from CSG to shale gas, with interest mainly in the Cooper Basin because of its well-developed gas gathering and processing infrastructure.

However the shale industry is five to ten years away from demonstrating the economics and reserves necessary to support large scale production. In particular, the Australian industry does not yet support the competitive drilling and fracking sub-sector needed to reduce costs and at the \$8.30/GJ cost assumed in the 2013 GSOO LNG exports via Gladstone would not be economic.

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<sup>15</sup> Courier Mail 30 March 2015

### 2.1.5 Global LNG demand

LNG currently supplies approximately 9% of world demand for gas, with 20% supplied by international pipelines and the majority, 71%, supplied by domestic production and pipelines<sup>16</sup>. These market shares are largely determined by relative economics of supply, with shorter domestic pipelines having the lowest cost, followed by longer international pipelines and LNG, because of the high cost of liquefaction, typically being the most expensive.

The pre-dominant buyers of LNG have been countries lacking domestic gas resources and for which import pipelines are technically or commercially undesirable, such as Japan, Korea and Chinese Taipei, which currently account for 60% of global LNG demand. Secondary purchasers have been importing countries seeking additional security of supply, such as Europe generally and Singapore, and those supplementing domestic supply such as China and India. Security of supply is an attractive feature of LNG compared to import pipelines connecting to a single supplier.

LNG has been primarily supplied from gas resources that are surplus to a country's domestic market needs and/or otherwise stranded in locations where pipeline supply to markets is uneconomic. Current key suppliers by capacity are in the Middle East (Qatar and Oman), Africa (Nigeria, Algeria and Egypt), South East Asia (Indonesia and Malaysia), Australia and Trinidad.

LNG demand and supply capacity tend to move in step with one another. This is largely because the majority of LNG is supplied under long-term contracts between the buyer and seller which impose take-or-pay conditions on the buyers. The revenue from contracts underwrites the large capital investments by the sellers – without it debt funding would not be available. When buyers foresee demand growth they negotiate new contracts for new capacity and it is reasonable to assume that after that capacity has been constructed the demand for it will be there.

Disequilibria do arise due to unforeseen changes in demand and supply. Since 2012 for example, no new supply capacity has entered the market and some established capacity has been withdrawn<sup>17</sup>. At the same time Japanese demand for gas for generation increased due to the withdrawal of nuclear generators following the Fukushima incident. Such imbalances are managed via the LNG spot trade and as a result of the above Asian spot prices were high until very recently.

Thus in terms of projections, in the short term demand can be expected to match contracted supply from existing plants plus those under construction. At present this implies strong short term demand growth. In the longer term however LNG demand is subject to competition from domestic supply and international pipelines. The US provides an example of the former: up to 2005 and possibly later it was widely believed that the US was running out of gas resources and a number of LNG import terminals were planned. While these were delayed by environmental and other factors, shale gas production rose dramatically, to the extent that import terminals are converting to export terminals. China may well provide a future example of both forms of competition, as it is trying to develop its own shale gas resources and has committed to purchase large volumes of gas from Russia via a new pipeline.

In its recent Gas Market Report 2014, the Bureau of Resources and Energy Economics<sup>18</sup> presents a global LNG demand outlook to 2030 which reflects these considerations. Demand growth to 2020 is a strong 6.5% pa and demand reaches 370 Mt in 2020. Growth weakens to 1% in the decade to 2030 however, due to “higher indigenous production in most regions (especially of shale and unconventional gas) and increased imports by pipeline”.

<sup>16</sup> Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014.

<sup>17</sup> Egypt has withheld gas for its domestic market and Angola LNG has suffered technical failures.

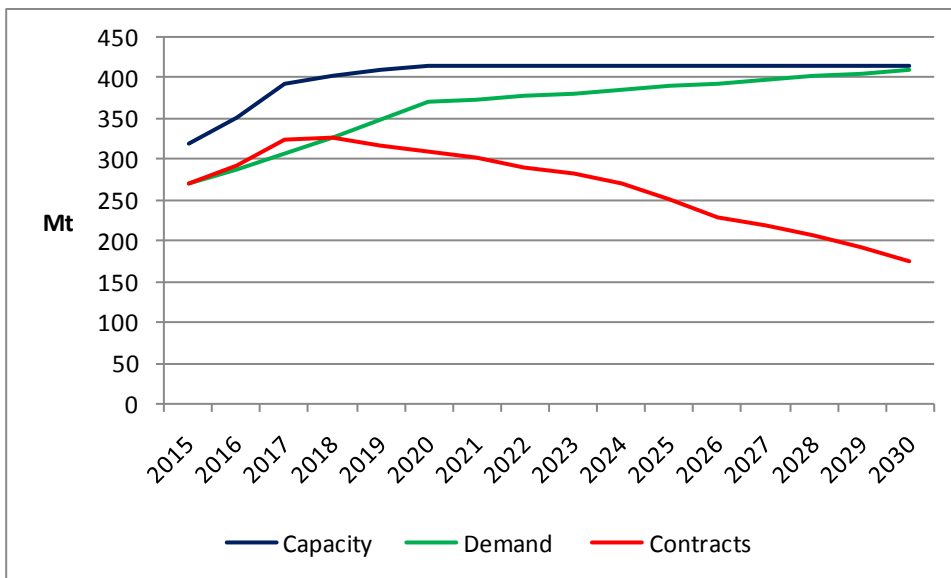
<sup>18</sup> Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014



This demand projection is compared with projections of liquefaction capacity and long-term LNG contracts in Figure 2-1, in which capacity means capacity currently operating or under construction and contracts means current long term contracts of more than 5 years duration when entered, for LNG supplied by plants operating or under construction. It is noted that some demand is met by short term or spot trades, some of which are direct sales by producers whereas others are diversions of contracts to other markets.

It goes without saying that before demand exceeds current contracts, new contracts will be entered or existing contracts will be extended. It is less clear when new capacity may be required but if the margin between capacity and demand in 2013 is to be maintained then by 2020 a further 24 Mt (5 to 6 trains) of new capacity would be required, with approximately one new train each year after that. More capacity will also be required to replace plants that are likely to be retired or operate below capacity, either due to their age or lack of gas feedstock. This outlook suggests there are some opportunities for further capacity to be constructed in Queensland or elsewhere in eastern Australia.

**Figure 2-1 LNG demand, contract and capacity projections**



Sources: Demand – BREE; Contracts – The LNG Industry 2013, GIIGNL; Capacity – GIIGNL and IGU World LNG Report 2014.

**2.1.6 Competition from other suppliers**

During the past five years Australia has represented a significant proportion of new LNG capacity that has started construction. As well as the 25 Mtpa capacity in Gladstone, 37 Mtpa capacity is under construction in Western Australia and the Northern Territory: Gorgon (15.6 Mtpa); Wheatstone (9 Mtpa); Ichthys (8.4 Mtpa); and Prelude (3.6 Mtpa). A total of 43 Mtpa is under construction elsewhere, principally in the US and Russia. Australian exports are scheduled to reach approximately 80 Mtpa by 2018, placing the country as the leading gas exporter, slightly ahead of current no.1 - Qatar on 77 Mtpa.

Reasons for Australian market dominance during this period include availability of gas resources, absence of export constraints, absence of a national oil and gas company with mandatory project participation, manageable regulatory systems and limited sovereign risk. These factors continue to be present, particularly in WA where the Browse and Scarborough projects have narrowly failed to reach committed status. However all the Gladstone projects and Gorgon have suffered significant cost overruns, in part because of their nature (Gorgon is on Barrow Island, a Class A nature reserve) and in part because of competition for construction resources among these projects and with other Australian resource projects such as iron ore.

In the 2014 Projections Jacobs estimated that future greenfield Australian LNG projects would cost 15% to 20% more than projects in the US, Canada and Mozambique. BREE has recently conducted a more detailed study of comparative long-run marginal costs and confirmed these estimates (Table 2-4). However BREE estimates that the costs of brownfield projects making use of existing liquefaction sites could reduce liquefaction costs by 30% to 40% and, in the case of eastern Australian CSG based projects, sharing pipeline infrastructure would also reduce upstream costs. This would reduce CSG project costs by approximately \$US2.50/mmbtu and make them more competitive with other new projects.

**Table 2-4 Comparisons of long-run marginal delivered costs of LNG to Japan (\$US/mmbtu, \$2012)**

Export Origin	Gas Production	Liquefaction	Shipping	Total Cost
Malaysia Borneo (Asia Pacific)	\$1.84	\$4.20	\$0.71	\$6.75
PNG (PNG LNG)	\$2.62	\$4.23	\$0.82	\$7.67
US Louisiana (Sabine Pass), shale				
low gas cost	\$3.36	\$2.36	\$2.27	\$8.00
medium gas cost	\$3.62	\$2.36	\$2.27	\$8.25
high gas cost	\$4.01	\$2.36	\$2.27	\$8.64
Indonesia East (Sengkang LNG)	\$3.67	\$4.80	\$0.68	\$9.15
Australia West (Gorgon)	\$3.70	\$5.64	\$0.84	\$10.18
Australia North (Ichthys)	\$4.16	\$6.00	\$0.70	\$10.86
Australia East (APLNG), CSG				
low gas cost	\$3.54	\$5.15	\$0.84	\$9.53
medium gas cost	\$5.72	\$5.15	\$0.84	\$11.71
high gas cost	\$8.22	\$5.15	\$0.84	\$14.21

Source: Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014

The list of current planned LNG projects reflects this lack of competitiveness of Australian projects, particularly the CSG resourced projects of which there are effectively none in planning.

**Table 2-5 LNG projects in planning**

Country	Project
Australia	Bonaparte LNG
	Browse FLNG
	Fisherman's Landing CSG LNG
	Scarborough LNG *
	Sunrise LNG *
Canada	Douglas Channel LNG
	Kitimat LNG
	LNG Canada
	Pacific Northwest LNG
Indonesia	Abadi FLNG
Nigeria	Brass LNG *
	Olokola LNG

Country	Project
PNG	Gulf LNG
Russia	Baltic LNG
	Shtokman LNG
	Vladivostok LNG
USA	Alaska South Central LNG
	Corpus Christi LNG
	Jordan Cove LNG
	Lake Charles LNG
	Oregon LNG

Source: [www.globallnginfo.com](http://www.globallnginfo.com)

Notes: 1) Projects marked \* have been in planning for a prolonged period and LGA considers they are unlikely to proceed in the near term. 2) East African projects have yet to enter the planning phase.

### 2.1.7 LNG pricing

LNG contract pricing in the East Asia region has for many years been oil linked through a formula such as:

$$\text{LNG price} = \alpha * \text{JCC} + \beta$$

In this formula the LNG price is expressed in \$US/mmbtu and JCC is the Japan Customs Cleared crude price, also nicknamed the Japan Crude Cocktail, expressed in \$US/bbl and linked to the Brent Crude price.  $\alpha$  and  $\beta$  are constants that are set during the contract negotiations and can only be varied periodically. The formula would also typically have a cap and a floor to protect buyer and seller from extreme JCC variations.

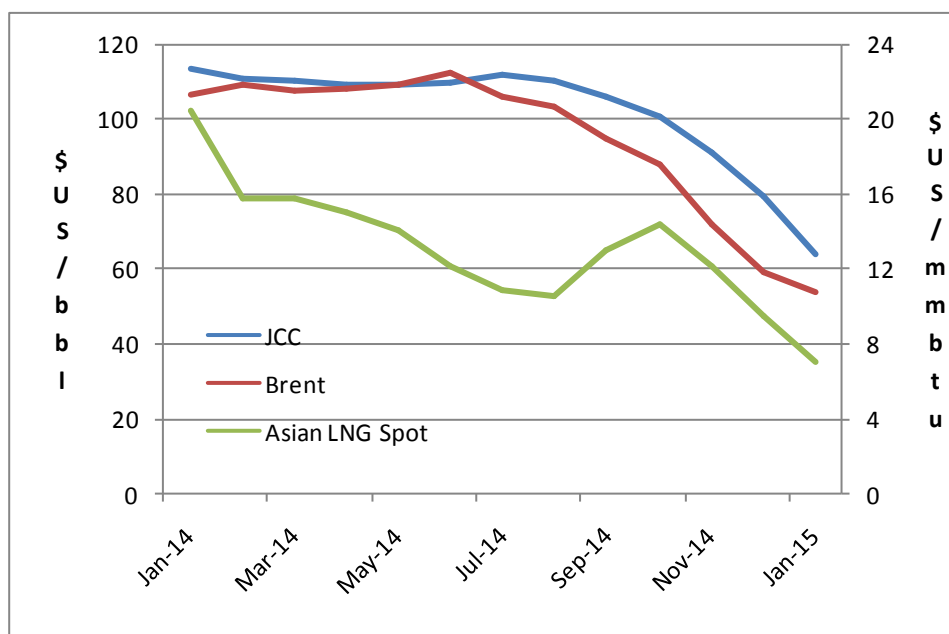
A value of the slope parameter  $\alpha$  of 0.172 indicates full energy equivalence of LNG with oil. It is understood that the Gladstone LNG projects have contracted at values in the range 0.12 to 0.155 and correspondingly low values of  $\beta$ . An average of slope of 0.14 is assumed, together with a constant of zero.

