Projections of Gas and Electricity Used in LNG

Public Report

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Lewis Grey Advisory

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2	23/3/16	Final internal draft incorporating AEMO comments	R Lewis
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Contents

Appendix B. 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 a report and dataset providing historical data and forecasts of gas and electricity consumption (annual and maximum/peak daily) related to LNG export for the next 25 years (2015-16 to 2041-42) under various scenarios and conditions by 4 March 2016.

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. More specifically, this project involves:

- Industry (LNG) stakeholder consultation:
  a. Presentation of findings to industry stakeholders.
  b. Making appropriate revisions to draft deliverables based on external stakeholder feedback.
- 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 forecasts, 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.
- Provision of an Excel database(s) proving data underpinning any chart, figure and/or forecasts presented in the report.

This report

This report fulfils the reporting requirements outlined in the Terms of Reference above. The draft was provided on the target date and the report was finalised following discussions with AEMO. This report follows similar reports prepared for AEMO by LGA in April and October 2015, referred to as the 2015 NEFR LNG Projections Report and the 2015 NGFR LNG Projections Report respectively.

The required forecasts of LNG production and the gas and electricity usage associated with this production have been derived from modelling undertaken by LGA based on information in the public domain, much of it provided by the stakeholders on their websites, and incorporating stakeholder feedback.

Summary of findings

Queensland Curtis LNG (QCLNG) commenced exports from its first LNG train on Curtis Island, near Gladstone, in January 2015. This train was declared “commercial” (delivering LNG cargoes according to contract) in May 2015. QCLNG’s second train became operational in July 2015 and commercial in November 2015. The first trains of Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG) started LNG production in September 2015 and December 2015 respectively, and exported their first cargoes shortly thereafter. APLNG announced the transition of its first train to operational status on 3rd March 2016. APLNG’s and GLNG’s second trains are expected to start up in the first half of 2016.

The six LNG trains are each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year when operating at their nameplate capacities. A fourth major project, that of Arrow Energy, was cancelled as a stand-alone project earlier this year and Arrow has yet to indicate how it will try to monetise the value of its gas reserves. Using the gas in a third train at one of the existing projects or another, smaller, project is a widely canvased option. Arrow’s 50% owner, Shell, has recently taken over BG Group, the majority owner of QCLNG.

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. The relevant estimates are used in the preparation of AEMO’s National Electricity Forecast Report (NEFR).

The key elements of the study are:

1. Three scenarios concerning the overall levels of exports.
2. A 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.
4. Additional commentary on the factors that will affect levels of exports and the achievement of export targets.

Since the 2015 NGFR LNG Projections were finalised, the LNG project operators have not notified external stakeholders of any major changes to the projects and LNG production has ramped up at or above previously projected rates. Consequently the Neutral Scenario is very similar to the Base Scenario in the 2015 NGFR LNG Projections.

Likewise LGAs’ methodology for estimating electricity and gas used in the LNG supply chain remains essentially the same but with updated parameter estimates based on actual gas and electricity usage. Some material parameter estimates continue to rely upon an APLNG report released through its regulatory approval process[1], referred to as Reference 1 in the remainder of the report.

More significant changes have been made to the methodologies for estimating peak demand for gas and electricity, which recognise the fundamental role of the LNG plant capacities in setting peak demand.

[1] Upstream Basis of Design, APLNG Upstream Project. Attachment 2 to APLNG application to construct Talinga-Condabri Interconnect Pipeline. Available at www.dilgp.qld.gov.au

LNG Export 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:

- Neutral 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.

- Weak Scenario – the six trains operating 15% below contract (approximately 20 Mtpa), with slower ramp-up. Under AEMO's oil/LNG price assumptions associated with this scenario, replacement of declining CSG production capacity comes into question and after 2030 both CSG and LNG production are assumed to decline rapidly.

- Strong Scenario – the six trains operating initially at 100% of nameplate capacity (above contract) with faster ramp up, and at 105% of nameplate capacity from 2021 after additional supply has been developed. A seventh train of 4.5 Mtpa capacity is added in 2027. Total production ultimately reaches 31 Mtpa.

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

Scenario selection is based upon global LNG demand and supply projections produced by third parties. As such these projections are only indirectly connected to AEMO's scenario definitions.

Gas and Electricity Usage Methodology

The methodology used in this study is a further extension of the methodologies applied in the 2015 NEFR LNG Projections Report and the 2015 NGFR LNG Projections Report.

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. Average usage is estimated to be 7% of gas input to the plant, with some seasonality.

- 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 usage figures represent a small decrease compared to 2015 NGFR LNG Projections Report estimates.

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

		QCLNG	GLNG	APLNG
Gas driven plant	Gas	5.0%	6.5%	6.5%
Electricity driven plant	Electricity	2.09%	2.46%	2.09%
Electricity driven plant	Gas	1%	0%	1%

Sources: Queensland Department of Natural Resources and Mines; AEMO; Reference 1

Export and Energy Usage Projections

Total LNG export projections are presented in Figure E 1, together with the equivalent projections from the 2015 NGFR LNG Projections (dashed lines). The Neutral Scenario is almost unchanged relative to the 2015 Base Scenario while the Strong Scenario is 2% higher than the 2015 High Scenario owing to revised estimates of LNG plant capacities. The Weak Scenario is similar to the 2015 Low Scenario until 2030 but thereafter it declines owing to non-replacement of CSG production capacity due to low oil/LNG prices. Export levels range from 20 Mtpa in the Low scenario to over 31 Mtpa in the High scenario.

Figure E 1 Total annual LNG export projections (Financial Year)

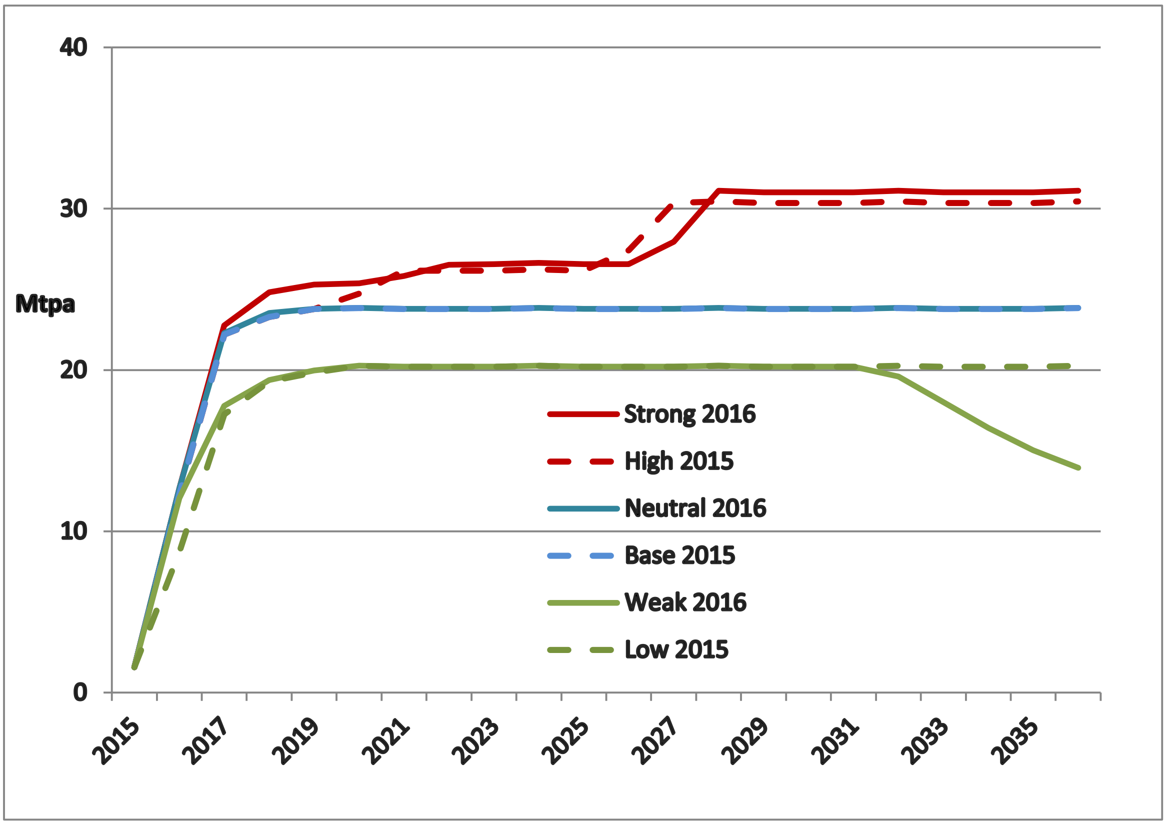


Figure E 2 and Figure E 3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production.

For gas usage the scenario relativities largely track the export relativities, as few changes have been made to the assumptions. However, for electricity usage the 2016 projections are 3% to 10% lower than their 2015 counterparts due to use of a lower estimate of electricity usage per unit of gas production, based on most recent data (refer to section 3.6.3). In energy terms the reductions in electricity usage range from 220 GWh per year in the Weak Scenario to 1,100 GWh per year in the Strong Scenario.

Figure E 2 Total annual gas usage in liquefaction, transmission and production (Financial Year)

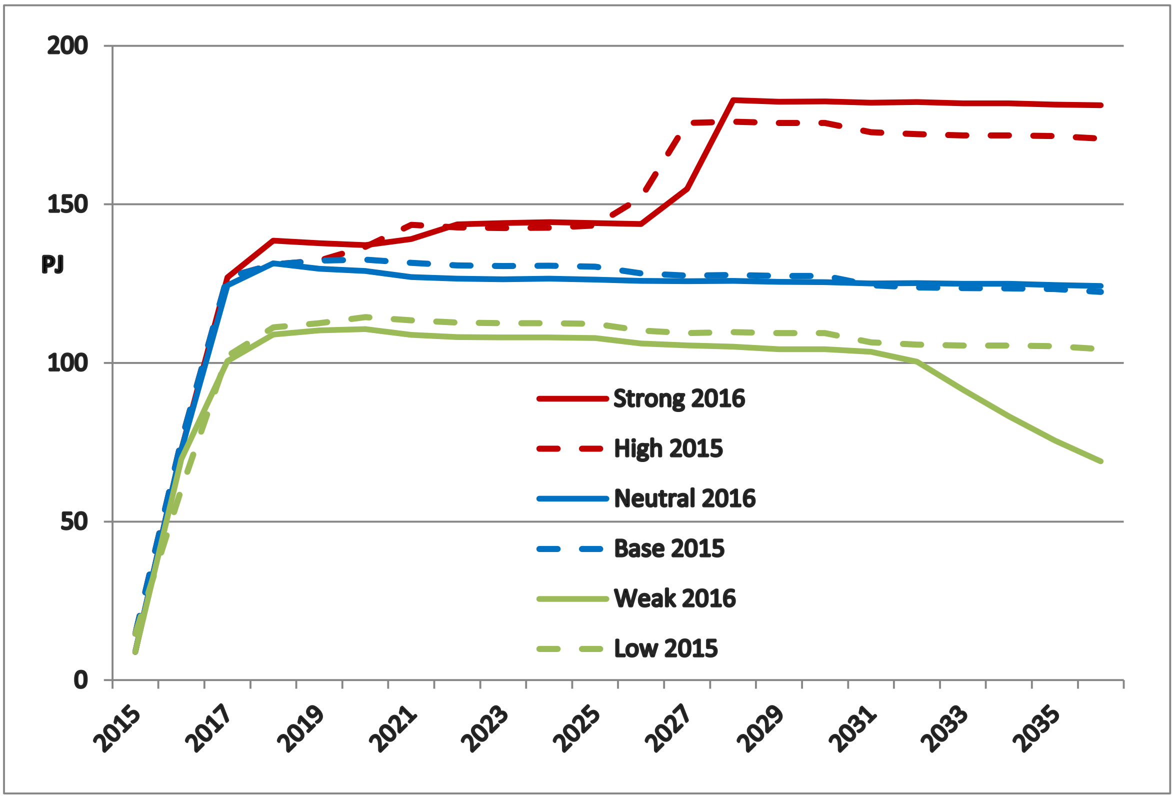
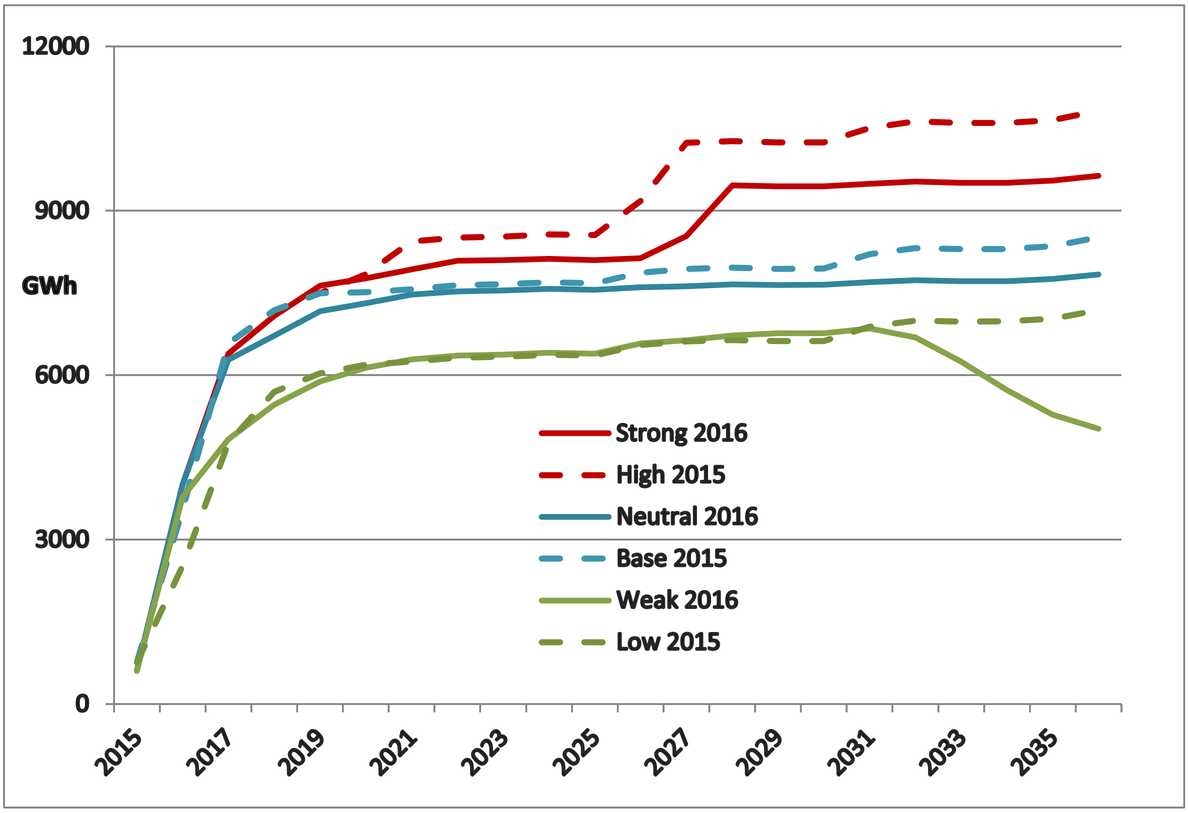