When the Gladstone contracts were negotiated the oil price was over \$US100/bbl hence the contract price was over \$US14/mmbtu, well in excess of the LRMC and generating returns above the cost of capital for the sellers. Recently however the oil price has fallen to below \$US60/bbl (Figure 2-2), at which the LNG contract price is just \$8.40/mmbtu, well below long-run costs and illustrating the high risks involved in oil indexed pricing. Asian spot LNG prices have also fallen, to about \$US7/mmbtu, indicating weakness in short-term demand.

At the time the contracts were negotiated the buyers had few alternative options but the US projects subsequently emerged with a different pricing model in which the LNG price is set at a constant (covering liquefaction and shipping) plus the US Henry Hub price of gas, with a 15% margin. This is a much lower risk pricing model, with prices expected to remain the band between \$US10/mmbtu and \$US12/mmbtu.

Thus at current oil prices the Gladstone LNG contract prices are highly competitive with the US price structure but not earning an adequate return on the investments made. If current oil prices persist, and it is generally expected that they will remain below \$100/bbl for a number of years, it is highly unlikely that any new high slope contracts will be entered. Future Gladstone contracts will therefore either have lower slopes or adopt the US model.

Figure 2-2 Falling oil and LNG prices<sup>19</sup>



## 2.2 Scenario selection

The following scenarios have been constructed in consideration of the above:

- 1) With the cancellation of the Arrow LNG project the prospects of further capacity being constructed in the short to medium term in eastern Australia are limited. The Base Scenario<sup>20</sup> should therefore feature just the six trains under construction. LGA considers that the most reasonable levels of production in this scenario are the current commitments indicated by the stakeholders, i.e. long term production at their contracted output levels. QCLNG’s “contracted” output is assumed to be 8 Mtpa, allowing a similar margin between contracts and capacity as the other two projects.
- 2) The Low Scenario must then be the six trains with lower production due to either buyers not wanting to take their full contract cargoes or due to gas supply shortfalls (refer to next section). Although current contract prices are low, Asian spot prices are lower which may lead to the first of these outcomes. A 15% reduction on contracted levels has been assumed, as this is viewed as likely to be consistent with LNG contract take-or-pay, which BREE has estimated at 85%<sup>21</sup>. It is noted that the QCLNG plant could operate at lower levels to fit in with broader BG Group production plans.

This scenario also incorporates delays to start-up, particularly of 2<sup>nd</sup> trains, and a slower ramp-up to plateau production.

It is noted that while the LNG projects are understood to be cash positive in the short run, even at current prices, continuation of these prices may make ongoing well development to maintain CSG output less economic.

<sup>19</sup>Sources: JCC – Japanese Ministry of Finance; Brent – Investing.com; LNG Spot – Timera-Energy.com

<sup>20</sup> LGA has used the term Base Scenario to denote the most likely outcomes. It is intended that this scenario should correspond to AEMO’s Planning or Medium scenarios.

<sup>21</sup> Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014

- 3) The High Scenario is designed to test the upper boundaries of feasible gas and electricity usage and assumes that a 3<sup>rd</sup> train (7<sup>th</sup> in total) is constructed on one of the three existing project sites on Curtis Island, to be supplied from Arrow's Surat Basin gas, which is considered to be sufficient for just a single train of 4 Mtpa capacity (section 3.6.1). It is possible that a similar project could be constructed on LNG Ltd.'s Fisherman's Landing site as an alternative 7<sup>th</sup> train.

Either of these options would require only a short pipeline to link the Surat production centre to one of the existing trunk pipelines plus compression of that pipeline. It is assumed that Arrow's Bowen Basin reserves, which would require an additional pipeline to Gladstone, are not developed for LNG.

This project is considered unlikely to be approved before 2017, since some recovery in oil prices is required and may have occurred by this time. Consequently it is projected to be in production no earlier than 2021. In this report the 7<sup>th</sup> train is referred to as the Arrow project.

It is also assumed that the other six trains ultimately operate at full capacity rather than at contracted capacity, after a period of plant debottlenecking. The transition point to full capacity is set at the start of 2020 for all three projects.

The High Scenario could involve further trains supplied by shale gas but the economics have yet to be demonstrated and the timeframe is highly uncertain and this possibility has not been considered.

Other scenarios are also feasible, including a mixed low/high scenario in which LNG ramp up is slower than in the Base Scenario but production ultimately reaches full capacity.

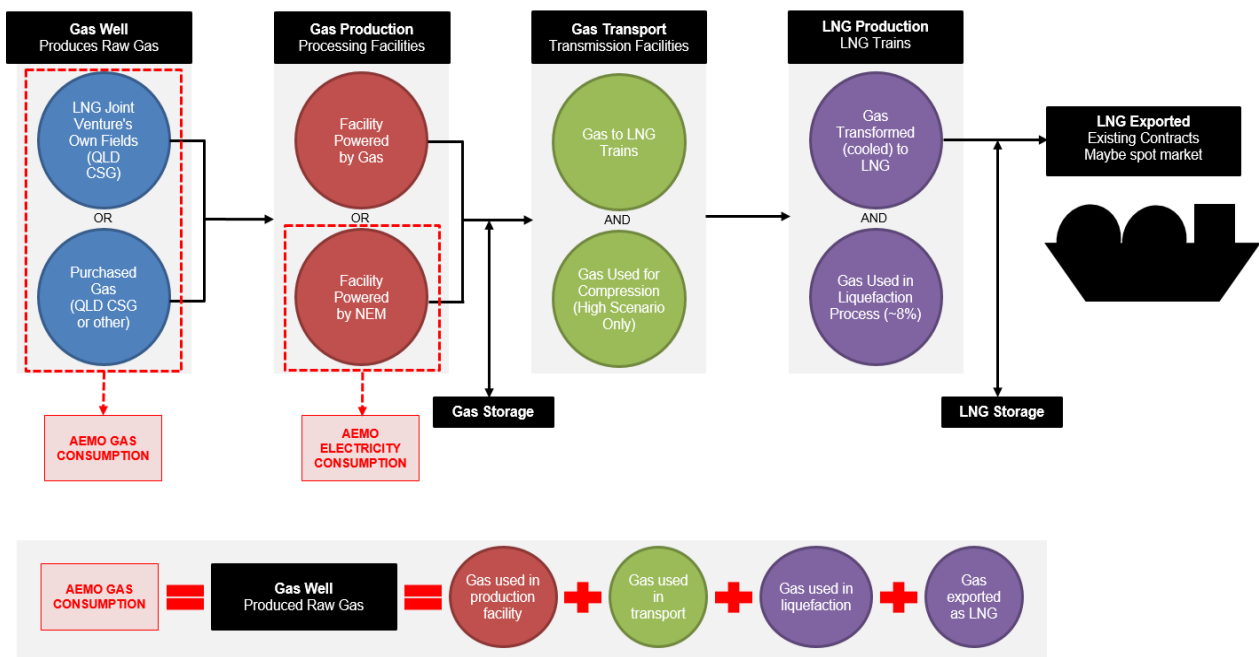
LGA considers the above scenarios to be consistent with the AEMO scenario definitions set out in section 2.1.1.

### 3. Methodology

#### 3.1 Overview

The gas supply chain from wellhead to export and the relevant components of each component of the chain are illustrated in Figure 3-1. It is noted that this representation of the supply chain excludes: the shipping component, because it is understood the contracted export quantities are free on board (FoB) volumes; and energy used in drilling wells, which is mainly diesel rather than gas or electricity.

Figure 3-1 The LNG supply chain



Source: AEMO

The gas and electricity usage projections in this report have been derived using a similar methodology to that applied by Jacobs to prepare the 2014 projections. The projection logic models the supply chain backwards, from right to left in the above diagram. Starting with the targeted export volumes, which are relatively well known, the energy used in LNG production or liquefaction is calculated first. This determines the quantities of gas that must be transported to the liquefaction plants and the energy used in transportation. The total gas transported and used in transportation in turn sets the quantities of gas required to be delivered from the gas processing plants, the energy used in those plants and at the gas wellheads.

The calculations are not quite symmetric, in that where gas is used at any point in the chain, the volume used is added to the upstream requirement and leads to slightly increased usage upstream. However where electricity is used, no assumptions are made regarding the ultimate energy source and consequently there are no multiplier effects as there are for gas.

The above methodology assumes that there is very little energy usage prior to actual LNG production. However it is well known that CSG wells cannot be brought on-line instantaneously and instead have to be ramped up to full production. The ramp-gas produced is generally used in the domestic market or by other LNG plants already on-line and is considered to have substituted for other gas that could have met this demand<sup>22</sup>. Consequently it is

<sup>22</sup>The ramp-gas may be sold at a low price that affects the level of domestic demand but this factor is not considered here.

not considered part of gas usage for LNG. However where ramp-gas is produced from new wells in a new plant using electric grid powered compression, it creates new electricity demand that is substituting for gas that would have been used to compress the gas that was substituted by the ramp gas. The effects of ramp gas have been taken into account in the 2015 projections.

The sub-models used to estimate energy usage at each stage of the supply chain are straightforward and derived from: public information, including the reports on the 2014 and 2013 projections; AEMO information on gas and electricity consumption related to the LNG projects, The latter information is available for the first time in 2015.

The overall model operates on the basis that the input export demand will be met and is not constrained by gas supply capacity. Implications of potential supply constraints are investigated by varying the demand, as in the Low Scenario. It is noted that the possibility of supply constraints continues to occupy industry commentators prior to the major ramp up in gas and LNG production scheduled for the second half of calendar 2015.

The underlying model is based on quarterly intervals, to achieve more precision than achievable with annual intervals but retaining more computational manageability than a monthly model. Annual and six-monthly results are simple summations of quarterly results, while monthly results have been derived from quarterly ones using the algorithms described in section 0.

**Table 3-1 The LNG supply chain**

<b>Process</b>	<b>Energy use</b>	<b>Gas volume</b>	<b>Grid supplied electricity</b>
<b>Export</b>	Nil, export volumes assumed to be on an FoB basis	Gas exported	Nil
<b>Liquefaction</b>	Direct drive compressors, electrical power	Gas delivered by pipeline	Possible but not selected for current Gladstone projects <sup>23</sup>
<b>Gas Transmission</b>	Mid-point compression	Gas delivered by processing plant	Possible <sup>24</sup>
<b>Gas Production</b>	Compression, auxiliaries	Gas extracted from reservoirs	A selected option for all projects

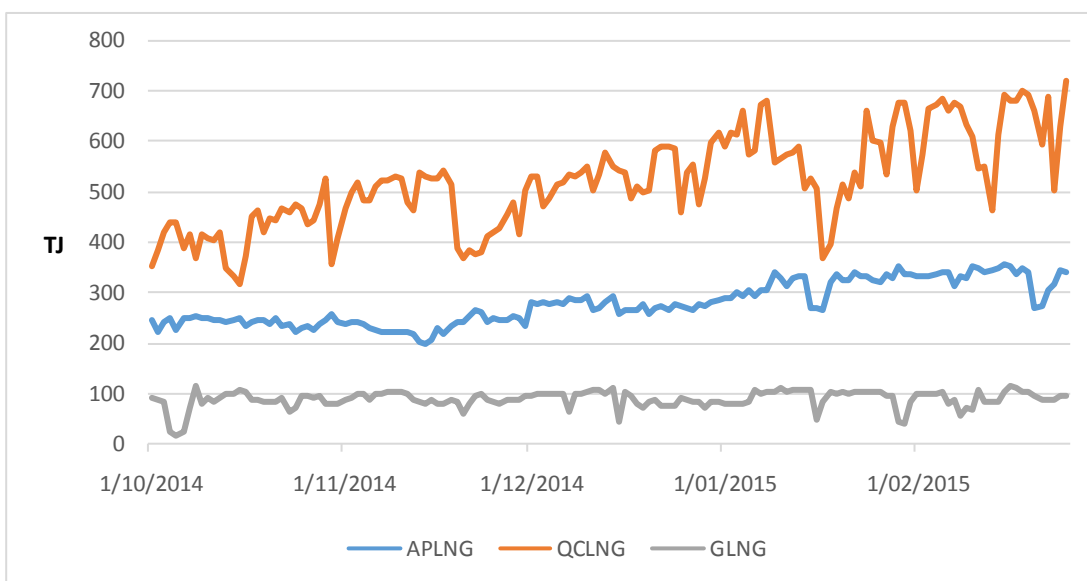
<sup>23</sup> Future Curtis Island LNG facilities could be connected to the NEM via a cable connection

<sup>24</sup> The QCLNG and APLNG pipelines are sufficiently proximate to the Queensland EHV electricity grid for grid electrically driven compression to be credible. The mid-point of the GLNG pipeline is not close to the EHV electricity grid.