Figure E 3 Total annual grid electricity usage (Financial Year)



Summary of changes to the projections

Changes to the projections in this report compared to the 2015 NGFR LNG Projections are summarised below. It is emphasized that the changes reflect more detailed analysis of recent actual gas and electricity usage by the LNG projects rather than any changes announced by the project operators.

- Global LNG market – weak demand and prices continue to be the main feature. These have not affected the Gladstone LNG start-ups however.
- LNG exports – with just two trains yet to start production, no changes to timing of start-up; no changes to ultimate volumes in the Neutral Scenario; a 2% increase in the Strong Scenario; and a Weak Scenario in which low oil/LNG prices result in non-replacement of CSG production capacity and consequently falling LNG production after 2030.
- Gas used in liquefaction – no changes in methodology or parameters.
- Gas used in transmission compression (Strong Scenario only) - no changes in methodology or parameters.
- Gas used in processing – a decline of 2% in estimated gas usage per unit of gas production, due to data updates.
- Grid-supplied electricity used in processing – a decline of 6.5% in estimated electricity usage per unit of gas production, due to data updates.
- Peak gas and electricity demand – a revised methodology relates peak demand to peak LNG processing capacity and results in similar projections across the three scenarios

1. Introduction

1.1 LNG exports from Gladstone

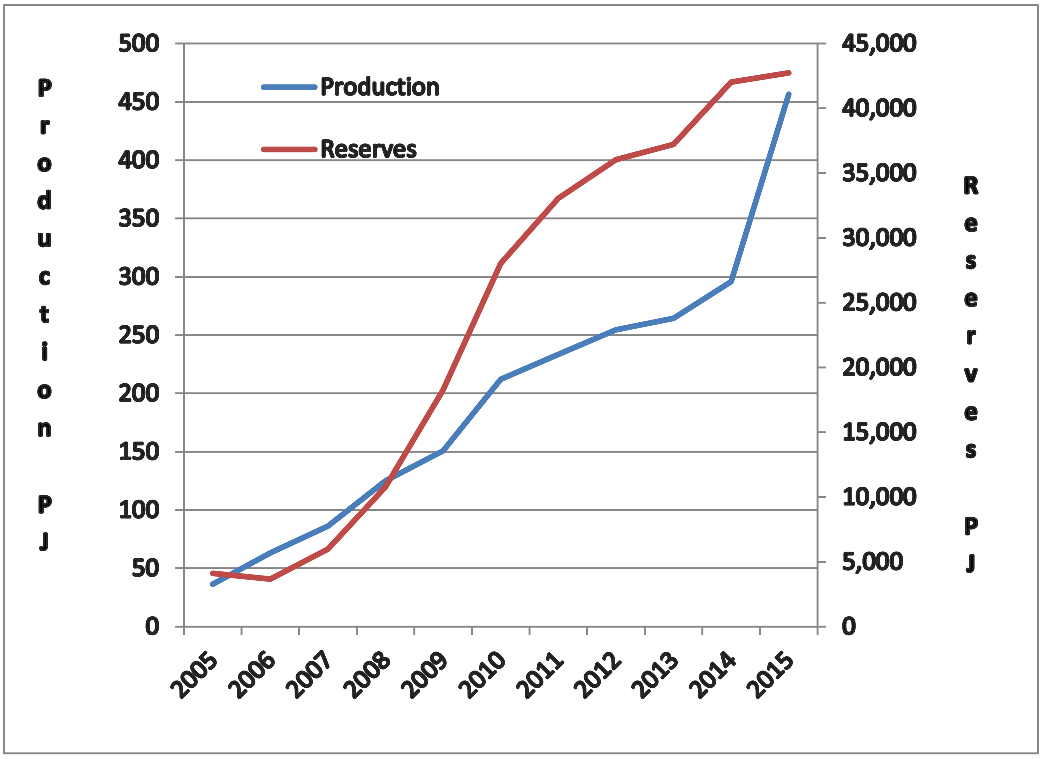
LNG exports from Gladstone were first conceptualised in 2007 and after successful planning and marketing phases, three projects commenced construction in 2011/12. First exports started in early 2015 and four of the six planned trains are now operational, with the remaining two due online in the first half of this year. Production is expected to reach full capacity by 2018.

The key driver of this export program has been the development of economic extraction technologies for coal seam gas (CSG), which 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.

Figure 1-1 illustrates the development of Queensland CSG reserves and production from 2005 to 2015. Since 2007 the reserves have been developed to support the production growth that started in 2015 and will ultimately take production to over 1,000 PJ/yr.

Figure 1-1 Queensland CSG Reserves and Production (Years Ending 30 June)



Source: Queensland Department of Natural Resources and Mines

1.2 The export projects

Queensland Curtis LNG (QCLNG) commenced exports from its first LNG train on Curtis Island, near Gladstone, in January 2015. This train was declared "commercial" (delivering LNG cargoes according to contract) in May 2015. QCLNG's second train became operational in July 2015 and commercial in November 2015. The first trains of Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG) started LNG production in September 2015 and December 2015 respectively, and exported their first cargoes shortly after start up. APLNG announced the transition of its first train to operational status on 3rd March 2016. APLNG's and GLNG's second trains are expected to start up in the first half of 2016.

The six LNG trains are each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year when operating at their nameplate capacities. A fourth major project, that of Arrow Energy, was cancelled as a stand-alone project in 2015 and Arrow has yet to indicate how it will try to monetise the value of its gas reserves. Using the gas in a third train at one of the existing projects or another, smaller, project is a widely canvased option. Arrow's 50% owner, Shell, became the majority owner of QCLNG on 16th February 2016, when it completed its take-over of BG Group[2].

The purpose of this study is to provide AEMO with consistent estimates[3] 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 2016 NEFR, in the same manner as in 2015.

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 20th March 2016. Since that date the following potentially material information has become known:

- Nil.

[2] In this document the name BG Group is retained only in relation to references that were issued by BG Group prior to the take-over.
[3] In particular, changes in export outlook can be consistently incorporated into both gas and electricity forecasts

2. LNG Export Scenarios

2.1 Determining factors

LGA has constructed three scenarios for LNG exports from eastern Australia based on near-term, mid-term and long-term considerations. These are:

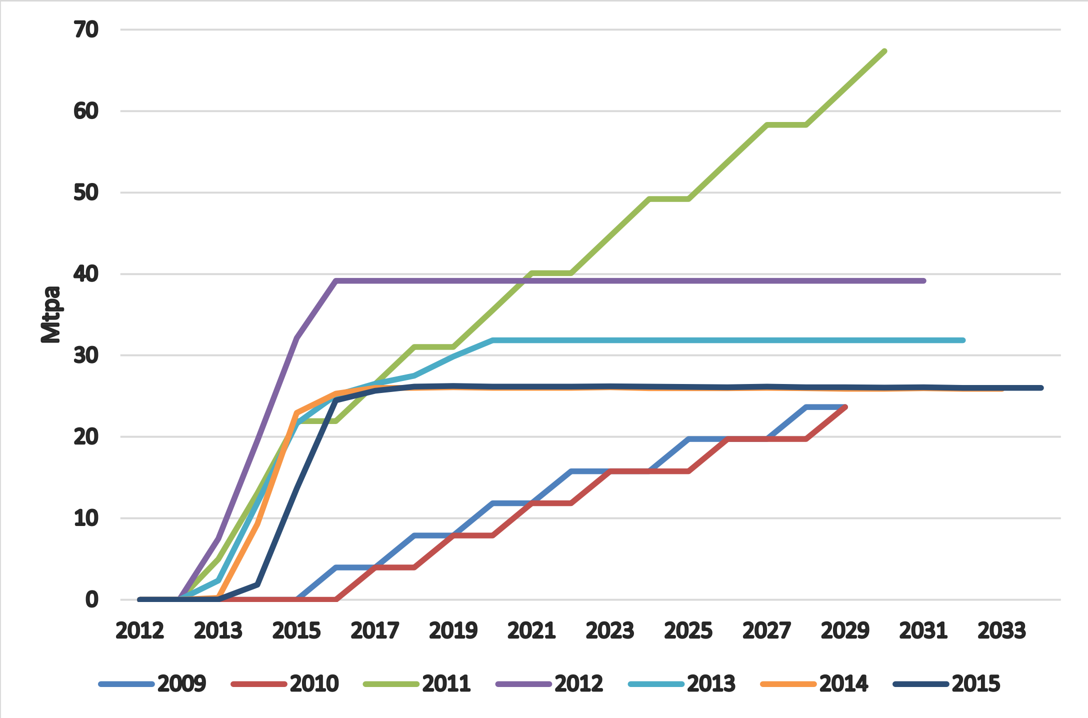
- AEMO planning and forecasting scenarios
- LNG projects operating, under construction and planned
- Gas resource availability
- Global LNG demand and competition from other suppliers.

  As with the 2015 NEFR LNG Projections and the 2015 NGFR LNG Projections, this study relies upon global LNG demand and supply projections prepared independently by third parties and as such these projections are only indirectly related to AEMO's scenarios. This approach was designed for the earlier projections, in which the key uncertainty was the timing of LNG start up, but once all six trains are operational it will be desirable to have a more integrated approach to future capacity expansion and plant utilisation, taking into account global LNG demand and supply.

There have been no material developments in the first three of the above factors since the 2015 NGFR LNG Projections were released. Oil and LNG spot prices, together with global LNG demand, remain weak and the outlook is for this to continue in the near term. Market analysts have questioned whether the Queensland LNG projects will meet their production targets but initial production by two of the project operators has actually exceeded their contracted output levels.

The Base/Medium Scenario export projections from earlier AEMO projections, for the Gas Statement of Opportunities from 2009 to 2013 and for the National Gas Forecasting Report in 2014 and 2015, are illustrated in Figure 2-1. The projections reflect the information available when they were prepared, for example, before any LNG projects reached FID it was assumed that 2nd, 3rd and 4th projects would be delayed, so that exports would ramp up gradually to 25 Mtpa as in the 2009 and 2010 projections. Once three projects had reached FID and CSG reserves had grown dramatically, the projections became much more bullish (2011). Subsequent projections gradually wound back on this as cost overruns and weakening global markets created doubts about the LNG market and Queensland's strength as a supplier.

Figure 2-1 AEMO Queensland LNG export projections 2009 to 2015, Base/Medium Scenarios



2.1.1 AEMO planning and forecasting scenarios

AEMO has developed three scenarios for use in AEMO's planning studies in 2016[4], determined by population, the economy facing consumers and consumer confidence. Most other detail assumes retention of the status quo, recent announcements and near-horizon technologies. The scenarios are labelled Strong, Neutral and Weak, rather than High, Medium and Low, to avoid any connotation that strong economic growth, for example, necessarily correlates with high grid energy demand. The three scenarios are broadly defined in Table 2-1. Scenario assumptions related to LNG exports are set out in Table 2-2.

Table 2-1 AEMO 2016 Scenarios

Scenario Factor	Weak	Neutral	Strong
Population	ABS trajectory low	ABS trajectory medium	ABS trajectory high
Economy	Weak	Neutral	Strong
Consumer confidence	Low confidence, less engaged	Average confidence and engagement	High confidence, more engaged

[4] AEMO Scenarios for 2016. AEMO 25 January 2016.

Table 2-2 AEMO Scenario Gas and LNG assumptions

Scenario Factor	Weak	Neutral	Strong
International oil price	$US30/bbl	$US60/bbl	$US90/bbl
$A/$US exchange rate	0.65	0.75	0.95

2.1.2 LNG projects under construction

The three Queensland LNG export projects outlined in section 1 have the following features:

1) Each project has sold gas under long-term contracts with two or more buyers. QCLNG will also sell to Shell portfolio customers in the Asia-Pacific region. The durations of all contracts are 20 years or longer, starting when the relevant LNG train becomes commercial and its operation passes from the constructor to the owner/operator, which is typically six months after production start-up. During the start-up phase the projects sell commissioning cargoes on a lower delivery commitment basis.

2) Each project has constructed 2 LNG processing trains, of 3.9 to 4.5 Mtpa capacity, on Curtis Island off Gladstone.

Table 2-3 Gladstone LNG Project Parameters

Project	Partners	Nameplate Capacity (Mtpa)	Sales Contracts	
			Party	Volume (Mtpa)
QCLNG[5]	Shell (73.75%)	8.5	*CNOOC*	*3.6*
	CNOOC (25%)		*Shell*	*2.7*
	Tokyo Gas (1.25%)		*Tokyo Gas*	*1.2*
			Chubu Electric	*0.5*
			Total	8.0
GLNG[6]	Santos (30%)	7.8	*Petronas*	*3.6*
	Petronas (27.5%)		*Kogas*	*3.6*
	Total SA (27.5%)		Total	7.2
	Kogas (15%)			

[5] bgdatabook 2014
[6] STO 2014 Investor Seminar, 26 November 2014

Project	Partners	Nameplate Capacity (Mtpa)	Sales Contracts	
			Party	Volume (Mtpa)
APLNG[7]	Origin Energy (37.5%)	9.0	*Sinopec*	7.6
	Conoco Phillips (37.5%)		*Kansai Electric*	1.0
	Sinopec (25%)		Total	8.6

3) Each project has developed 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 was sold 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.

6) A further dimension to the projects was added by Origin Energy's 1st March 2016 announcement[8] of a non-binding heads of agreement to sell LNG to ENN Energy of China based on Origin's 260 PJ Ironbark CSG field, which it owns independently of APLNG. The HoA is for 0.5 Mtpa (27.5 PJ) for 5 years from 2018 or 2019. The gas may not be processed at the APLNG plant part owned by Origin. Owing to the non-binding nature of the HoA these sales are not included in in the Neutral Scenario.

2.1.2.1 Further trains for these projects

APLNG[9] has environmental approval for 4 trains and QCLNG[10] and GLNG[11] 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 project's gas reserves). BG Group had stated that it does not anticipate making a decision of a third train at QCLNG in the near future[12] but this may no longer apply under Shell management.

[7] Origin Energy International Roadshow , September-October 2014
[8] Origin Energy Website
[9] Queensland Co-ordinator General Website
[10] Ibid
[11] GLNG Project Environmental Impact statement - Executive Summary.
[12] BG Group 2013 4th quarter & full year results transcript (4th Feb 2014)

2.1.3 Planned projects

A fourth two train LNG project planned for Curtis Island, proposed by Arrow Energy, was cancelled in January 2015[13]. Arrow is now officially trying to find the best monetisation option for its CSG reserves, which include discussions on collaboration opportunities. Given Shell's common ownership of Arrow and QCLNG, if the most economic opportunity is supplying an extra train, this is most likely to be a third train at QCLNG.

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 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[14]. 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 2022. Projects that may proceed after 2022 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 (Figure 1-1), 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 AEMO 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 were 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. AGL recently announced the abandonment of its Gloucester Basin Project on the grounds that expected gas production rates are sub-economic[15] and Santos has reclassified its Gunnedah 2P reserves as 2C contingent resources[16].

4) As a result of both the above and the shale gas success story in the US, the focus of exploration in eastern Australia moved from CSG to shale gas, with interest mainly in the Cooper Basin because of its well-developed gas gathering and processing infrastructure.

5) Interest in the Northern Territory basins has also increased and the NT Government has sponsored a conditional agreement with Jemena Pipelines to construct a transmission pipeline from Tennant Creek to Mt Isa. NT gas is more likely to be exported from Darwin than from Queensland however.

[13] "Shell shelves Arrow LNG project in Queensland. Brisbane Times January 30, 2015.
[14] Courier Mail 30 March 2015
[15] Review of gas assets and exit of gas exploration and production. AGL Media release, 4th February 2016.
[16] Reserves Statement for the year ending 31st December 2015. Santos, 19 February 2016.

6) All of the above factors have now been overtaken by the imperative to reduce exploration and development budgets, forced on companies by the decline in global oil and gas prices since 2014. Many developments are on hold until there are signs that the price decline has started to reverse, such as consistent falls in oil inventories.

2.1.5 Potential Queensland Projects

In 2014, prior to the fall in LNG and oil prices, the Oxford Institute for Energy Studies (OIES) examined the challenges facing future, as yet uncommitted, Australian LNG projects[17]. At that time there were 20 Australian LNG projects under consideration, at various stages of planning, the majority of which were brownfield expansions of existing projects, that would exploit the 30% to 40% cost savings available through sharing infrastructure and make them competitive with projects in the US, Canada and East Africa. OIES concluded that Australian greenfield projects would not be cost competitive.

OIES estimated that there was just under 50 Mtpa of potential brown field or floating LNG expansion capacity, of which only 4 Mtpa was based on Queensland CSG, using Arrow's gas resources. Based on market conditions in 2014, OIES estimated that 20-25 Mtpa of Australian LNG could reach FID by 2020, including the single Queensland CSG project. These projects would enter production by 2025.

In the following section we examine how this may be affected by recent changes in market conditions.

2.1.6 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[18]. 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.

In view of its position at the top of the gas supply cost curve LNG can readily be displaced by cheaper indigenous supply or pipeline imports. This creates significant uncertainty in future demand, notwithstanding LNG's strong growth up to 2010. Other factors influencing LNG demand are the same as for gas itself, including economic growth, competition from other fuels, including renewables, and energy efficiency, and all of these factors add further uncertainty to LNG demand.

The predominant 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 in Asia and Argentina, Brazil and Chile in South America. 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.

[17] The Future of Australian LNG Exports, Oxford Institute for Energy Studies, September 2014.
[18] Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014.

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, for example in the form of a newly constructed gas-fired electricity generation plant

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[19]. At the same time Japanese demand for gas for generation increased due to the withdrawal of nuclear generators following the Fukushima incident in 2011. Such imbalances are managed via the LNG spot trade and as a result of the above Asian spot prices were high between 2012 and 2014. However the imbalance reversed during 2014 and 2015, as additional supply from PNG and Australia entered the market and Chinese demand growth slowed dramatically.

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 even though there was little evidence of this during 2015. In the longer term however LNG demand is subject to competition from domestic supply and international pipelines, for example:

- European demand is met primarily by a combination of domestic supply, which is declining, imports from Russia and LNG, which provides a counter to Russian market power.
- In the US, 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 now being converted to export terminals.
- China is developing down the European route, 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, as well as LNG.

The OIES has recently provided an assessment of LNG demand incorporating the above factors[20], in particular the impact of competition to LNG from Russian pipeline supply, which strongly depends on whether Russia's pricing policy is to maximise revenue or market share, and alternative levels of Chinese LNG demand. This study is one of the few that explicitly address the impact of current market conditions and provides alternative scenarios. The Department of Industry, Innovation and Science (DoIIS) has recently released its single scenario projection of LNG demand and supply[21], which is compared with the OIES Scenarios in Table 2-4. DoIIS expects strong growth to 2020, though lower than OIES, but much weaker growth from 2020 to 2030. The reasons behind these differences are not known but reflect the uncertainties inherent in LNG demand.

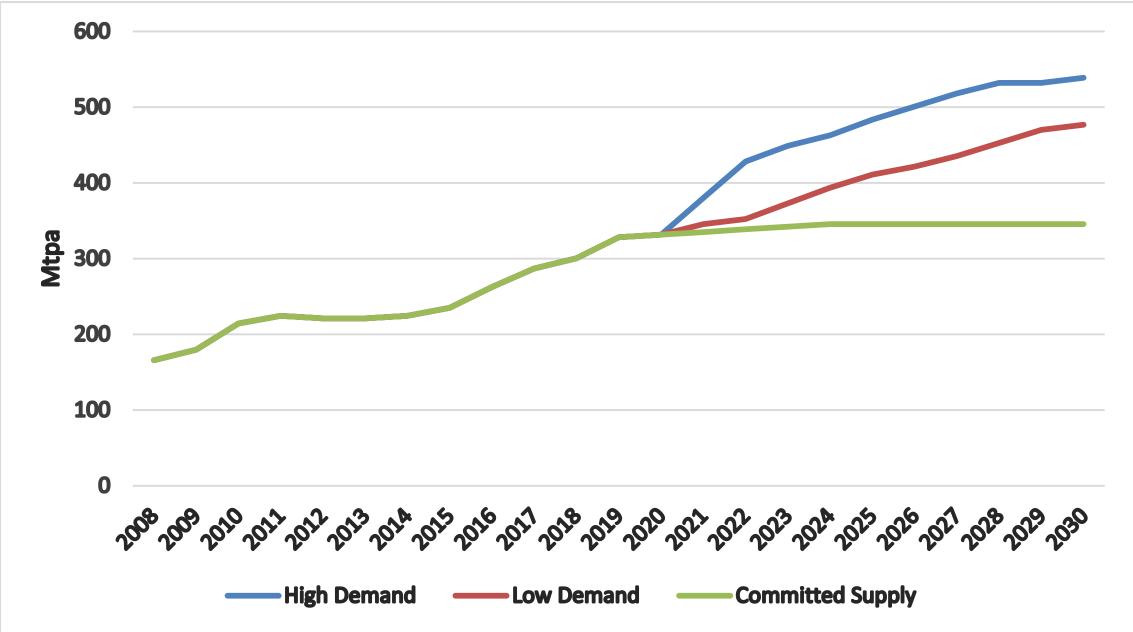
OIES projections are compared with committed supply in Figure 2-2. The High and Low projections are the same as committed supply up to 2020 because it is assumed that supply is priced to clear the market from 2016 to 2020. The major differences post-2020 are due to higher Chinese demand and higher Russian prices and more LNG into Europe in the High Projection. These projections are converted into new LNG capacity requirements and compared to the 2014 projections sourced from OIES in Figure 2-3. The High projection is essentially a two-year delayed version of the 2014 projections, while the Low projections exhibit significant additional delays.

Price projections corresponding to the High and Low demand projections are shown in

[19] Egypt has withheld gas for its domestic market and Angola LNG has suffered technical failures.
[20] The Impact of Lower Gas and Oil Prices on Global Gas and LNG Markets, Oxford Institute foe Energy Studies, July 2015.
[21] Gas Market Report 2015, Department of Industry, Innovation and Science, March 2016.

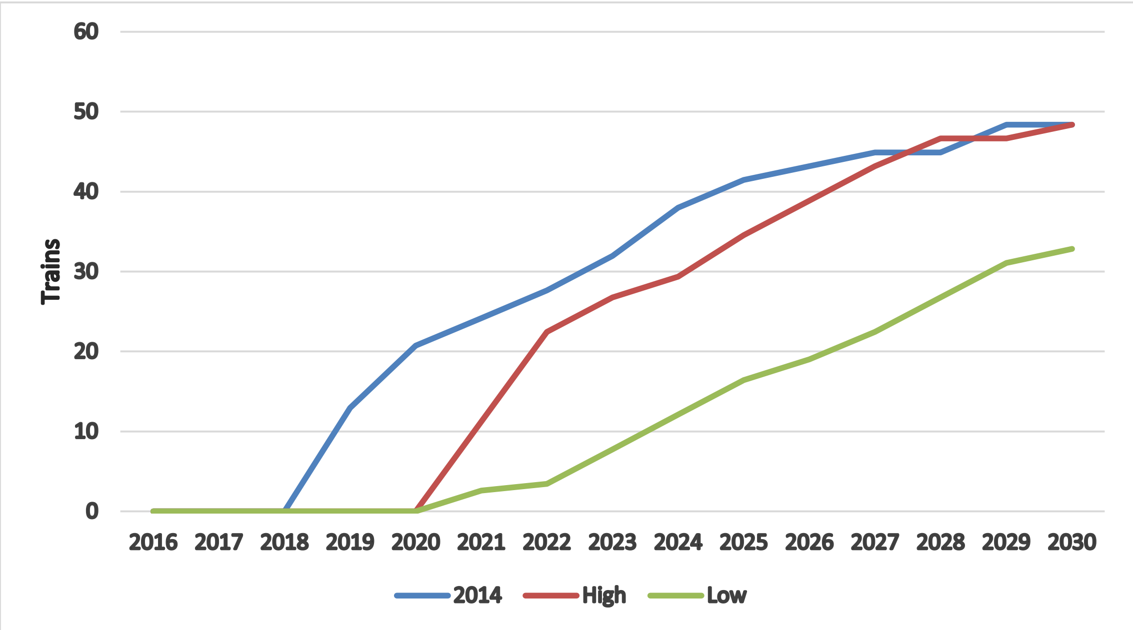
Figure 2-4 and Figure 2-5. In the High projection, Asian spot LNG and European Gas Hub prices rise from their current lows to levels sufficient to support new LNG capacity investments by 2020 whereas in the Low projection this takes substantially longer. From the perspective of the AEMO scenarios, the prices in OIES High projections are broadly consistent with the Strong scenario and the prices in OIES Low projections are broadly consistent with the Neutral scenario. We therefore use the High projection train requirements to define new trains in the Strong scenario and the Low projection train requirements to define new trains in the Neutral scenario.