**3.1.1 Historical data**

QCLNG shipped the first LNG from Gladstone in the Methane Rita Andrea on the 5<sup>th</sup> January 2015, having commenced liquefaction in late December 2014. Since then a further 6 shipments were made up to the end of February, carrying an estimated 0.5 MT of LNG, which represents approximately 75% utilisation of Train 1’s target rate of production. This level of production is consistent with the Base Scenario in the 2014 Projections, which assumed 50% utilisation in the December quarter of 2014 and 75% utilisation in the March Quarter of 2015. QCLNG’s production of CSG prior to and after first LNG is shown in Figure 3-2. This clearly shows a ramp up of production prior to and during December 2014 and several reductions in production since first LNG, consistent with estimated levels of LNG production.

**Figure 3-2 Daily CSG production**



Source: AEMO Gas Bulletin Board

Unfortunately, precise estimates of gas used in LNG production cannot be derived from the QCLNG CSG production figures, owing to the unknown quantities supplied to the domestic market and the unknown quantities of third party gas used by QCLNG for LNG production. Accurate estimates of gas used in LNG production could be derived from LNG transmission pipeline gas flows; however these are not yet available on the Gas Bulletin Board or from any other sources.

Use of the production data to estimate ramp gas production is described in section 3.6.3 and combined use of the production data and electricity usage by the gas processing plants is discussed in section 3.6.4.

**3.2 Gas exported**

The assumed plateau export levels in each scenario are summarised in Table 3-2. The Base Scenario export levels are set at the levels of the foundation LNG contracts. Corresponding to the 20 year terms of the contracts that form the basis of the Base Scenario, the exports in each scenario can be assumed to extend to at least 2035. The LNG plants have serviceable lives well in excess of 20 years and with low marginal costs are likely to remain competitive in the global LNG market provided competitively priced feed-gas is available. Each scenario is therefore assumed to extend to 2040.



**Table 3-2 Plateau export levels (Mtpa)**

<b>Scenario</b>	<b>QCLNG</b>	<b>GLNG</b>	<b>APLNG</b>	<b>Arrow</b>
<b>High</b>	8.5	7.8	9.0	4.2
<b>Base</b>	8.0	7.2	8.6	Not applicable
<b>Low</b>	6.8	6.1	7.3	Not applicable

Start-up and ramp timing assumptions are presented in Table 3-3:

- The Base Scenario is LGA’s interpretation of most recent timing statements by projects:
  - QCLNG<sup>25</sup>: Train 1 (T1) started in December 2014 and made 6 shipments in January and February [Quarter 1 (Q1)] 2015; T1 on plateau in Q2 CY 2015; T2 start up Q3 CY 2015; plant plateau 8 Mtpa mid CY 2016
  - GLNG<sup>26</sup>: T1 start up in H2 CY 2015, ramp-up over 3-6 months; T2 ready by the end of H2 CY 2015; ramp up over 2-3 years
  - APLNG<sup>27</sup>: T1 start up mid-CY 2015; T2 start up end CY 2015; full production both trains end FY 2016
- High Scenario: For all projects acceleration of start-up of either train seems unlikely. Some acceleration of T2 ramp up is assumed. For the High Scenario “Plateau” means the contract level with the increase to full plant capacity occurring in 2020.
- Low Scenario: First LNG and plateau are delayed relative to Base Scenario for all elements except QCLNG T1. This would be consistent with minor technical problems prior to or during start-up.

<sup>25</sup> BG Group 2014 4th quarter & full year results presentation and transcript (3<sup>rd</sup> Feb 2015)

<sup>26</sup> Santos 2014 Investor Seminar (26th Nov 2014)

<sup>27</sup> ORG LNG Site Tour 30-31 Oct 2014

**Table 3-3 Start-up and ramp-up timing**

	QCLNG				GLNG				APLNG			
	T1		T2		T1		T2		T1		T2	
	Actual Start	Plat	Start	Plat	Start	Plat	Start	Plat	Start	Plat	Start	Plat
<b>High</b>	Q4 14	Q2 15	Q3 15	Q1 16	Q3 15	Q1 16	Q1 16	Q3 17	Q3 15	Q1 16	Q1 16	Q2 16
<b>Base</b>	Q4 14	Q2 15	Q3 15	Q2 16	Q3 15	Q1 16	Q1 16	Q2 18	Q3 15	Q2 16	Q1 16	Q3 16
<b>Low</b>	Q4 14	Q3 15	Q4 15	Q1 17	Q4 15	Q2 16	Q3 16	Q1 19	Q4 15	Q2 16	Q3 16	Q2 17

Notes: T1 = Train 1 first gas exported; T2 = Train 2 first gas exported; Plat = Plateau production reached for each train; Q1 = first quarter of the calendar year etc.

Initial production in LNG plants during their commissioning phase tends to be variable, with periods of production at full capacity alternating with periods of downtime for scheduled maintenance and process tuning. To capture this in the projections the first quarter of production for each train is assumed to average 50% of contract level and thereafter production ramps up to the plateau level. This is reasonably consistent with QCLNG’s output during Q1 2015 which is estimated to be 30 PJ (based on AEMO Gas Bulletin Board and shipping information), compared to plateau contracts of 54 PJ per quarter per train. It is assumed that gas supply could be ramped up to match these scenarios.

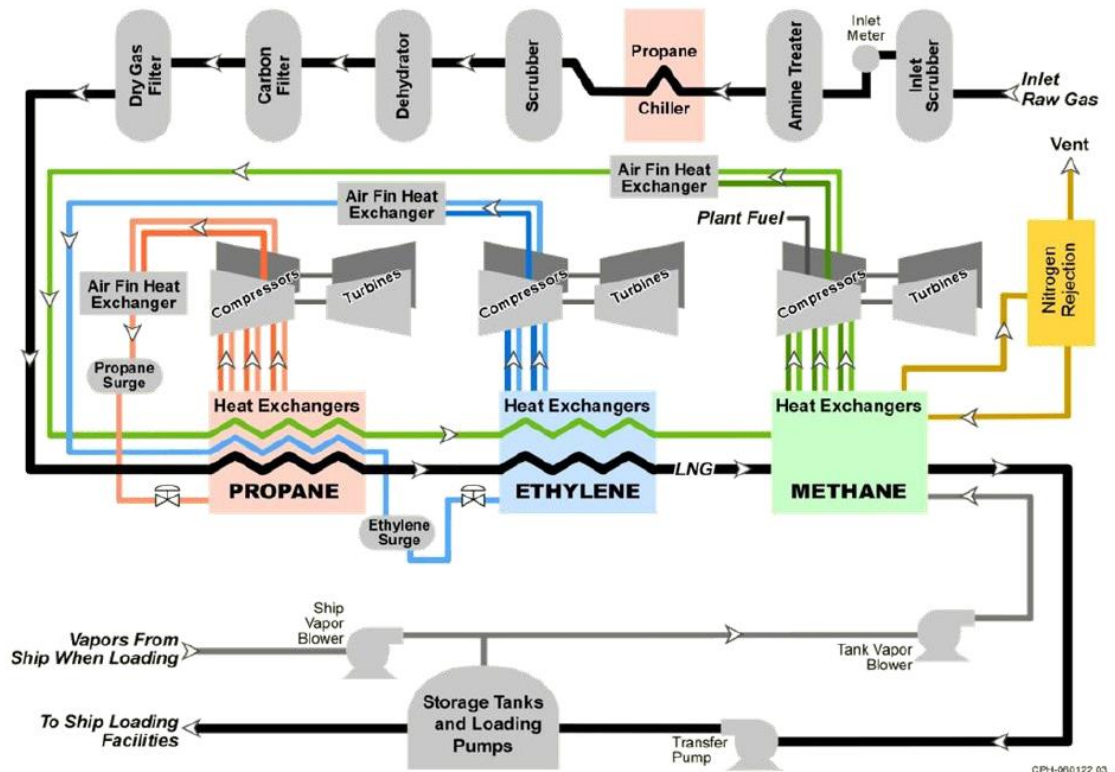
### 3.3 Energy used in LNG production (liquefaction)

#### 3.3.1 Energy sources

In the 2014 Projections of Gas and Electricity used in LNG Jacobs noted that most LNG plants globally are fully gas powered owing to their remoteness from electricity grids. Although the Gladstone plants could be grid connected, all are being built to the same Conoco Philips Optimised Cascade design by Bechtel and all plants of that design built to date have been gas fuelled. A diagram presented by APLNG (Figure 3-3) indicates that the same applies to the Gladstone plants. Consequently Jacobs considered that the Gladstone plants would be gas fuelled and use no grid electricity and no subsequent evidence contradicts this assumption.

Figure 3-3 APLNG Liquefaction plant Outline

Liquefaction of natural gas is an established technology, with project design based on the Darwin LNG project which has operated since 2006



Source: APLNG Project Overview, 20 Sept 2011

### 3.3.2 Testing gas usage

Gas is introduced to the liquefaction plants some 6 to 9 months before first LNG production, to enable all elements of the plant to be thoroughly tested and for the storage tanks to be cooled down to -16°C. For the 2014 Projections Jacobs estimated that an average of 10 TJ/d would be used during testing and this figure has been retained.

### 3.3.3 Liquefaction gas usage

In the 2014 Projections Jacobs estimated that 8% of gas input to the Gladstone plants would be used as fuel. As the QCLNG plant commenced operation in December 2014 it is desirable to test this estimate against actual outcomes but at this point in time the relevant data is not available.

The Jacobs figure is however supported by estimates prepared by Clough for LNG projects using conventional gas<sup>28</sup>. Clough estimates that 7% to 9% of input gas would be required for fuel gas, depending upon the liquefaction technology employed, with a central estimate of 8%. As 5% of the input gas is C3+ hydrocarbons and 2% is CO<sub>2</sub>, only 85% is liquefied, compared to 92% in Jacobs assumptions. Correcting for this difference between conventional gas and CSG, the Clough estimate is equivalent to 8.66% fuel usage for CSG fuelled

<sup>28</sup>Rules of thumb for screening LNG developments. Clough presentation to IE Perth, 2 October 2012.

plants. However the Clough plant also includes slightly more gas processing than the Gladstone plants, since there is no separate upstream processing in the Clough design. The additional energy use is not identifiable but LGA considers that the Clough figure supports use of 8% as the best estimate of fuel usage for liquefaction.

There may be some variation in fuel requirements between the three plants owing to detail design differences and differences in their transmission delivery pressures. These variations are not accounted for in these projections.

### 3.4 Energy used in gas transmission

Each of the three LNG projects has constructed a transmission pipeline to convey gas from their CSG processing plants in the Surat and Bowen basins to Gladstone. The pipeline routes are depicted in Figure 3-4 and major parameters are presented in Table 3-4. Each project also has a network of smaller diameter pipelines connecting the gas processing plants (GPPs) with the export pipelines and operating at the same pressures. The pipelines are interconnected with one another at a number of locations to facilitate operational and commercial exchanges of gas.

Figure 3-4 LNG Pipelines Map



Source: 2013 GSOO, AEMO, 29 November 2013.