Figure 2-2 LNG Global Demand Projections, compared to committed supply (Mtpa)



Source: OIES Scenarios 1 and 2, converted to Mtpa

Figure 2-3 Additional LNG Trains required



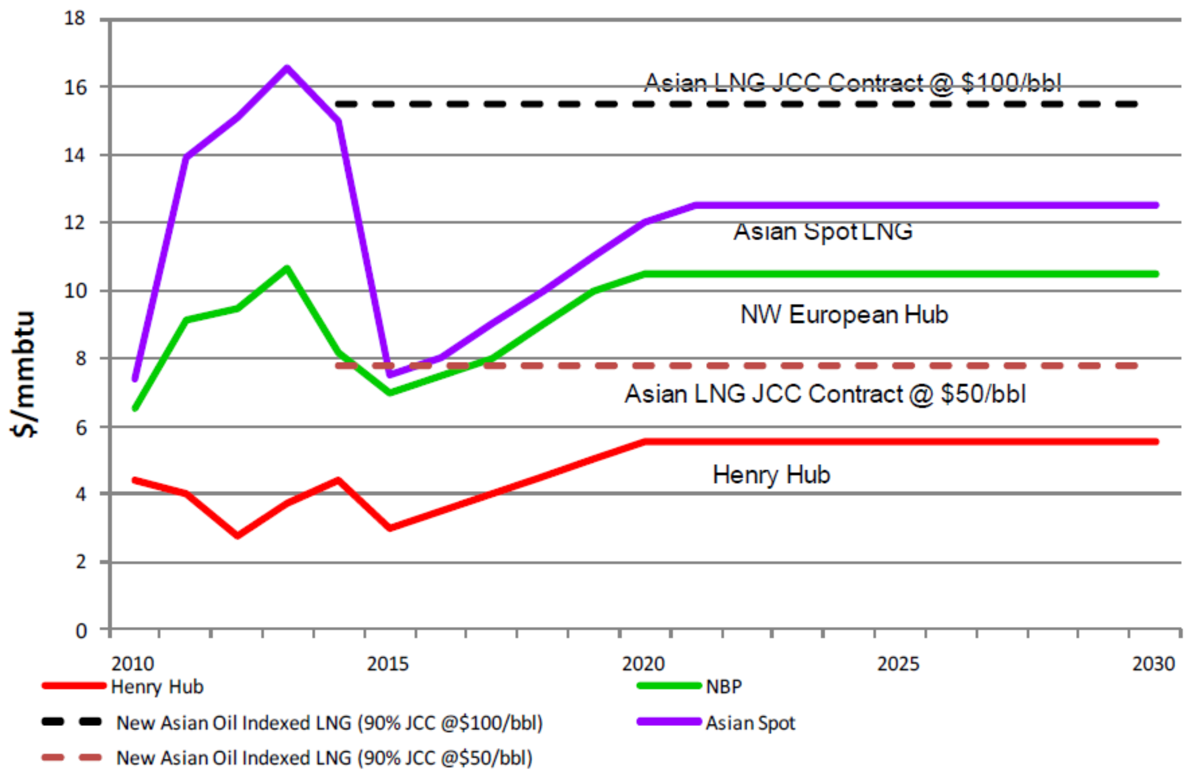
Source: LGA estimates based on OIES

Table 2-4 Global LNG demand projection comparison (Mtpa)

	2020	2030
OIES High	332	539
OIES Low	332	477
DoIIS	316	373

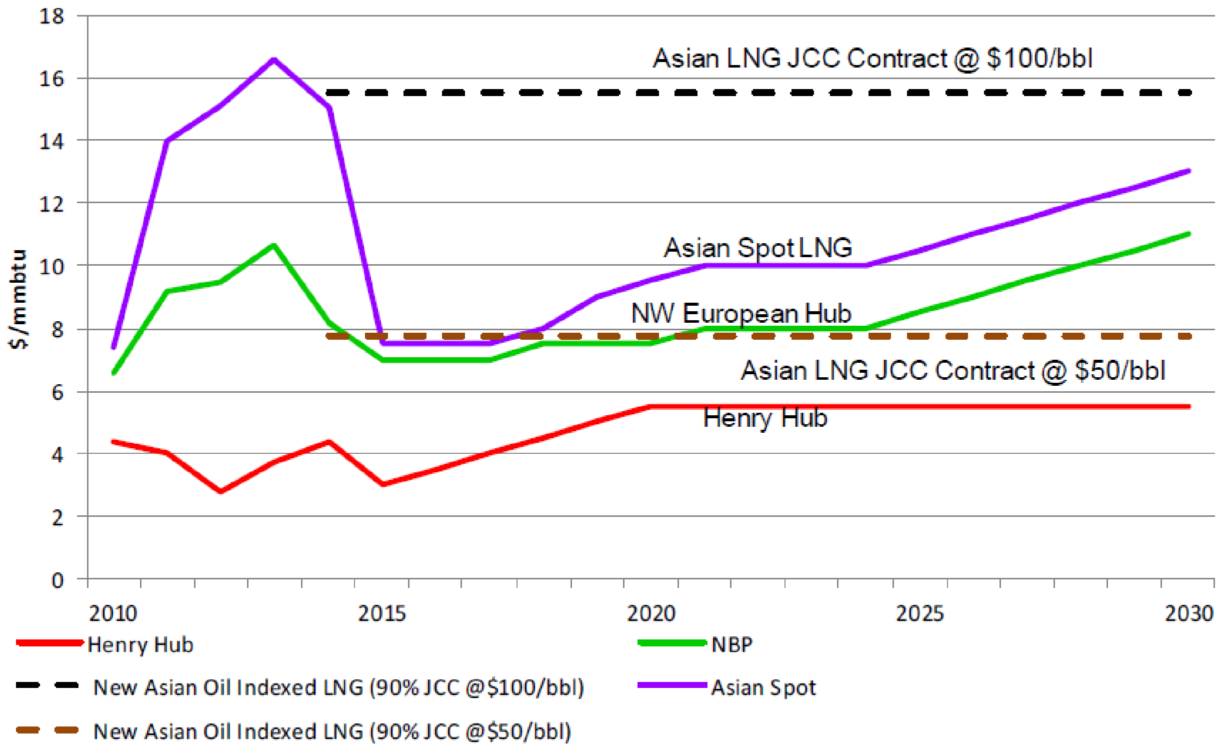
Source: LGA conversion of OIES and DoIIS BCM projections to Mtpa.

Figure 2-4 Price Projections corresponding to High LNG Demand



Source OIES

Figure 2-5 Price Projections corresponding to Low LNG Demand



Source OIES

2.1.7 Additional LNG Trains in Queensland

As noted in the previous section, for the Strong Scenario the global number of additional LNG trains required is estimated to be as for OIES High projections, which are equivalent to their 2014 projections delayed by two years. In 2014 OIES concluded that one additional Queensland train would reach FID by 2020, so by analogy, in the Strong Scenario this train may reach FID by 2022, and be in production by 2026 or 2027, at the midpoint of the projection timeframe. This is consistent with the High Scenario in the 2015 NGFR LNG Projections. LGA acknowledges that in the present weak market conditions LNG market participants may find this scenario difficult to imagine. However it should be noted that third train start-up is ten years into the future, a time frame comparable with the time that has elapsed since the Gladstone projects were first conceived.

For the Neutral Scenario the global number of additional LNG trains required is estimated to be as for OIES Low projections, which are substantially lower than their 2014 projections. The cumulative number of required trains does not exceed 20 until 2027, compared to 2022 in the High projections. By analogous reasoning to the Strong Scenario, the one additional Queensland train would not be expected to reach FID until 2027, and be in production by 2031 or 2032. LGA considers there to be no merit in considering a significant variation to the Neutral Scenario at such a distant timeframe and therefore assumes there are no additional trains in this scenario, consistent with the Base Scenario in the 2015 NGFR LNG Projections.

The Weak Scenario by definition embodies weaker incentives for additional trains than the Neutral Scenario and therefore contains no additional trains, consistent with the Low Scenario in the 2015 NGFR LNG Projections.

It is noted that DoIIS global supply projections indicate no capacity expansion in Australia (and therefore in Queensland as well) from 2018 to 2030, consistent with the Neutral Scenario assumptions above.

2.1.8 LNG pricing

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

LNG price = α* JCC + β

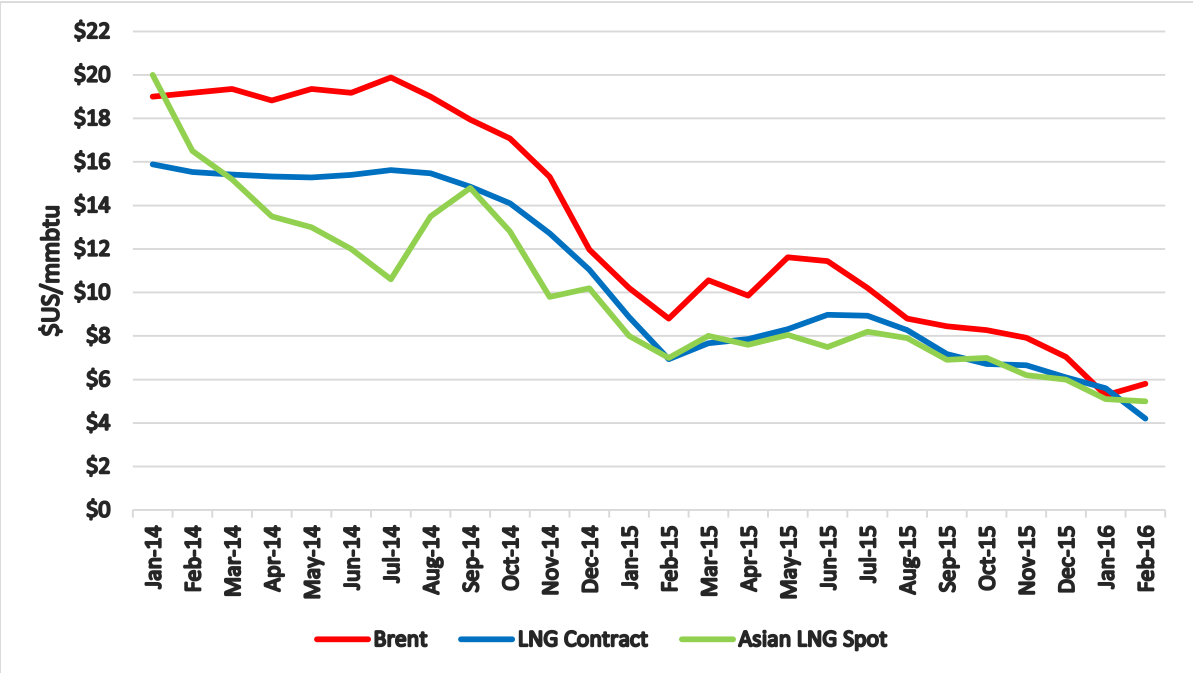
In this formula the LNG price is expressed in $US/mmbtu and JCC is the Japan Customs Cleared crude price, also nicknamed the Japan Crude Cocktail, expressed in $US/bbl and typically a six to nine month lagged version of the Brent Crude oil price. α and β are constants that are set during the contract 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 α 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 β. An average of slope of 0.14 is assumed, together with a constant of zero. To the best of LGA's knowledge the price applies on a free-on-board basis, that is, the shipping cost accrues to the buyer.

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 $US40/bbl (Figure 2-6), at which the LNG contract price is just $US5.60/mmbtu, well below long-run costs and illustrating the high risks involved in oil indexed pricing. Asian spot LNG prices have also fallen, to similar values, 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 less volatile pricing model, with prices expected to remain the band between $US10/mmbtu and $US12/mmbtu. At the time oil was priced at $US100/bbl, this model was very attractive to Japanese buyers but the attraction has since faded.

Figure 2-6 Falling oil and LNG prices



Sources: Brent – Investing.com; JCC/LNG Contract – Japanese Ministry of Finance; LNG Spot – Timera-Energy.com

Contract prices and netback values in each of the AEMO Scenarios are presented in Table 2-5.

Table 2-5 LNG prices and netbacks in the AEMO Scenarios

	Strong Scenario	Neutral Scenario	Weak Scenario
Brent/JCC ($US/bbl)	$90.00	$60.00	$30.00
$A/$US Exchange Rate	0.95	0.75	0.65
LNG Contract FOB ($US/mmbtu)	$12.60	$8.40	$4.20
LNG Contract FOB ($A/GJ)	$12.56	$10.61	$6.12
Short Run Opex ($A/GJ)	$1.00	$1.00	$1.00
Short Run Netback $A/GJ	$11.56	$9.61	$5.12

Further analysis of the influence of these factors is presented in Appendix A.

2.2 Scenario selection

The number of LNG trains in each scenario is summarised in section 2.1.7. This section develops the rationale for the utilisation rates of the trains in each scenario. As in the 2015 NGFR LNG Projections, the utilisation rate is assumed to correlate with oil/LNG prices, higher prices are assumed to be due to higher global demand, which, other things being equal, leads to higher utilisation.

In all scenarios it is most likely that LNG production will vary from time to time but such variations are at best unpredictable and at worst will confuse the interpretation of scenario outputs. Consequently the annual production levels are generally held constant over long periods of time.

2.2.1 Strong Scenario

LNG market conditions in this scenario provide strong incentives for LNG production to be maximised, namely high prices and strong LNG demand. Recent production at QCLNG and GLNG has been at 110% and more of nameplate capacity (please refer to section 3.7 for details), equivalent to 4,529 TJ/d for all six existing trains. This is slightly greater than combined pipeline capacity of 4,520 TJ/d but significantly greater than planned gas supply of 4,259 TJ/d excluding underground storage, which only contributes to ramp-up and peak supply (refer to section 3.7). Consequently it appears that aggregate production will initially be limited to 100% of nameplate capacity by supply constraints.

Market conditions would provide incentives for incremental supply to be developed to overcome these constraints, hence in this scenario it is assumed that the six existing trains all operate at 105% of nameplate capacity from 2021. The 105% figure allows for 5% outages for maintenance and is equivalent to approximately 112% of contracted output, 2% higher than the level assumed in the 2015 NGFR LNG Projections.

The 7th train constructed in this scenario (3rd train at QCLNG) operates at a similar level from 2027. Pipeline capacity is expanded by construction of a mid-line compressor station on the QCLNG pipeline.

2.2.2 Neutral Scenario

To distinguish the Neutral Scenario from the Strong Scenario it is appropriate for LNG production in the Neutral Scenario to be at the level of the agreed supply contracts. This is the same as in the 2015 NGFR LNG Projections and implies than any changes in scenario outputs are due to changes in other assumptions or methodology.

It is important to note that market conditions in this scenario, i.e. the value of the LNG netback, provide strong incentives for ongoing development of replacement gas supply, in the form of drilling additional wells and developing new fields to maintain supply capacity as the production from initial wells declines.

2.2.3 Weak Scenario

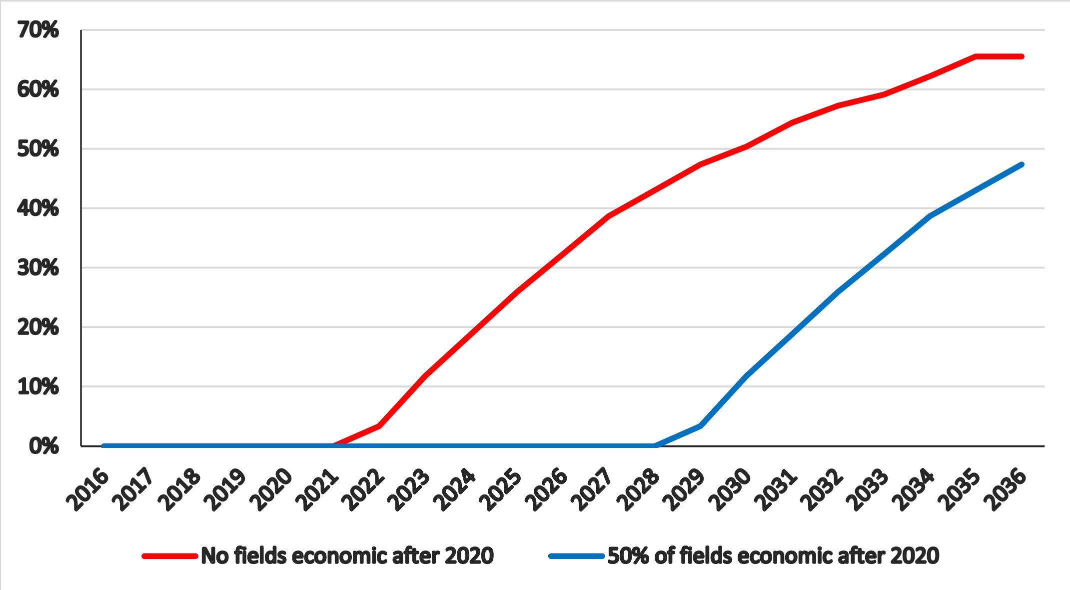
The Weak Scenario is characterised by weak global LNG demand and, more importantly in the long run, weak incentives for ongoing development of replacement gas supply. Weak demand will probably result in buyers reducing their contractual offtake down to take-or-pay levels, which for consistency with the 2015 NGFR LNG Projections is assumed to be 85%.

The short-run netback value has to be greater than the cost of development of replacement gas supply for this development to be justified. The low netback in this scenario, $5.12/GJ, will almost certainly preclude some such developments occurring. The drilling of additional wells in existing fields will most likely be justified but new field developments, involving new processing plants and interconnecting pipelines, are less likely, particularly as many of the lower cost fields have been developed first, leaving higher cost options for later.

Decisions not to develop the replacement capacity would be problematic, as they would leave the operator unable to meet demand in the event of an improvement in conditions. Even if current conditions prevail for the next two to three years, i.e. the Weak Scenario starts to play out, investment decisions are likely to continue to be made on the basis of conditions improving to Neutral and only when the Weak Scenario is well established would decisions not to develop replacement capacity be made.

A measure of the impact of not developing replacement capacity has been obtained from Figure 13 of Reference 1, which illustrates APLNG's gas supply on a field by field basis. If it is assumed that no new field developments start up after 2020, then by 2025 supply declines by 26%, by 2030 it declines by 50% and by 2036 it has declined by 66%. If it is assumed that half of new developments required between 2020 and 2036 remain economic, these will be developed from 2020 until none remain, so that supply doesn't start to decline until 2029. The two supply decline profiles discussed here are depicted in Figure 2-7.

Figure 2-7 Weak Scenario gas supply reduction due to non-replacement of capacity lost



In section A.1.3 it is estimated that the long run marginal cost of incremental production is $5/GJ. In the absence of cost data applicable to individual fields it is assumed that half of new developments would come in below this figure and would therefore economic given a netback of $5.12/GJ in this scenario, hence the 50% economic scenario applies. The relevant percentage reductions in supply are applied to all CSG supply, for all projects.

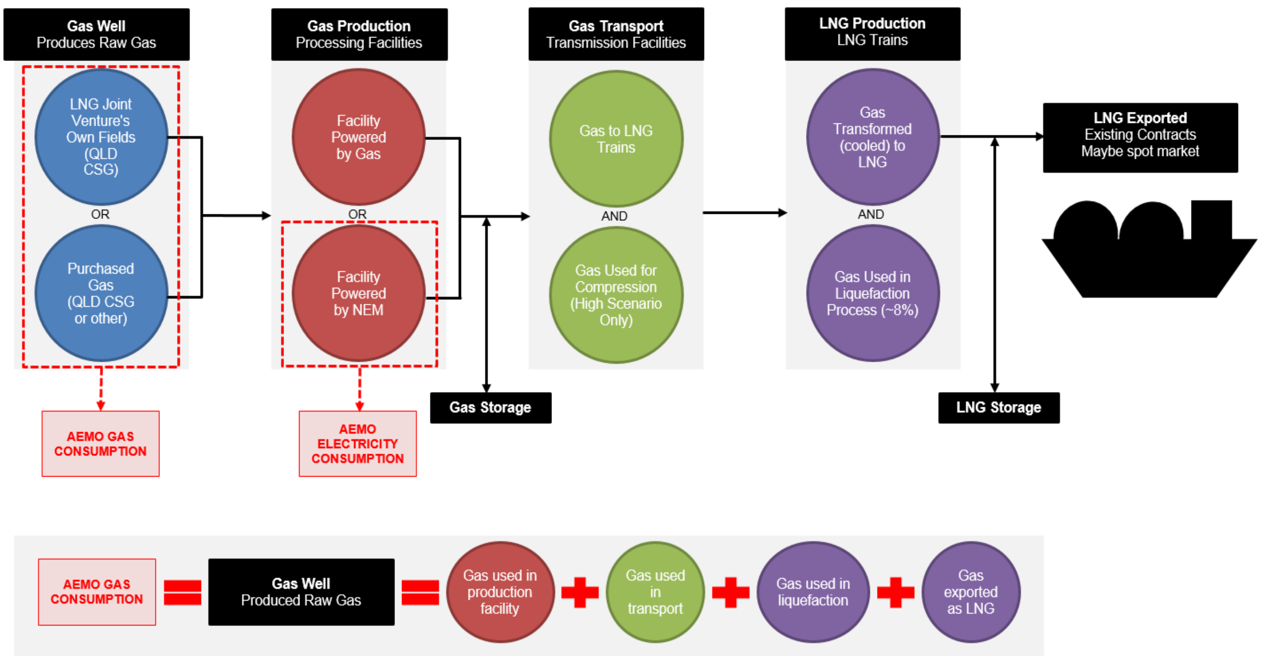
This scenario also incorporates delays to start-up of the GLNG and APLNG 2nd trains, and a slower ramp-up to plateau production.

3. Gas and Electricity Usage Methodology

3.1 Overview

The gas supply chain from wellhead to export and the relevant components of each link 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 an updated and improved version of the methodology applied to prepare the 2015 projections. The projection logic models the supply chain backwards, from right to left in the above diagram. Starting with the selected export volume scenario, 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 at the same point in the chain, no assumptions are made regarding the ultimate energy source from which the electricity was derived and consequently there are no multiplier effects as there are for gas.

The 2015 and some earlier projections took explicit account of the production of ramp gas prior to LNG production[22]. However as the CSG fields are now collectively producing at more than 50% of their ultimate production levels, the ramping up of additional fields can be managed by turning down the existing ones, so that ramp gas ceases to be an issue and it is not considered in this report.

[22] CSG wells cannot be brought on-line instantaneously and instead have to be ramped up to full production

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 2015 projections; and AEMO information on gas and electricity consumption related to the LNG projects.

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 Weak Scenario.

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 3.12. Revised maximum demand models have been developed for the 2016 NEFR.

Table 3-1 The LNG supply chain

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

3.1.1 Historical data

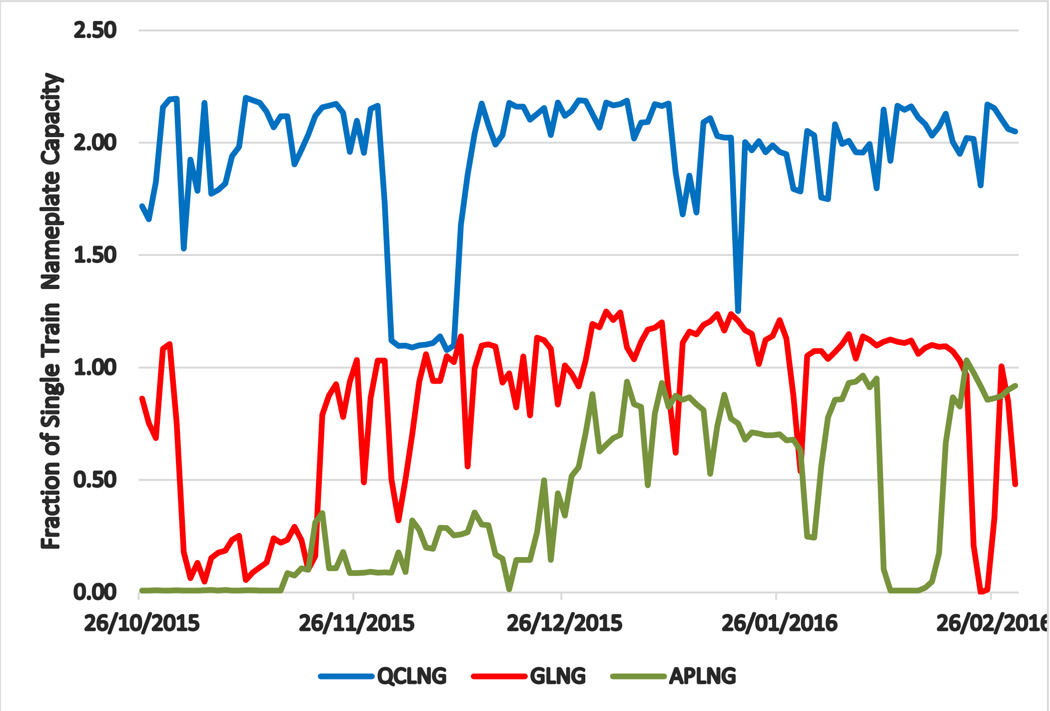
3.1.1.1 Exports

QCLNG started liquefaction in late December 2014 and shipped the first LNG cargo from Gladstone on the 5th January 2015. Estimates of LNG production rates were initially based on CSG production and the number of cargoes shipped but since October 2015 the AEMO Bulletin Board has reported gas flows on the LNG pipelines, equivalent to gas exported plus gas used in liquefaction.