**Table 3-4 LNG export pipeline parameters**

	<b>QCLNG</b>	<b>GLNG<sup>29</sup></b>	<b>APLNG<sup>30</sup></b>
<b>Length Main Export PL (km)</b>	334	420	362
<b>Internal Diameter (mm)<sup>31</sup></b>	1,040	1,040	1,050
<b>Maximum Operating Pressure (kPa)</b>	10,200	10,200	13,500
<b>Capacity without compression (TJ/d)</b>	1,510 <sup>32</sup>	1,350 <sup>33</sup>	1,560 <sup>34</sup>

LGA has assessed the energy usage in the pipelines under the following assumptions:

- It is assumed that each project transports its own gas requirements for liquefaction
- The gas is compressed up to operating pressure at the GPPs, or elsewhere for third party gas. The energy used at GPPs is part of processing energy use
- The uncompressed capacities of the pipelines (Table 3-4) are each sufficient to transport the peak gas requirements for two trains in all scenarios.
- Further compression will only be required by a pipeline transporting gas for a third train in the High Scenario. The quantum of midpoint compression required for this pipeline has been estimated using an LGA gas flow model. The model computes the pressure loss along the pipeline at any given flow rate, using steady state flow pressure loss calculations. If the pressure at the pipeline delivery point falls below the target pressure for delivery into the LNG plants, assumed to be 5,000 kPa, then further compression is required at an intermediate point along the pipeline. The amount of compression in MW required to lift delivery point pressure to the required level is computed in a similar way and fuel usage for compression is computed from the electricity requirement.

In the High Scenario whichever pipeline is used to supply the 7<sup>th</sup> train will be carrying gas for three trains, assuming that the Arrow gas GPPs providing gas for this train are connected to one pipeline only. In this case the flow modelling suggests that mid-line compression is required in this pipeline.

As with the liquefaction plant, this compression can be driven by a gas turbine or electrically, via local generation or grid connection. The latter is available at low cost near the midpoints of the APLNG and QCLNG pipelines but not at the midpoint of the GLNG pipeline, which lies further west. To standardise the calculation of compression energy independent of the pipeline used by the Arrow project we have therefore assumed that pipeline compression is gas driven.

<sup>29</sup>GLNG Gas Transmission Pipeline Description

<sup>30</sup> "Constructing the pipeline", available on [www.aplng.com.au](http://www.aplng.com.au)

<sup>31</sup> All pipes are stated to be 42 inches in diameter. The stated diameters in mm vary.

<sup>32</sup>Acquisition of the QCLNG Pipeline and Entitlement Offer, 10 December 2014

<sup>33</sup>LGA estimate

<sup>34</sup>Constructing the Pipeline, APLNG, December 2012

Estimated gas compression usage due to the Arrow project varies depending on which pipeline transports the Arrow gas, because of the different operating pressures. For 800 TJ/d load the estimate is 28 TJ/d (3.5% of load) for the APLNG pipeline and 41 TJ/d (5.2% of load) for the QCLNG and GLNG pipelines and the 5.2% figure has been adopted for the projections. This is very similar to the 5.3% figure used by Jacobs for the 2014 Projections. This factor is applied at all Arrow project loads. In the modelling and reporting all intermediate compression usage is allocated to the Arrow project. The project also uses energy in liquefaction and upstream in similar proportions to the other projects.

### **3.5 Energy used in gas storage**

Underground gas storage is to be used by two of the LNG projects, QCLNG and GLNG, to augment gas supply during initial ramp-up phases and to assist in gas management during LNG plant shutdowns. Energy is used to compress gas into the underground storage field and again to extract it.

The AGL storage at the Silver Springs field (contracted to QCLNG) has relatively limited injection and withdrawal rates (approximately 40 TJ/d for both) compared to QCLNG daily gas requirements (1,300 TJ/d). Santos Roma underground storage (developed for GLNG), while of greater capacity (75 TJ/d withdrawal), makes up less than 6% of GLNG's daily gas requirements (1,200 TJ/d). In view of this and because the storage contributions are likely to be small under steady state operation, LGA determined to exclude storage from the modelling. This will result in a minor understatement of total energy use but the understatement is likely to be less than uncertainty in other factors such as liquefaction use.

### **3.6 Energy used in gas supply**

#### **3.6.1 Gas supply**

CSG resources required to support an 8 Mtpa project for 20 years, including gas used in production and ramp up/down gas, are estimated to be approximately 12,000 PJ<sup>35</sup>. The principal source of these resources for each project will be their equity reserves in Queensland CSG (Table 3-5). Owing to joint ownership of some fields, some of this gas will be developed and operated by other projects and to access this gas the projects have entered sales and purchase contracts with one another. Two of the projects, QCLNG and GLNG, have also entered contracts with third parties for gas from other sources, to assist project start-up and to make up for current shortfalls in reserves (Table 3-6). In addition to the reserves shown in Table 3-5 each project has additional CSG and other gas resources than can be developed over the life of their projects and GLNG has contracted approximately 2,000 PJ from third parties.

All three projects recorded increases in gas reserves between June 30 2013, the date of reserves estimates in the 2014 Projections, and June 30 2014.

<sup>35</sup> Approximately 9,500 PJ for 20 years production plus 2,500 PJ for ramp up/down. Ramp down is the minimum reserves required to support production of 475 PJ in the 20<sup>th</sup> year.

**Table 3-5 LNG project equity and operated Queensland CSG reserves as at 30 June 2014 (PJ)**

	Equity	Operated
<b>QCLNG</b>	11,257	12,953
<b>GLNG</b>	5,562	6,490
<b>APLNG</b>	14,443	11,850
<b>Arrow</b>	8,167	9,475
<b>Others</b>	2,592	1,252
<b>Total</b>	42,020	42,020

Source: Queensland Department of Natural Resources and Mines

**Table 3-6 LNG project contracts with third party suppliers**

<b>Seller</b>	<b>Operator</b>	<b>Buyer</b>	<b>Source</b>	<b>Delivery Point</b>	<b>Term (years)</b>	<b>Annual Volume (PJ)</b>
APLNG	QCLNG	QCLNG	Surat CSG	Field	20	95 falling to 25 after 2016
Santos	Santos	GLNG	Cooper primarily	Wallumbilla?	15	50
AGL	QCLNG	QCLNG	Surat CSG	Field	3	25
Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	10	36.5
Origin	Unknown	QCLNG	OE Portfolio	Wallumbilla	2	15
Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	5	20 <sup>36</sup>
Stanwell	Unknown	GLNG?	Wallumbilla?	Wallumbilla?	3	10
AGL	QCLNG?	GLNG	Surat CSG	Wallumbilla?	7	15
Meridian JV	Westside	GLNG	Bowen CSG	GLNG Pipeline	20	24

Sources: Company media statements. A question mark indicates that the relevant information has not been published and that the value in the table is the best estimate.

Complementary to the first contract, it has been assumed that APLNG will take 70 PJ of its equity share in the QCLNG operated fields, at the time it reaches plateau LNG production levels in 2016. There is also an arrangement between GLNG and APLNG for GLNG to take approximately 12 PJ pa of equity gas at Combabula.

<sup>36</sup>The annual volume may be doubled at Origin's option.

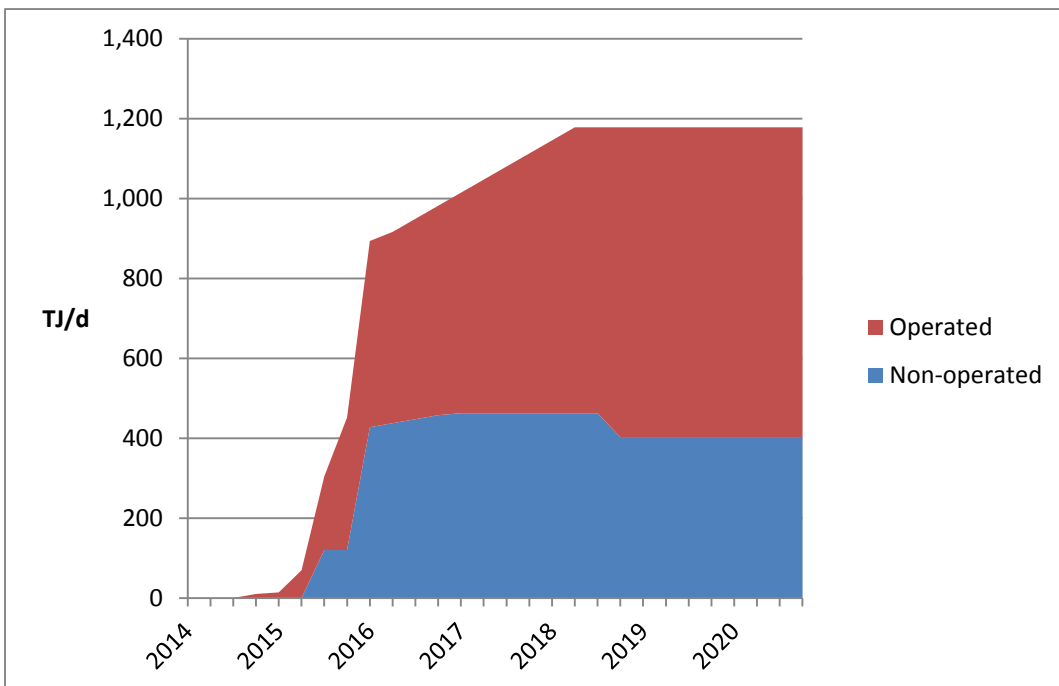
With regard to the additional train(s) in the High Scenario, Arrow’s equity reserves are currently sufficient for up to 6 Mtpa of liquefaction capacity. Moreover, approximately 2,400 PJ are in the northern Bowen Basin and would require a new pipeline to Gladstone, making them a higher cost option than the Surat Reserves that could access an existing pipeline. LGA therefore considers that the incremental LNG capacity supported by Arrow’s reserves in the High Scenario is effectively limited to about 4 Mtpa.

**3.6.2 Supply model**

For each LNG project, the contracts are separated into “operated” (contracts 1 and 3 in Table 3-6) and “non-operated” (all other contracts). The non-operated contracts are assumed to be used to their maximum subject to the LNG plant’s gas requirements, because it is reasonable to assume that the contracts all have high take-or-pay provisions. The operated gas requirement is then the LNG plant requirements, less the relevant non-operated contract volume, plus supply obligations to other projects. It is also assumed that contracts are not recontracted on termination but are replaced by additional equity gas. Figure 3-5 illustrates the application of this approach to GLNG in the Base Scenario.

The operated gas requirement must be supplied from the projects’ CSG fields. None of the projects has indicated publicly how supply will be drawn from fields and we have therefore based supply from each group of fields on their estimated capacities and timing. Application of this approach to APLNG is illustrated in **Error! eference source not found..** It is noted that these allocations are approximate in the short-term as the estimated capacities allow for more to be sourced from each group and will inevitably be incorrect in the long term because production in the first developed wells will decline and be replaced by new wells and new fields.

**Figure 3-5 GLNG Base Scenario gas allocation to operated and non-operated – average daily supply**





### 3.6.3 Ramp gas

Prior to producing LNG each project must ensure that its gas supply is available in the correct volumes when the LNG plant is ready to be commissioned and then to produce LNG. Unlike conventional gas fields, which once completed can be shut in and turned on just in time for production, CSG fields need to be dewatered and can then only be partially turned down. This means that CSG must be “ramped up” and produce gas in advance of the LNG plant requiring it.

Ramp gas can either be sold to another user or flared if no other users can be found. Given the relatively small volumes of ramp gas associated with the start-up of QCLNG, and similar projections for GLNG and APLNG, it is assumed that ramp gas will find domestic buyers who can arrange for their normal supply to be reduced. This occurred with QCLNG ramp gas in the second half of 2014, when Origin Energy purchased 28 PJ of ramp gas at relatively low prices<sup>37</sup>.

Under this assumption, ramp gas is substituting for other gas and does not represent additional gas demand. However ramp gas production at a grid-powered GPP does represent additional electricity demand and a corresponding loss of gas demand used in production of the substituted gas. This is the major reason for projecting ramp gas volumes.

A number of sources have been used to model ramp gas volumes:

- QCLNG actual volumes produced (sourced from the Gas Bulletin Board), less estimated contract sales
- A ramp gas chart presented by Origin Energy on behalf of APLNG (Figure 3-6).
- Statements by the project operators regarding the turndown they can achieve with their wells. APLNG is depicted as approximately 25% for Condabri<sup>38</sup> and GLNG suggests very high turndown for Fairview<sup>39</sup>.