[23] Future Curtis Island LNG facilities could be connected to the NEM via a cable connection
[24] 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.

Figure 3-2 shows LNG production rates for each plant since October 2015, expressed as fractions of a single train capacities. Since it shut down one train in early December, QCLNG has operated both trains at capacity on average and has regularly operated up to 10% above capacity. GLNG has likewise operated its single operational train above nameplate capacity, reaching 120% of capacity from time to time. APLNG appears to be starting up more conservatively, with its production reaching 100% of capacity shortly after its first train shut for maintenance in February but generally operating below this level.

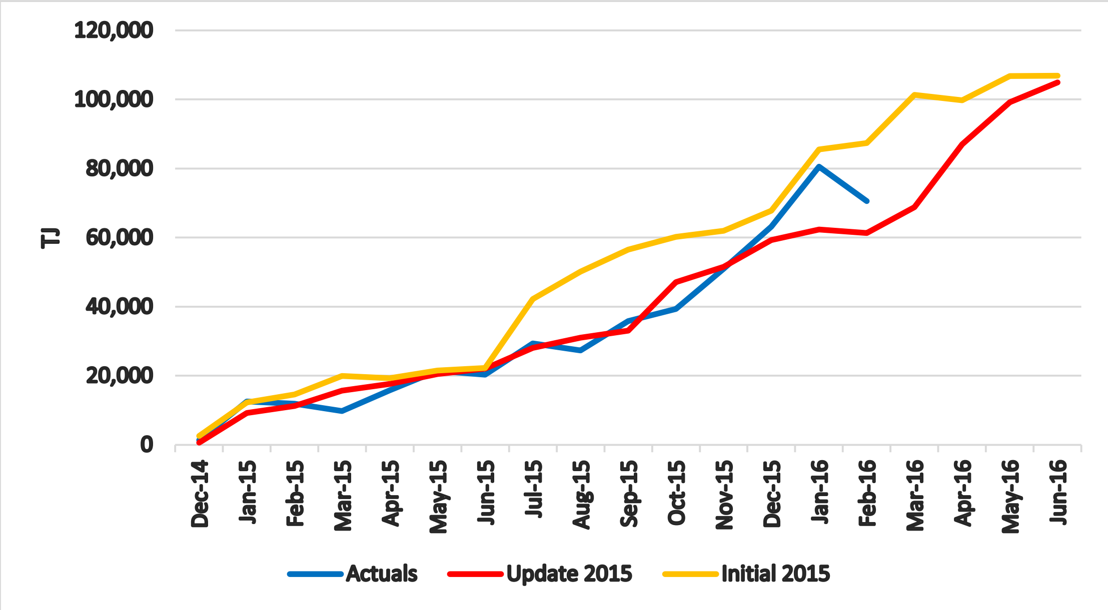
Figure 3-2 Daily LNG production (fraction of single train nameplate capacity)



Source: AEMO Bulletin Board

Figure 3-3 compares LGA's 2015 aggregate monthly projections with actual production to date. January production exceeded the Update projection because all four operating trains were operating close to capacity, whereas the projections assumed significant time out for maintenance in the early stages of operation for GLNG and APLNG. The February actuals reflect this assumption more closely.

Figure 3-3 Projected vs estimated actual gas used for LNG (TJ/month)

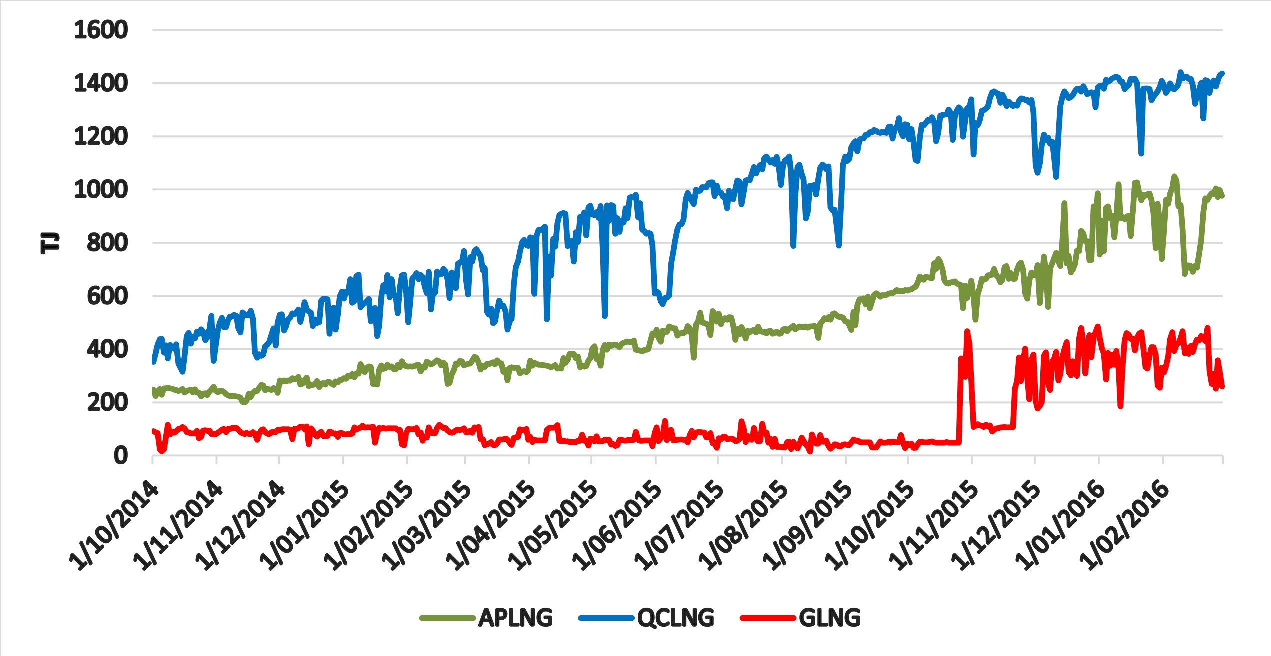


Source: LGA projections and estimated actuals

3.1.1.2 Gas production

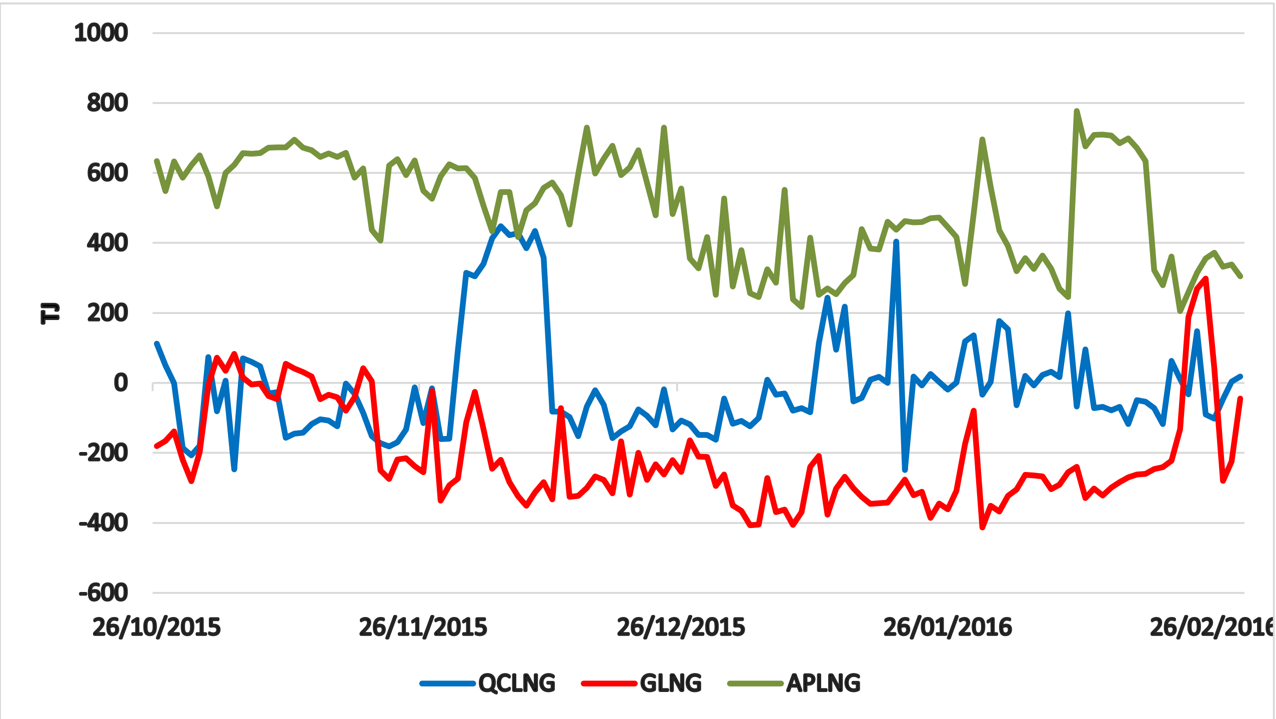
Reported production of CSG by the three projects since October 2014 is shown in Figure 3-4.This clearly shows QCLNG production ramping up from 400 TJ/d to 1400 TJ/d consistent with steady growth of LNG production, with a number of major shutdowns. APLNG's production ramped up to 600 TJ/d prior to commencement of its first LNG train and up to 1000 TJ/d since LNG production started. GLNG however did not ramp up prior to LNG production and is producing less CSG than it is using for LNG production (Figure 3-5), which is consistent with its known reliance on third party gas.

Figure 3-4 Daily CSG production



Source: AEMO Gas Bulletin Board

Figure 3-5 Net CSG production less LNG usage



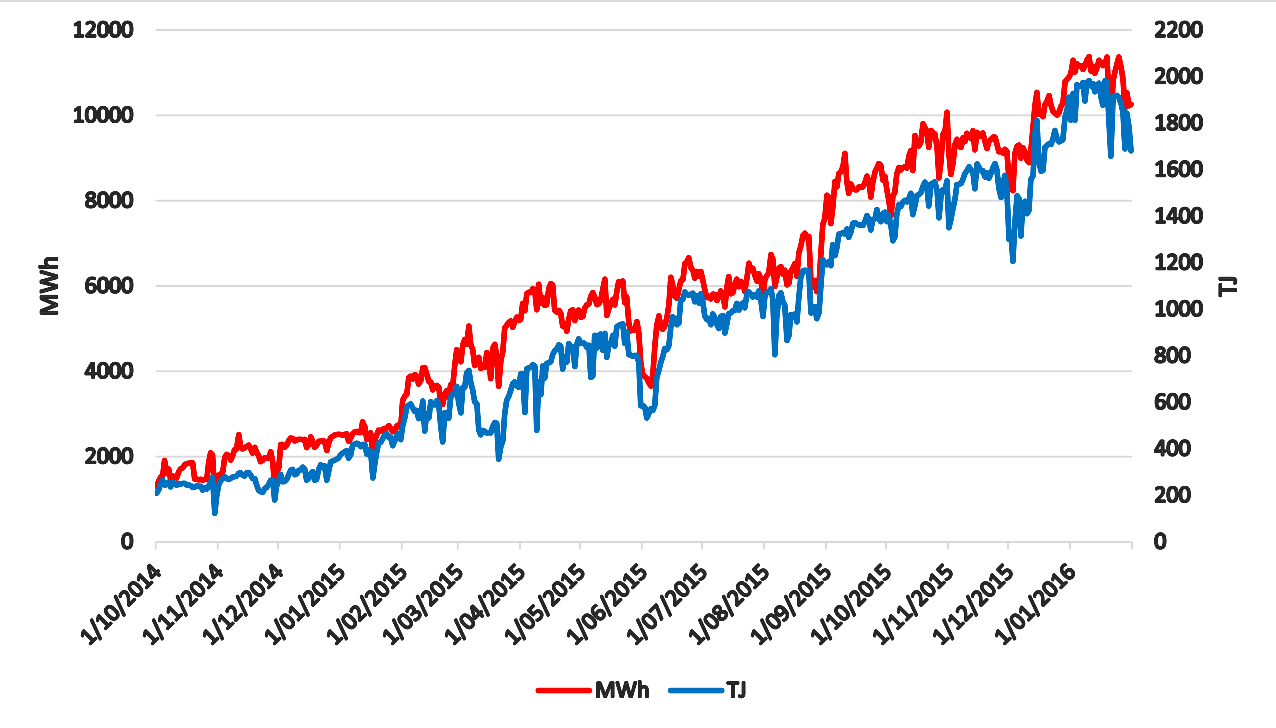
Source: AEMO Gas Bulletin Board

Total CSG production reached over 2800 TJ/d during January 2016, approximately equivalent to the requirements for the four LNG trains in operation. The individual peaks for each CSG plant up to January 2016 add to almost 3600 TJ/d and the total capacity of the existing plants, as registered on the AEMO Bulletin Board, is 4472 TJ/d. Plant construction and well-drilling are reported as complete but many wells have yet to be connected and de-watered.