The QCLNG chart shows gas production capacity for LNG increasing approximately linearly from one year before Train 1 starts production in mid-2015 until approximately the start of Train 2 production at the end of 2015. Actual production is then defined by the maximum of capacity \* turndown and the operated gas required for LNG. A model using this logic has been used to estimate ramp gas production for the three projects, with flexibility to deal with each scenario separately.

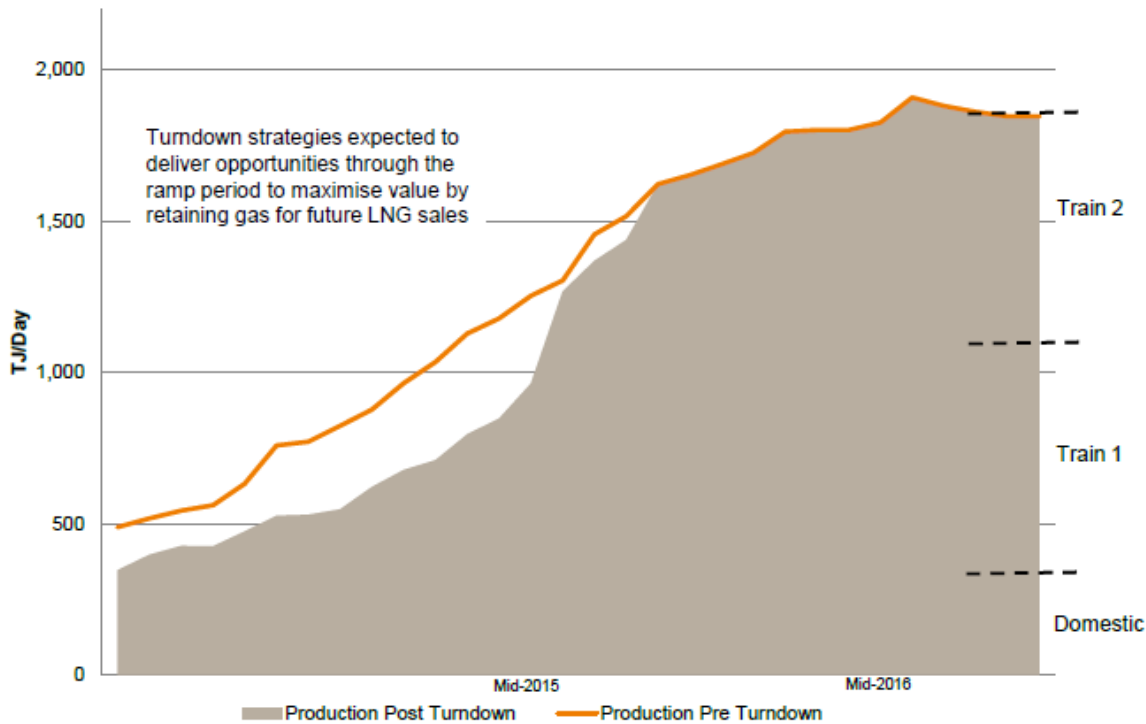
<sup>37</sup>2015 Half Year Results Announcement, Origin Energy, 19 February 2015

<sup>38</sup>Ibid

<sup>39</sup>GLNG Investor Visit June 2014.

Figure 3-6 APLNG gas production ramp up

**APLNG is on track for first LNG in mid-2015...**

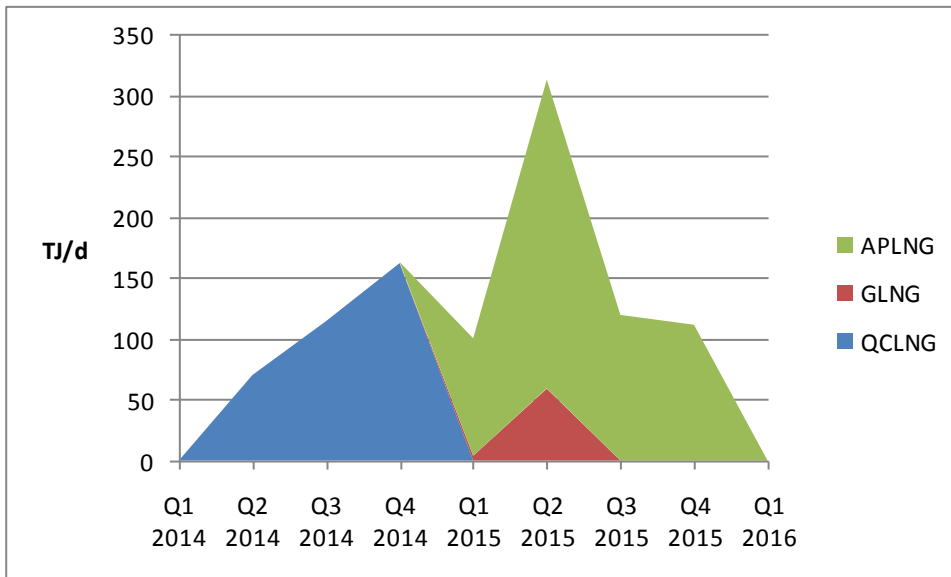


**... with full production expected from both trains by the end of FY2016**

Source: Origin Australia Pacific LNG Site Tour, 30-31 October 2014

Base scenario ramp gas projections are illustrated in Figure 3-7. Differences between the ramp gas volumes for the three projects are due to the assumption of different turndowns and the greater reliance of QCLNG and APLNG on operated gas.

Figure 3-7 Ramp gas projections for the Base Scenario



### 3.6.4 Gas field and processing plant energy usage

#### 3.6.4.1 Operated gas

The primary energy requirements are for field and plant gas compression, with lower requirements for auxiliaries including water pumping and desalination. All of the LNG projects are to have electric drive compressors for all new developments, which will be electricity-grid connected at both field and processing plant levels<sup>40</sup>. For QCLNG connection appears to be on schedule for LNG start-up but timing of some GLNG and APLNG connections appear to be after LNG Start up.

At Fairview GLNG has installed gas turbines, presumably as a temporary measure - it is estimated that grid connection will occur in 2016 and it is assumed that Fairview will be powered by the local GTs using GLNG gas until Q4 2015 inclusive. On 28<sup>th</sup> May 2014 the *Energy News Bulletin* reported that gas engine distributor Clarke Energy had been selected to provide APLNG with nineteen 3 MW gas engines at APLNGs Reedy Creek and Eurombah Creek CPPs. It is assumed that the gas engines will provide electricity to the CPPs until they are connected to the electricity grid, which is estimate to be from the beginning of 2017.

Existing plants are gas driven and are assumed to remain so. To determine the energy used in gas supply we have disaggregated the supply to the level necessary to capture gas vs. electric compression and the latter are disaggregated by Powerlink grid connection point.

Aggregate energy usage for compression and auxiliaries (gas and electric driven) has been estimated using a combination of: public project information (environmental impact statements); historical CSG plant usage figures published by the Queensland Department of Natural Resources and Mines (for gas usage only) and correlations between new CSG plant usage and electricity consumption figures provided by AEMO (for electricity usage only). The breakup of energy consumption between field, processing plant and auxiliary uses is based on estimates prepared by Jacobs for the 2014 projections.

<sup>40</sup>Powerlink Queensland Annual Planning Report 2013.

The energy usage figures for gas-driven plant in Table 3-7 are averages based on two years data from July 2012 to June 2014, the most recently available data. The values are reasonably consistent across the periods reported and reasons for the differences from company to company are not known. GLNG, for which gas usage figures are not provided, the Jacobs estimate of 6.4% is used. On average these revised estimates are slightly lower than the 6.4% estimated by Jacobs for the 2014 Projections and absent other changes to modelling or parameters, would lead to lower gas usage projections.

For energy usage from electrically driven plant AEMO has provided LGA with actual electricity usage data from three gas fields with grid powered compression for analysis: QCLNG’s Ruby Jo and Bellevue; and APLNG’s Condabri. This data is confidential but the usage estimates are slightly higher than the 2.4% estimated by Jacobs for the 2014 Projections and absent other changes to modelling or parameters, would lead to higher electricity usage projections.

**Table 3-7 Energy used in gas processing (% of net gas energy produced)**

	<b>QCLNG</b>	<b>GLNG</b>	<b>APLNG</b>	<b>Average</b>
Gas driven plant	5.0%	6.4%	6.5%	6.0%
Electricity driven plant	Confidential	Confidential	Confidential	Confidential

Sources: Queensland Department of Natural Resources and Mines, AEMO. The AEMO electricity data is not in the public domain and the resulting parameters are therefore confidential.

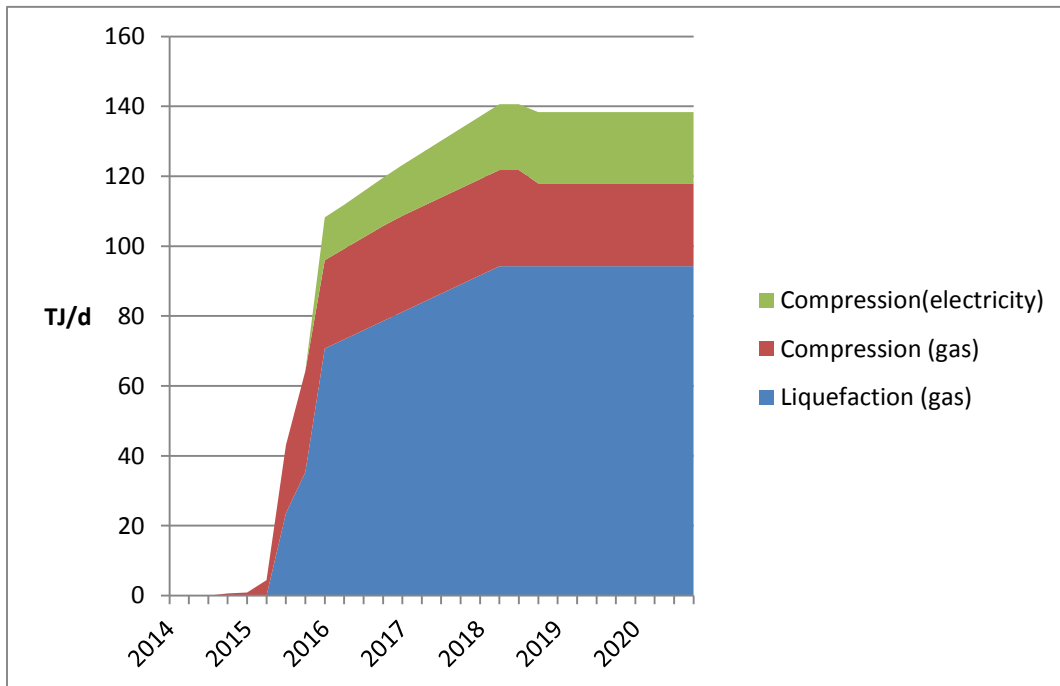
### **3.6.4.2 Non-operated gas**

The sources of non-operated gas are not known precisely though it is known that some is sourced from processing plants that cannot connect to the NEM, such as the Moomba and Ballera plants in the Cooper Basin. Consequently it has been assumed that all non-operated gas is non-grid connected and gas driven, with gas requirements set at 6.4% of net production, as for GLNG above.

### **3.6.5 Total energy usage**

The total Base Scenario energy usage projection for GLNG is shown in Figure 3-8. The total usage falls at the end of 2019 owing to a switch from gas to electrically driven compression, reflecting the lower energy requirement of electric compression.

**Figure 3-8 GLNG Base Scenario total energy usage**



### 3.7 Estimates of peak gas and electricity demand

When the LNG plants reach their operational plateau levels of production it should be possible to estimate peak load factors from their actual gas and electricity usage patterns. Until such time LGA considers that the Jacobs load factor estimates used in the 2014 projections remain appropriate. These are:

Gas production: 95% load factor

Electricity demand: 90% load factor.

### 3.8 Sensitivity of gas and electricity demand to gas and electricity prices

#### 3.8.1 Gas demand

Gas demand for LNG production is largely determined by the interplay of international prices which themselves influence domestic gas prices, rather than the reverse. The study methodology assumes that exports and the associated gas and electricity usage are not directly impacted by domestic price considerations.

High spot LNG prices reflect high demand and tight supply. These conditions would provide both the opportunity and incentive for the Gladstone LNG projects to export up to their full capacities, as in the High Scenario. This would occur regardless of whether the contract buyers took their full contract entitlements. The actual level of exports would depend on gas availability and the interaction with domestic prices – if there is insufficient gas supply domestic prices could rise above the value of exports, cutting off total exports below capacity.

Conversely weak LNG demand and over-supply, with low spot LNG prices, provides opportunities and incentives for LNG buyers to cut back contract supply to their take-or-pay levels, as in the Low Scenario. This will reduce demand at Gladstone and tend to push down domestic gas prices.

How this works in the current very low price environment, where spot and contract LNG prices are similar and at recent historical lows, is not clear. Spot oil and spot LNG prices have both reduced substantially since early-2014 in response to over-supply. Starting at \$US100/bbl Brent oil has fallen to below \$US60/bbl, taking contract LNG prices with an index of 0.14 from \$US14/mmbtu to \$US8.40/mmbtu. Asian spot LNG prices have fallen further, from \$US20/mmbtu in early 2014 to about \$US7/mmbtu at present (Figure 2-2). Although the low LNG demand associated with the fall in spot prices suggests that LNG production may not exceed take-or-pay, contract prices are more attractive to buyers than imagined at the time the contracts were negotiated. If the underlying demand growth associated with the contracts (refer to section 2.1.5) is forthcoming, LNG production may reach the full contract level.

### 3.8.2 Electricity demand

Electricity prices can impact the economics of electrically driven field and processing plant compression compared to gas driven compression. At high electricity prices it may be economic to replace grid connected power with gas direct drive or central gas turbine generation powered by project gas. The latter option is more economic, since it uses the electric compressors already in place and in the case of the GLNG Fairview field the gas turbine is also in place so only the short-run gas costs are relevant. In the cases of the QCLNG and APLNG projects the capital costs of the GTs would be incurred.

Alternatively QCLNG and APLNG could divert gas to their affiliated GTs already connected to the Queensland electricity grid, as a hedge against the cost of power exceeding the value of gas. This would not reduce their demand for electricity from the grid however.

Electricity prices at which gas and electrically driven compression breakeven are presented in Table 3-8. The lower spot LNG and oil prices currently prevailing are likely to lead to lower domestic gas prices, and the possibility of short run substitution of gas for electricity is significantly enhanced compared to the perspective in the 2014 Projections.

**Table 3-8 Electricity grid prices at which centralised gas turbine compression power breaks even (\$/MWh, \$2015)**

<b>Gas Price (\$/GJ)</b>	<b>\$4.00</b>	<b>\$6.00</b>	<b>\$8.00</b>	<b>\$10.00</b>
Short-run (\$/MWh)	\$46.61	\$63.41	\$80.21	\$97.01
Long-run (\$/MWh)	\$74.84	\$91.64	\$108.44	\$125.24

### 3.9 Potential for demand-side participation by the LNG plants in response to high electricity prices or high electricity demand

In discussion, participants suggested that during gas production ramp up and LNG commissioning they would prioritise their own operational matters over short-term commercial issues such as responding to high electricity pool prices. Once their operations have reached a plateau phase of production, they would begin to fine tune cost savings and would consider demand side participation by the GPPs.

LGA considers that the economics of grid powered compression are such that demand side participation is unlikely:

- The value of gas for LNG considerably exceeds the cost of electricity to the GPPs, other than at very high pool prices. Electricity usage in the electrically driven GPPs is 7-8 MWh/TJ. The short run marginal value of each TJ at the GPP is defined by the short run netback value of LNG, which ranges from \$5/GJ (\$5,000/TJ) at low oil prices to \$12/GJ (\$12,000/TJ) at high oil prices. The short run value of electricity supply to the GPPs, assuming that there are few if any other short run variable costs other than electricity, therefore ranges from \$625/MWh<sup>41</sup> to \$1,700/MWh. Consequently GPPs would be unlikely to voluntarily curtail electricity usage at pool prices below this range.
- At prices well below this level it could become profitable for LNG projects to divert gas from LNG to gas fired electricity generation, where there is any unutilised generation capacity. The marginal cost of gas fired generation with gas at \$12/GJ, the upper end of its value as LNG, would be approximately \$97/MWh for a typical combined cycle plant and \$158/MWh for a typical open cycle plant. At pool prices above these levels it could therefore be profitable for LNG projects to divert gas from LNG to generation, either in plants owned by their operators (Darling Downs PS is owned by Origin, the upstream operator for APLNG, and Condamine PS is owned by QGC, the upstream operator for QCLNG) or by third parties.

Gas diversion to generation is therefore likely to occur at prices lower than levels at which demand side participation is of interest. The total quantum of diversion could be substantial, simply because total gas production in Queensland is in the process of rising seven-fold from 600 TJ/d to over 4,000 TJ/d, with further capacity in the Roma and Silver Springs storages. Compared to this, peak gas fired generation usage during 2014 was under 500TJ/d.

### 3.10 Confidence in the base scenario projections

The following table describes the levels of confidence LGA ascribes to the components of the base scenario projections up to 2020. Confidence in all projections falls after 2020 as the possibilities leading to variation of outcomes multiply.

High confidence means that the underlying data is known to be accurate and is unlikely to vary within the definition of the base scenario. Reasonable confidence means that the data is estimated from reliable sources/methods or could vary somewhat within the scenario definition. Low confidence means that sources are less reliable or should be expected to vary.

**Table 3-9 Confidence in base scenario projections to 2020**

Component	Confidence Level
LNG start up timing	Reasonable
LNG ramp-up period	Reasonable
Plateau LNG production	High except for QCLNG, which is not defined by specific contracts
Gas used in liquefaction	Reasonable

<sup>41</sup>(\$5000/TJ)/(8MWh/TJ) = \$625/MWh

Component	Confidence Level
Third party contracts	Reasonable.
Equity gas production	Reasonable.
Gas used in production	Reasonable.
Electricity used in production	Reasonable.
Gas production by zone	Low
Electricity usage by zone	Low

### 3.11 Calculating monthly estimates

All estimates have been initially calculated quarterly at average daily rates and quarterly aggregates have been calculated by multiplying by the number of days per quarter.

Monthly estimates have been calculated as follows:

- Second month in quarter: average daily rate = quarterly average; monthly total = average daily rate \* number of days in the month
- First month in quarter: average daily rate =  $A * \text{quarterly average} + (1-A) * \text{previous quarter average}$ ; monthly total = average daily rate \* number of days in the month
- Last month in quarter; monthly total = quarterly total – 2<sup>nd</sup> month total – 1<sup>st</sup> month total;

This calculation is designed to ensure that the sum of monthly totals equals the quarterly total. The parameter A was varied to create smooth monthly estimates and a value of 0.725 was found to minimize variability.

Peak day estimates have been calculated similarly:

- Second month in quarter: peak = quarterly peak
- First month in quarter: peak =  $A * \text{quarterly peak} + (1-A) * \text{previous quarter peak}$ ;
- Last month in quarter; peak =  $3 * \text{quarterly peak} - 2^{\text{nd}} \text{ month peak} - 1^{\text{st}} \text{ month peak}$ ;



## 4. Projections

### 4.1 Annual projections

Total LNG export projections are presented in Figure 4-1, together with the equivalent 2014 projections<sup>42</sup> (dashed lines). The Base scenarios are very similar, reflecting the limited changes to public information on project start-up timing and contracted volumes. There are more significant differences in the High and Low scenarios: in the High scenario the seventh train now comes in two years later; and in the Low scenario exports are 5% lower than previously because the contract take-or-pay level is assumed to be 85% instead of the previous 90%.

Figure 4-1 Total LNG export projections

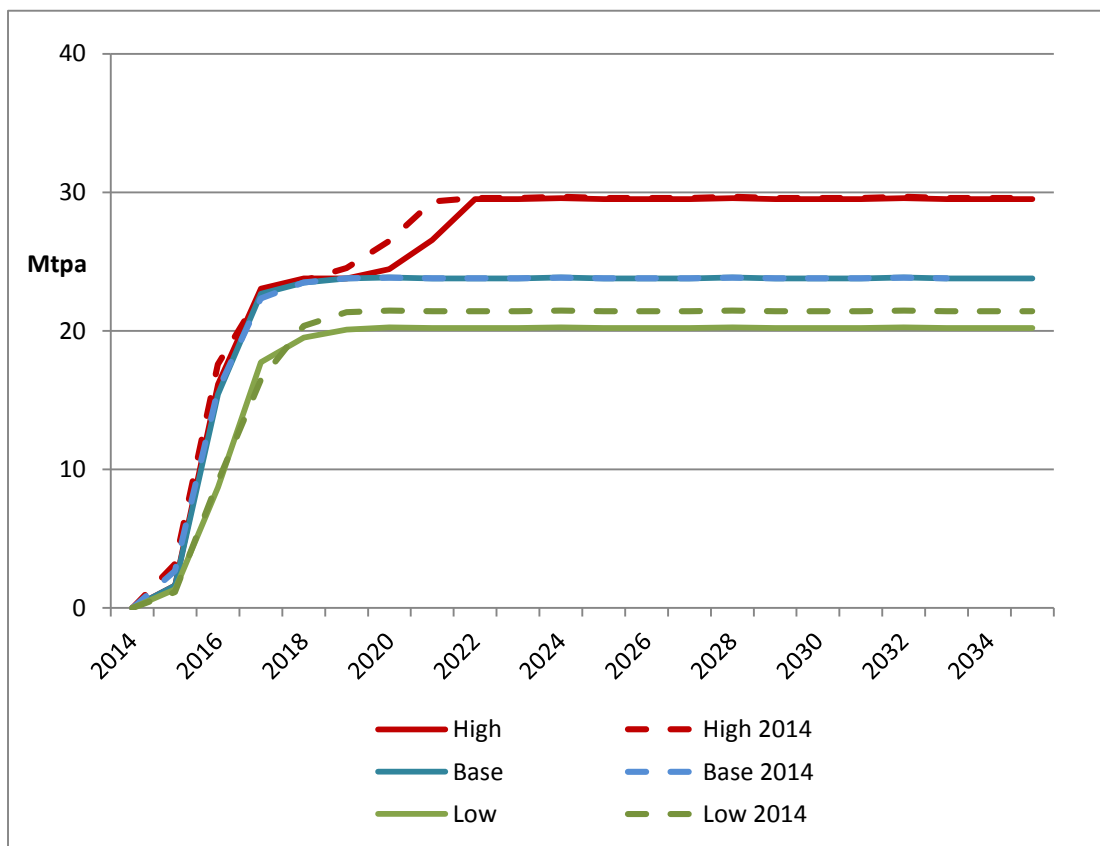
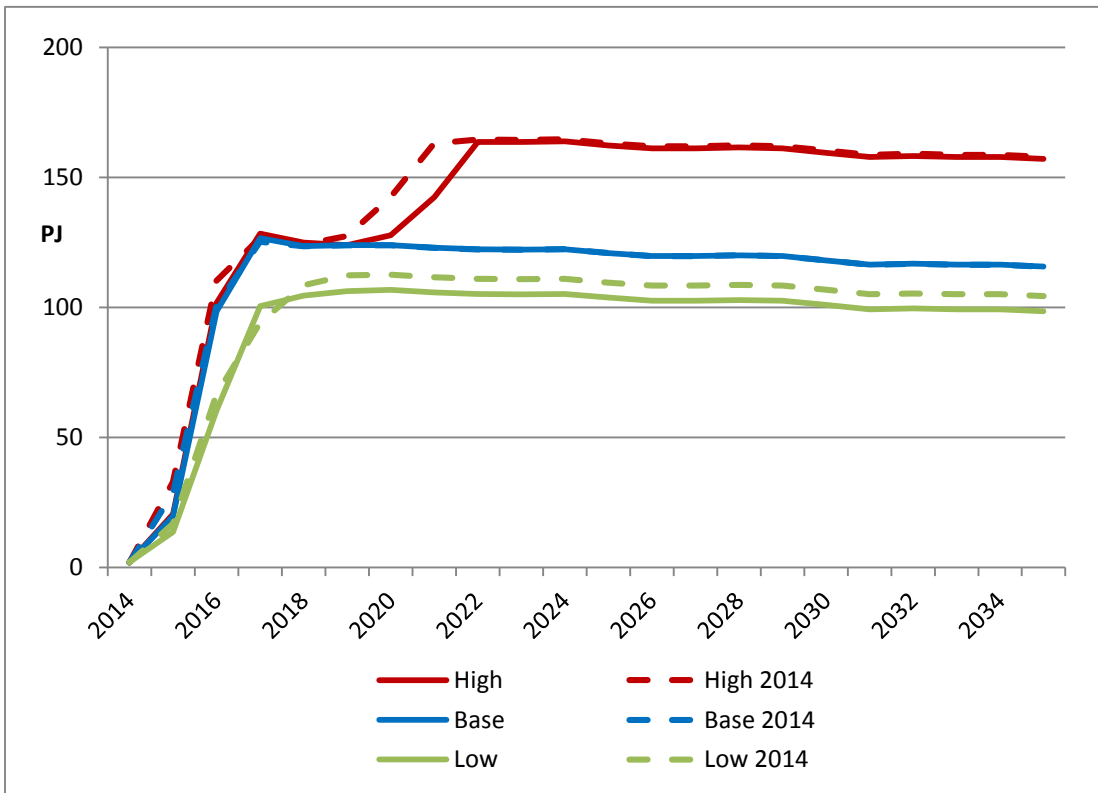


Figure 4-2 and Figure 4-3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production. For gas usage the differences between current and 2014 projections simply follows the differences in export projections discussed above as the usage parameters that have changed the most (APLNG's upstream gas use) apply only to small volumes of production. However the electricity usage projections have substantially increased compared to 2014 because the estimates of electricity used per TJ of gas produced have increased. Further revisions to these estimates over coming months may change the final projections.