3.1.1.3 Electricity usage

Aggregate electricity usage by the LNG projects to date is presented in Figure 3-6 together with gas produced at plants with electrically driven compressors. Electricity use has grown to 11,400 MWh/day (an average of 475 MW). The chart also shows a clear correlation of electricity use with gas production, though with periods during which gas production is relatively lower. Use of this data to derive estimates of electricity usage per unit of gas produced is described in section 3.6.3.

Figure 3-6 Aggregate daily electricity usage vs aggregate electricity powered gas production



Source: AEMO and Gas Bulletin Board, LGA analysis

3.2 Gas exported

The assumed plateau export levels in each scenario are summarised in Table 3-2.The Neutral 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 Neutral Scenario, the exports in the Neutral and Strong Scenarios can be assumed to extend to at least 2036. 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. The Neutral and Strong Scenarios are therefore assumed to extend past 2041.

In the Weak Scenario the inability to invest in replacement CSG production capacity leads to a decline in CSG production and LNG exports from 2030.

Table 3-2 Plateau export levels (Mtpa)

Scenario	QCLNG	GLNG	APLNG	QCLNG T3
Strong	8.9	8.2	9.5	4.5
Neutral	8.0	7.2	8.6	Not applicable
Weak	6.8	6.1	7.3	Not applicable

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

- The Neutral Scenario is LGA's interpretation of most recent timing statements by projects:
  - QCLNG[25]: Train 1 (T1) started in December 2014 and reached commercial production in Quarter 2 (Q2) 2015; T2 started up July 2015 and reached commercial production in November 2015. However Shell has stated that plateau production may not be reached until mid-2016.
  - GLNG[26]: T1 started in September 2015 (effectively Q4 CY 2015), and is expected to become commercial over 3-6 months; T2 to produce first LNG in Q2 CY 2016[27] and ramp up over 2-3 years
  - APLNG[28]: T1 started in December 2015 (effectively Q1 CY 2016) and became commercial in March 2016; T2 six months later start up and sustained production
- Strong 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 initial 100% of name plate capacity. The increase to 105% of nameplate capacity occurs in 2021 for all plants.
- Weak Scenario: First LNG and plateau are delayed relative to Neutral Scenario for all elements except QCLNG T1. This would be consistent with minor technical problems prior to or during start-up.

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. The data now available for GLNG indicates that for its first 90 days (a full calendar quarter is not yet available) LNG production averaged 80% of capacity and 87% of contracted sales. For APLNG during the 2 months since first LNG production on December 11 2015, LNG production averaged 55% of capacity and 58% of contracted sales. Figures consistent with these levels are used in the 2016 Projections. (It is noted that accurate figures for initial production by QCLNG are not available as the relevant periods predated the figures being published on the Bulletin Board. This is not a concern however as QCLNG is already close to full production.)

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

26 Cooper and GLNG Investor Visit (20-23 April 2015)

27 Fourth Quarter Activities Report, Santos, 22 January 2016

28 ORG Macquarie Conference Presentation May 5 2015

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

	QCLNG				GLNG				APLNG			
	T1		T2		T1		T2		T1		T2	
	Actual Start	Actual Plat	Actual Start	Plat	Actual Start	Plat	Start	Plat	Actual Start	Plat	Start	Plat
Strong	Q4 14	Q2 15	Q3 15	Q2 16	Q4 15	Q2 16	Q2 16	Q4 17	Q1 16	Q3 16	Q2 16	Q4 16
Neutral	Q4 14	Q2 15	Q3 15	Q2 16	Q4 15	Q2 16	Q2 16	Q3 18	Q1 16	Q3 16	Q2 16	Q1 17
Weak	Q4 14	Q2 15	Q3 15	Q4 16	Q4 15	Q3 16	Q4 16	Q3 19	Q1 16	Q4 16	Q4 16	Q3 17

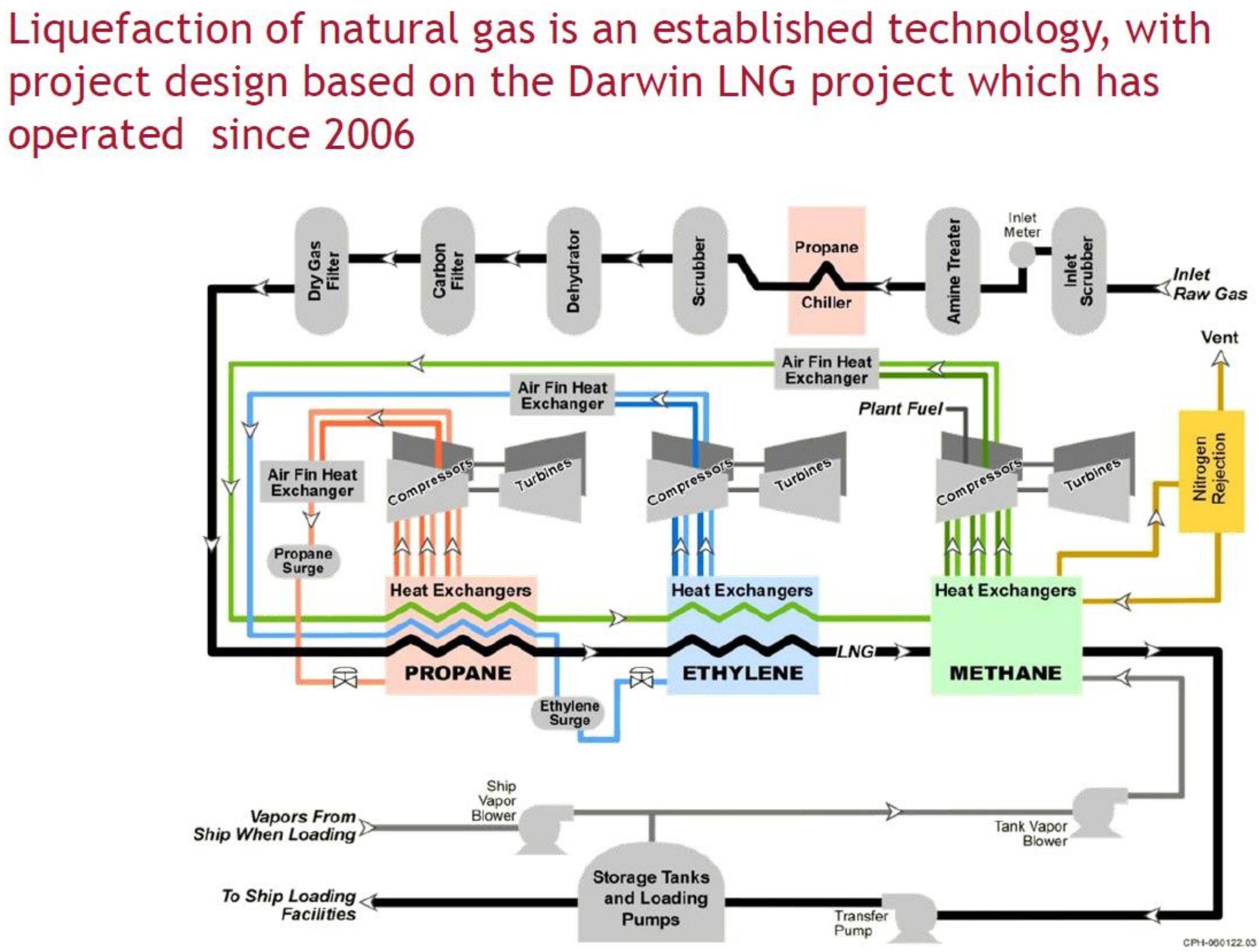
Notes: T1 = Train 1 first gas exported; T2 = Train 2 first gas exported; Plat = Plateau production reached for each train; Q1 = first quarter of the calendar year etc.

3.3 Energy used in LNG production (liquefaction)

3.3.1 Energy sources

In the 2015 Projections it was 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 have been 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 3-7) indicates that the same applies to the Gladstone plants. Consequently LGA considered that the Gladstone plants would be gas fuelled and use no grid electricity. No subsequent evidence contradicts this assumption.

Figure 3-7 APLNG Liquefaction plant Outline



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 -161C. Reference 1 suggests that 10TJ/d is an appropriate figure for testing gas usage and this figure is retained in the 2016 Projections, for application to the GLNG and APLNG second trains.

3.3.3 Liquefaction gas usage

Reference 1 states an LNG plant efficiency target of 92.6%. Since all three plants use the same technology, this figure is used for all plants in this projection.

Reference 1 also notes that the efficiency has considerable seasonal variation, ranging from 90% in winter to 94.6% in summer. This has been incorporated in the projections, which are calculated on a quarterly basis, by using the summer efficiency in Q1, the winter efficiency in Q3 and the average efficiency in Q2 and Q4. This results in seasonal variations in gas and electricity usage and different maximum demands in summer and winter.

Plant efficiency estimates can be tested using actual values of LNG production and gas usage provided by the operators. For GLNG, Santos reports that Q4 2015 LNG production was 544,000 tonnes (29.9 PJ) and the average plant feed rate was 370 TJ/d (34 PJ for the quarter), which suggests a plant efficiency of only 88%. Since the plant was operating under capacity these figures may be atypical and are not used but they will become more useful measures of efficiency in future 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 3-8 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 3-8 LNG Pipelines Map

Source: 2013 GSOO, AEMO, 29 November 2013.

Table 3-4 LNG export pipeline parameters

	QCLNG	GLNG[29]	APLNG[30]
Length Main Export PL (km)	334	420	362
Internal Diameter (mm)[31]	1,040	1,040	1,050
Maximum Operating Pressure (kPa)	10,200	10,200	13,500
Capacity without compression[32] **(TJ/d)**	1,530	1,430	1,560

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.
- Given Shell's common ownership of Arrow and QCLNG it is assumed that the 7th Train in the High Scenario becomes the 3rd Train at QCLNG and that the gas for this train is transported solely on the QCLNG pipeline, which will therefore be carrying gas for three trains, in which 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 QCLNG pipeline and we have calculated the energy required for both options.

[29] GLNG Gas Transmission Pipeline Description
[30] "Constructing the pipeline", available on www.aplng.com.au
[31] All pipes are stated to be 42 inches in diameter. The stated diameters in mm vary.
[32] Standing capacities listed on the AEMO Bulletin Board

Estimated gas compression usage for 800 TJ/d load for the additional train is 41 TJ/d (5.2% of load) for the QCLNG pipeline. The equivalent electricity usage would be 4226 MWh (1.9% of gas load). These factors are applied at all pipeline loads.

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 (100 TJ/d withdrawal), makes up less than 8% 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[33]. The principal source of these resources for each project will be their equity reserves in Queensland CSG, for which updated values are presented in Table 3-5. Total reserves have fallen by 0.3% compared to the values at 31st December 2014 used in the 2015 NGFR LNG Projections report.

GLNG and QCLNG also rely upon third party gas supplied under long term contracts. Updated estimates of gas volumes are reported in Table 3-6. Since the 2015 NGFR LNG Projections report was compiled GLNG has entered a new supply agreement with AGL. QCLNG's total contract volume is estimated to be 745 PJ and GLNG's is estimated to be 2782 PJ.

Table 3-5 LNG project equity and operated Queensland CSG reserves as at 30 June 2015 (PJ)

	Equity	Operated
QCLNG	9,902	12,108
GLNG	5,953	6,723
APLNG	14,437	11,795
Arrow Energy	9,083	10,328
Others	3,358	1,779
Total	42,733	42,733

Source: Operated - Queensland Department of Natural Resources and Mines; Equity – LGA based on ownership.

[33] 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 20th year.

Table 3-6 LNG project contracts with third party suppliers

	Seller	Operator	Buyer	Source	Delivery Point	Term (years)	Total Volume (PJ)	Annual Volume (PJ)
1	APLNG	QCLNG	QCLNG	Surat CSG	Field	20	640	95 falling to 25 after 2016
2	Santos	Santos	GLNG	Cooper primarily	Wallumbilla?	15	750	50
3	AGL	QCLNG	QCLNG	Surat CSG	Field	3	75	25
4	Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	10	365	36.5
5	Origin	Unknown	QCLNG	OE Portfolio	Wallumbilla	2	30	15
6	Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	5	100 Firm 94 Sellers option	20-39
7	Stanwell	Unknown	GLNG?	Wallumbilla?	Wallumbilla?	1.75	53	30
8	AGL	QCLNG?	GLNG	Surat CSG	Wallumbilla?	7	32	4.6
9	Meridian JV	Westside	GLNG	Bowen CSG	GLNG Pipeline	20	445	24
10	Senex	GLNG	GLNG	Surat CSG	GLNG Pipeline	20	Up to 365	Up to 18.3
11	AGL	QCLNG	GLNG	Surat CSG	Wallumbilla	11	254	Up to 34

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.