<sup>42</sup>These are Jacobs August Revised Projections

**Figure 4-2 Total gas used in liquefaction and production**



**Figure 4-3 Total grid electricity usage**

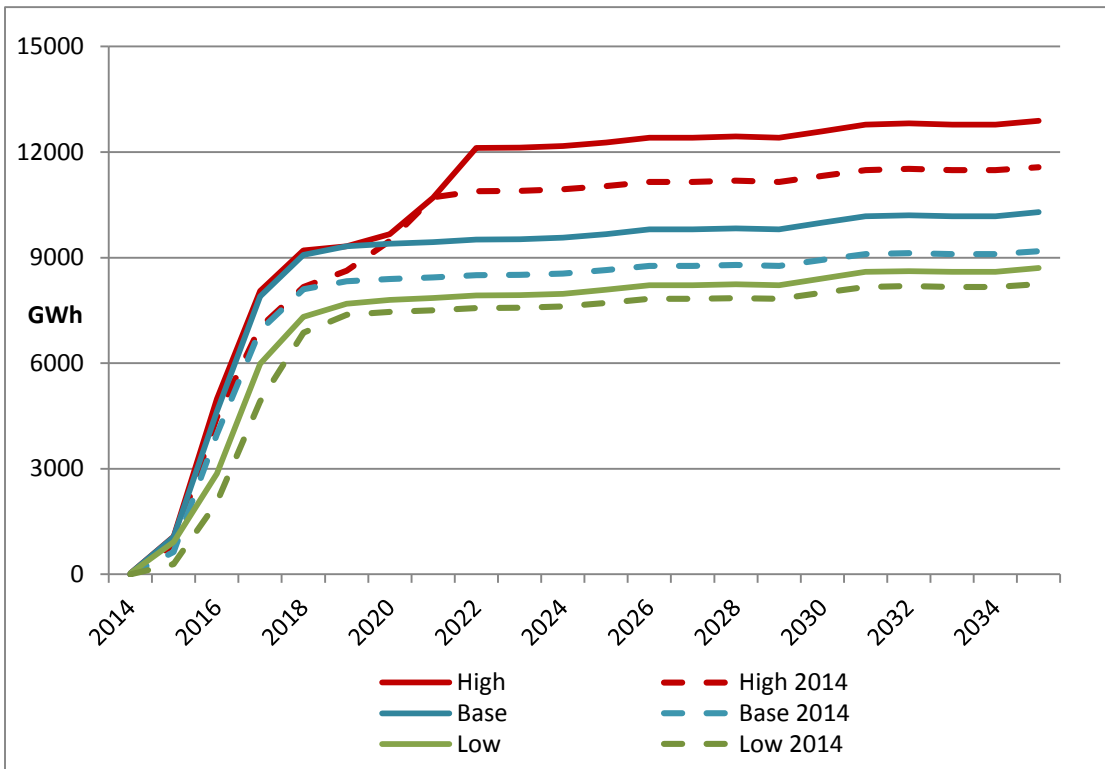
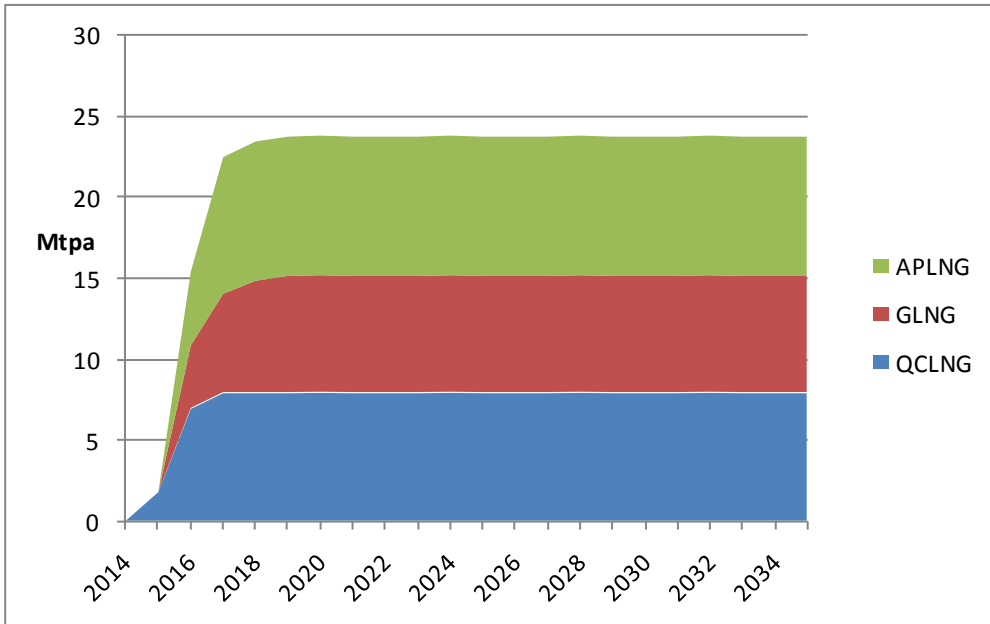
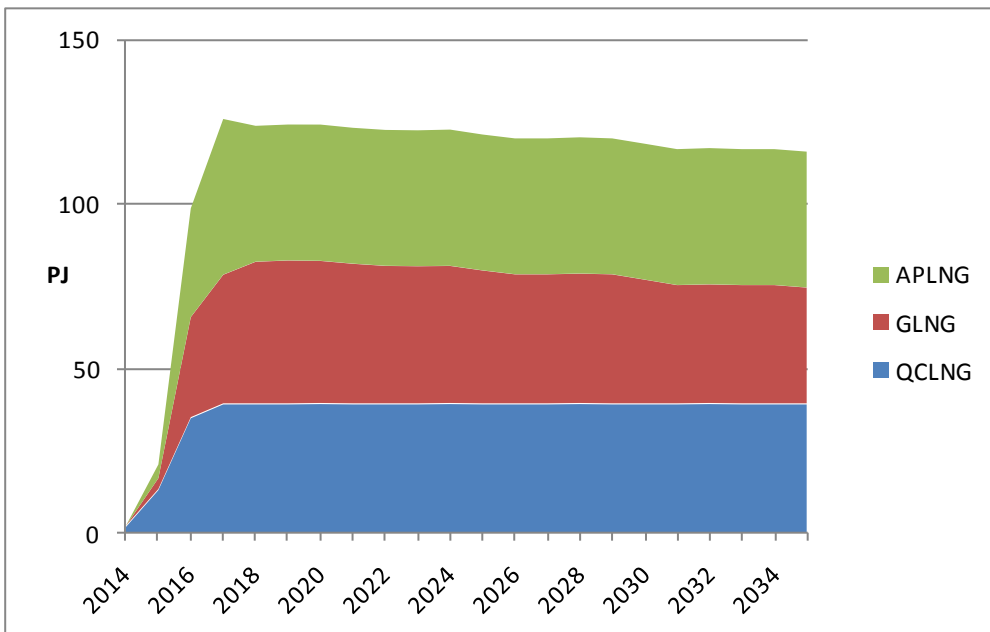


Figure 4-4 to Figure 4-6 show each projects' contribution to the Base Scenario projections, for LNG exports, gas usage and grid electricity usage respectively. It is noted that the GLNG project utilises proportionally more gas and less grid electricity than the other two, owing to its greater reliance on third party gas supply. GLNG's grid electricity usage also increases slowly in the longer term, because it is assumed that as third party contracts end, they are replaced by equity gas which is grid electricity powered.

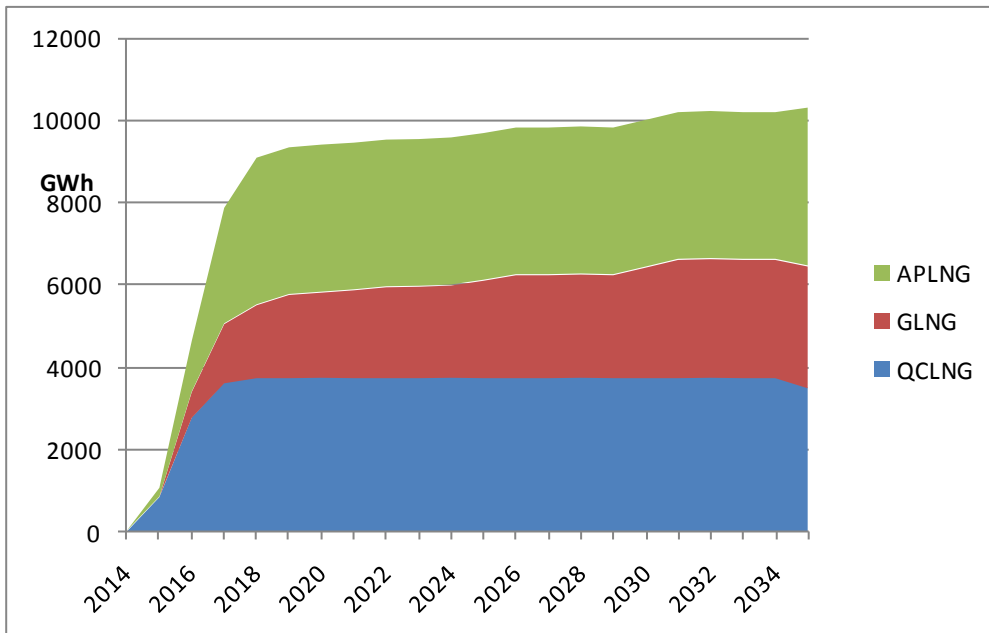
**Figure 4-4 LNG export projections, Base Scenario**



**Figure 4-5 Gas used in liquefaction and production, Base Scenario**



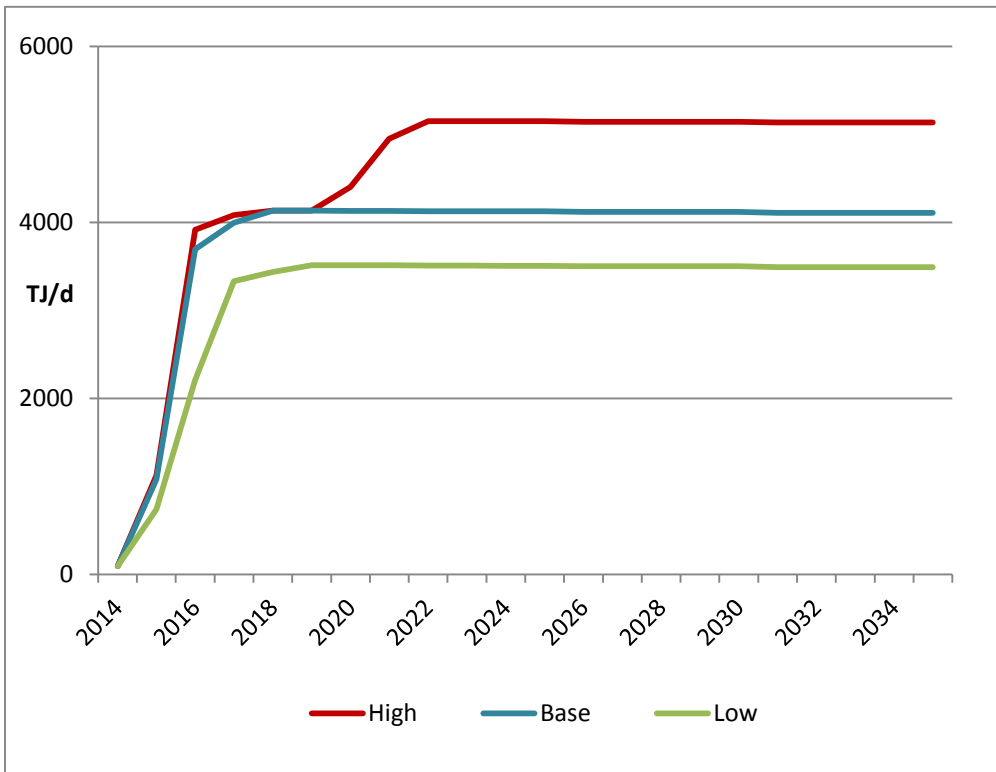
**Figure 4-6 Grid electricity usage, Base Scenario**



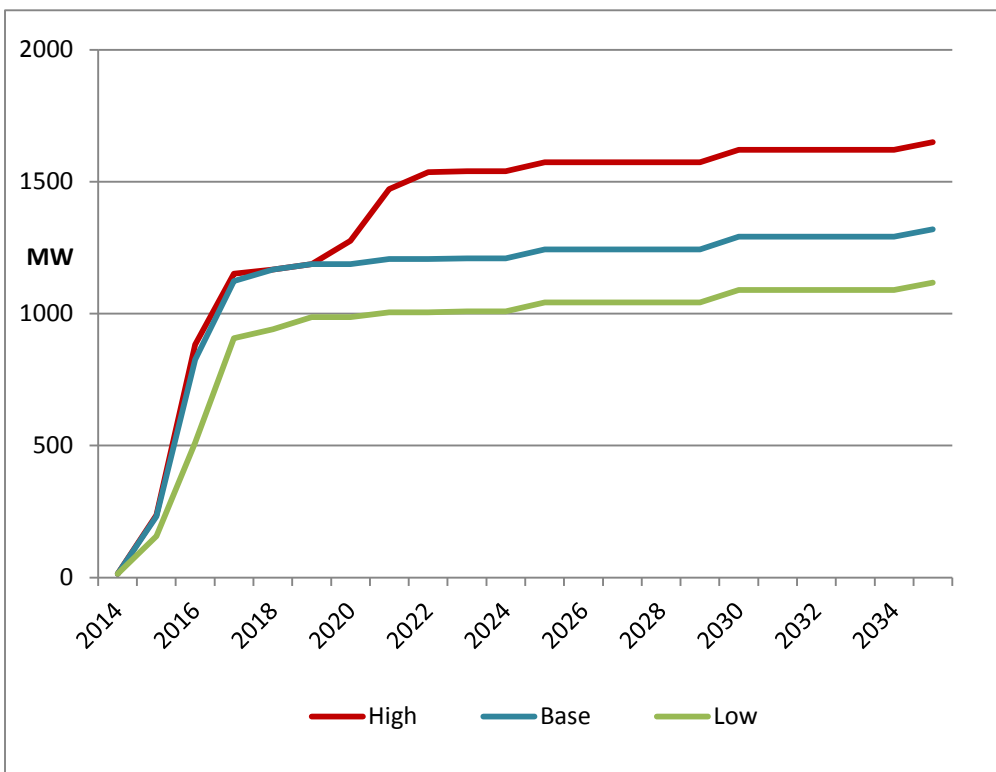
## 4.2 Peak demand projections

Figure 4-7 and Figure 4-8 show the peak gas and peak grid electricity demand projections respectively. Long-term peak gas demand ranges from 3,500 TJ/d in the Low Scenario to 5,150 TJ/d in the High Scenario. The peak gas demands change only imperceptibly after the plateau export levels are first reached. In contrast, peak grid electricity demand increases in parallel with grid electricity usage, even after plateau exports are reached, because it is assumed that third party gas supply, which is assumed to be gas-driven, is replaced by grid electricity driven equity gas supply when the third party contracts end.

**Figure 4-7 Peak gas demand**



**Figure 4-8 Peak grid electricity demand**



### 4.3 Monthly projections

Monthly projections of LNG exports, gas usage and grid electricity usage to 2018 are presented in Figure 4-9 to Figure 4-11. Peaks and troughs are mostly the result of differences in the numbers of days per month. For exports and gas usage, the monthly charts show the limited differences between the current projections and the 2014 projections more clearly than the annual charts. For grid electricity usage, the differences are greater because the estimates of electricity used per TJ of gas produced have increased.

Figure 4-9 Total LNG export projections

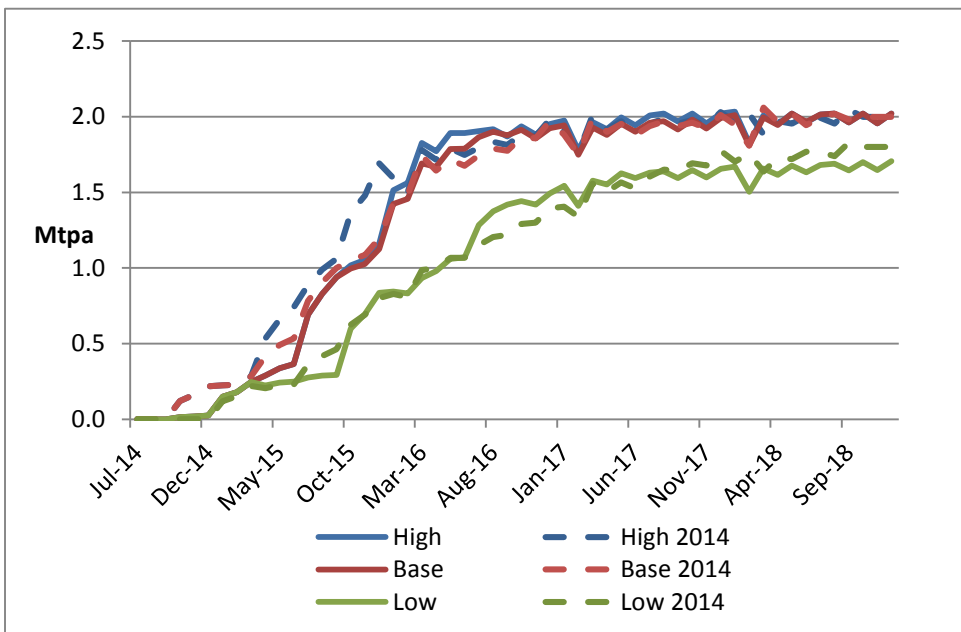


Figure 4-10 Total gas used in liquefaction and production

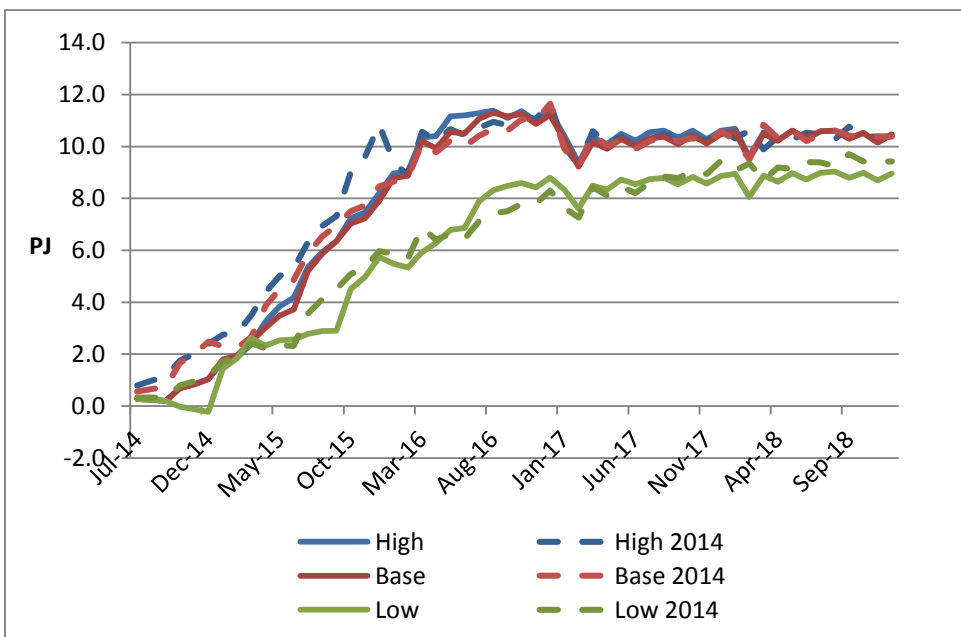
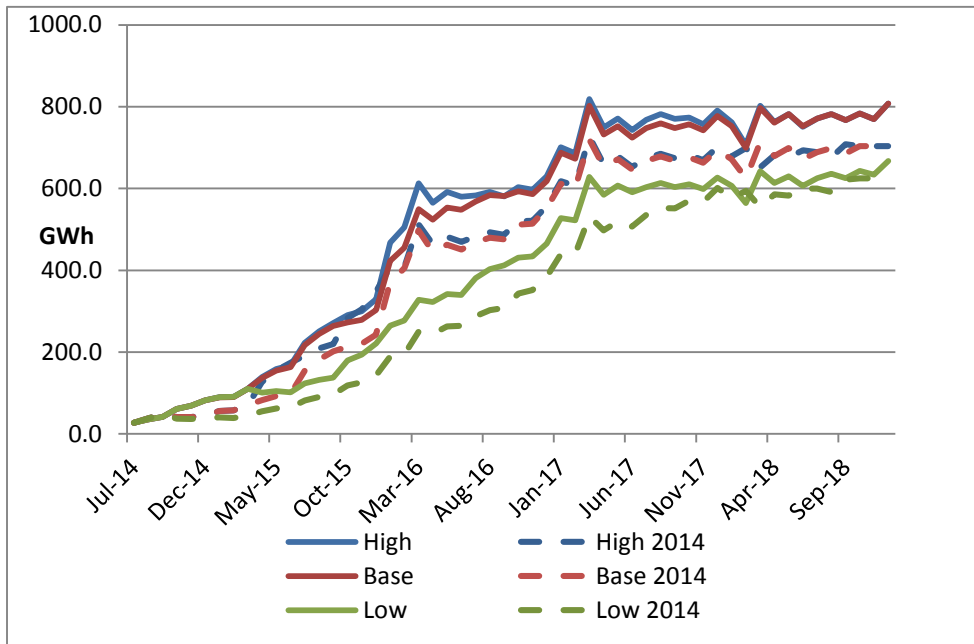


Figure 4-11 Total grid electricity usage



## Appendix A. Abbreviations

2P	Proved and probable reserves (50 percentile estimate of commercial reserves)
AEMO	Australian Energy Market Operator
APA	Australian Pipeline Trust
APLNG	Australia Pacific LNG
BBL	Barrel (of oil)
BREE	Bureau of Resource and Energy Economics
CSG	Coal seam gas (natural gas released from coal seams after drilling)
EHV	Extra High Voltage
FID	Final investment decision
FLNG	Floating LNG
FOB	Free on-board
GJ, TJ, PJ	Giga-, Tera-, Petajoule (10 <sup>9</sup> , 10 <sup>12</sup> , 10 <sup>15</sup> joules)
GLNG	Gladstone LNG
GPP	Gas Processing Plant (also called CPP – Central Processing Plant)
GSOO	Gas statement of opportunities
GT	Gas Turbine
HHV	Higher heating value
JCC	Japan Customs Cleared crude price
LGA	Lewis Grey Advisory
LNG	Liquefied natural gas (gas cooled to -161C)



LRMC	Long run marginal cost
MMBTU	Millions of British Thermal Units
MTPA	Million tonnes per annum (of LNG)
MW	Megawatt
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NGFR	National Gas Forecast Report
ORG	Origin Energy
Q1, Q2, Q3, Q4	First, second, third and fourth quarters of calendar years
QCLNG	Queensland Curtis LNG
SPE	Society of Petroleum Engineers
SRMC	Short run marginal cost
T1, T2	First and second LNG trains