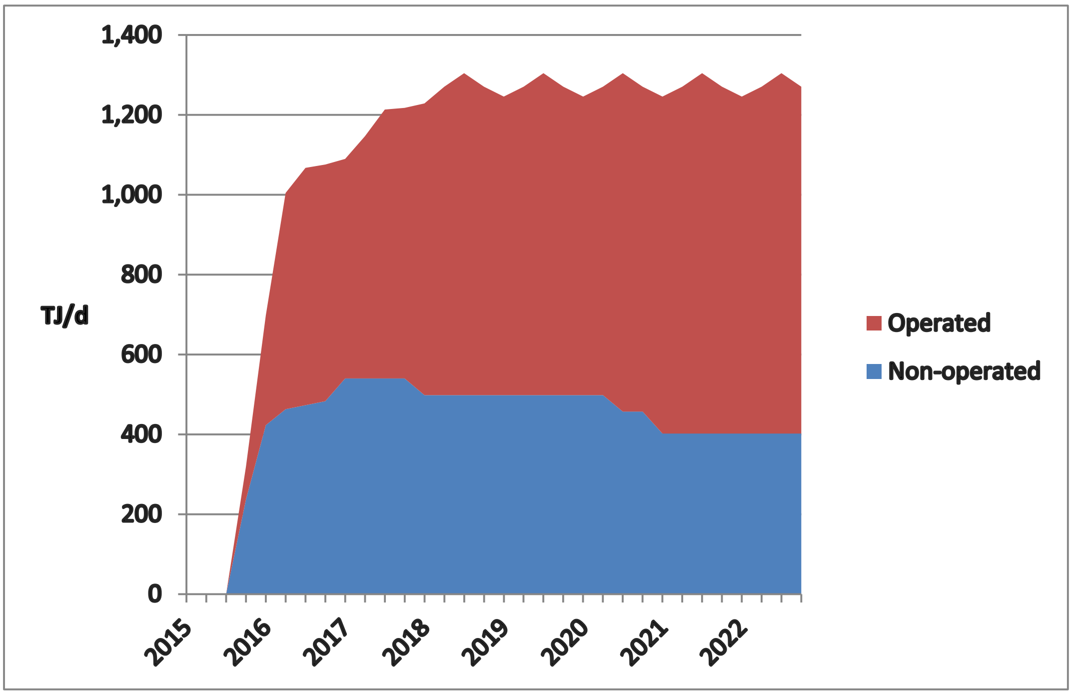
Complementary to the first contract, it has been assumed that APLNG will take 70 PJ of its equity share in the QCLNG operated fields, at the time it reaches plateau LNG production levels in 2016. There are also arrangements between GLNG and APLNG for GLNG to take approximately 12 PJ pa of equity gas at Combabula and APLNG to take 35 PJ pa of its equity gas at Fairview.

3.6.2 Supply model

For each LNG project, the gas supply contracts are separated into “operated” (contracts 1, 3 and 10 above) 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, as it is reasonable to assume the contracts all have high take-or-pay provisions. The operated gas requirement is then the LNG plant requirement, 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 3-9 illustrates the application of this approach to GLNG in the Neutral Scenario. The seasonal variations in liquefaction use (refer to section 3.6.3) are assumed to be taken up by the gas fields operated by GLNG.

Figure 3-9 GLNG Neutral Scenario gas allocation to operated and non-operated – average daily supply



3.6.3 Gas field and processing plant energy usage

3.6.3.1 Operated gas

The primary energy requirements are for field and plant gas compression, with lower requirements for auxiliaries including water pumping and desalination. Following discussions with LNG project representatives in conjunction with AEMO, LGA has a clearer understanding of how these functions will be powered:

- All three projects are using electric drive compressors at their gas processing plants for most of their new developments. APLNG plans to use gas engines at some of its smaller, as yet to be constructed, processing plants (Reference 1).
- For new wells GLNG is using electric compression at the well head whereas QCLNG and APLNG are using gas engines.
- All electricity for the above will ultimately be sourced from the Queensland electricity grid.
    - For QCLNG connection occurred prior to 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. Construction of the grid connection was scheduled to be completed by the end of 2015 and a Powerlink project status report in August 2015[34] suggests this target was met and the connection was partly energised. However AEMO data for January 2016 shows no power consumption at the GLNG NMI's and for the purpose of this projection it is assumed that connection will be effective from Q2 2016, with Fairview powered by the local GTs using GLNG gas until Q1 2016 inclusive.

- On 28th 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. AEMO data suggests that by Q1 2016 both of these plants were connected and using gas for all their compression requirements.

- All existing gas powered plant will remain gas powered.

The proportions of electricity and gas powered compression at processing plants in the initial phase of LNG production (circa 2017-2018) has been estimated assuming that domestic loads are met from existing gas powered plants, because these are already connected to domestic pipelines (Table 3-7). For QCLNG and GLNG, over time, as the initial well productivity declines and new wells and processing plants are constructed, which will be mainly electricity driven, the electricity powered proportion will increase. For QCLNG there will be a relatively sharp increase in electricity usage when the Charlie gas field development, which will feed into the Woleebee Creek gas plant, comes on line in 2018. For APLNG however, because some new plants will be gas driven, the electricity powered proportion may decline.

Table 3-7 Initial proportions of gas and electricity powered compression at processing plants

	QCLNG	GLNG	APLNG
Gas Powered	13%	8%	0%
Electricity Powered	87%	92%	100%

Source: LGA estimates, assuming domestic markets are supplied from gas powered plant.

Aggregate energy usage for compression and auxiliaries (gas and electric driven) has been estimated using a combination of:

- For gas driven plant, historical CSG plant usage figures published by the Queensland Department of Natural Resources and Mines;

- For electric plant, correlations between CSG plant usage and electricity consumption figures provided to LGA by AEMO.

For gas-driven plant the values in Table 3-8 have been re-estimated using the most recent available data, for the two years from June 2013 to June 2015. The values expressed as a % of net gas produced have changed by just 0.1% from those in the 2015 NGFR LNG Projections Report. This is equivalent to a 2% reduction in gas usage.

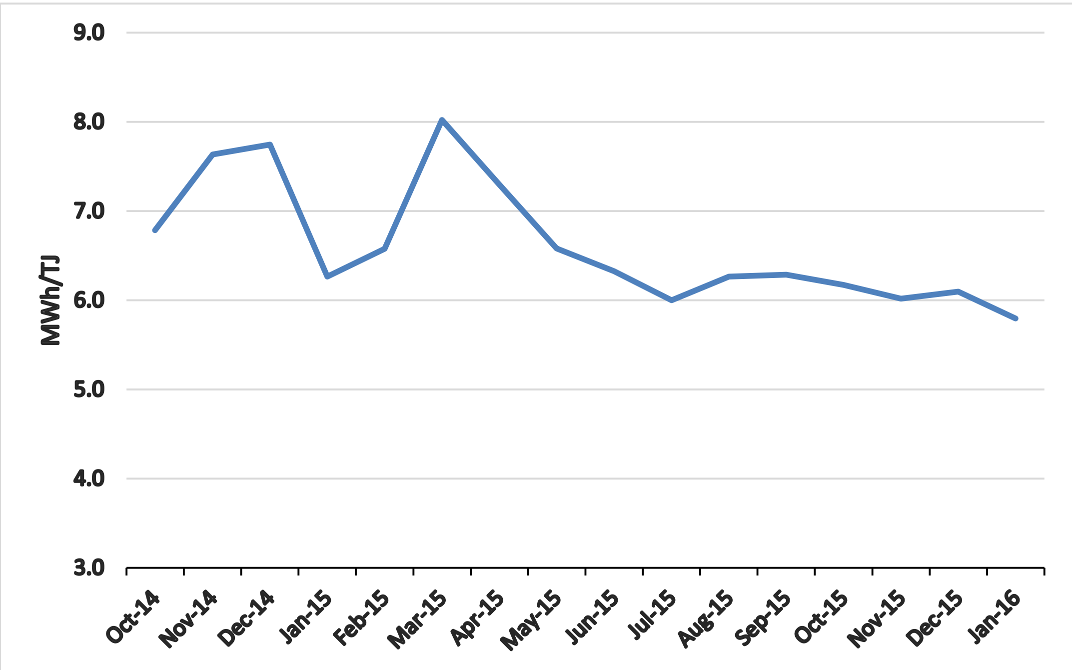
[34] North West Surat Project Update, Powerlink, 11 August 2015.

For energy usage from electrically driven plant AEMO has provided LGA with updated actual electricity usage data for the period October 2014 to January 2016 from all operating gas fields with grid powered compression. Electricity usage per unit of gas production in these fields (in aggregate) has trended downwards since March 2015 as gas production has risen (Figure 3-10). Analysis of daily electricity usage plotted against daily gas production (Figure 3-11) suggests that the current value of 5.8 MWh/TJ is a reasonable estimate of the lower bound of usage, towards which it is expected that usage will converge. This is 6.5% (0.4 MWh/TJ) lower than the estimate used in the 2015 NGFR LNG Projections Report. This figure converts to 2.09% of energy produced.

The above electricity usage covers only the processing plant compression and well head energy is provided by gas for QCLNG and APLNG. Reference 1 states that this additional gas use is equivalent to 1% of gas produced and this figure is used in the projections.

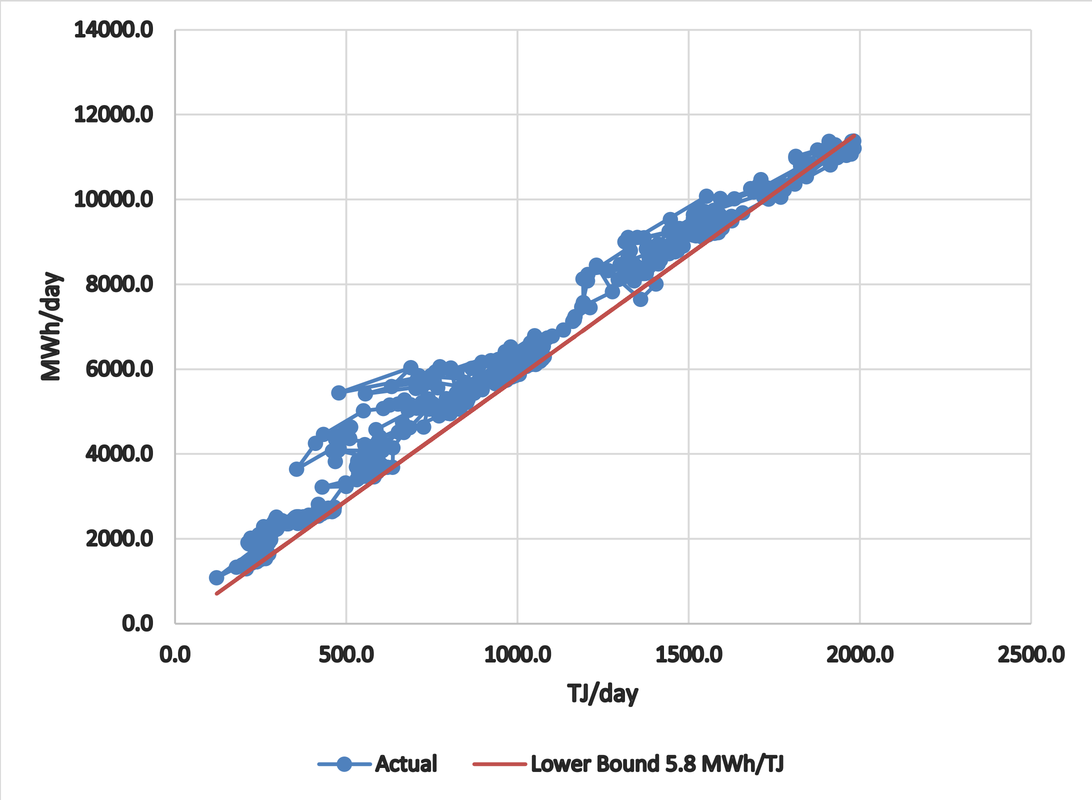
For GLNG it is reasonable to expect that processing plant electricity usage will be the same as for the other projects, and that well head usage will be the electricity equivalent of the above 1% for gas driven well heads i.e. 0.37% of energy produced. This makes GLNG's total electricity usage 2.46% of energy produced, which is reflected in Table 3-8.

Figure 3-10 Electricity usage per unit of gas production, aggregate of fields in production (MWh/TJ)



Sources: AEMO, Gas Bulletin Board

Figure 3-11 Aggregate daily electricity usage vs gas production



Sources: AEMO, Gas Bulletin Board

Table 3-8 Energy used in gas production (% of net gas energy produced)

		QCLNG	GLNG	APLNG
Gas driven plant	Gas	5.0%	6.5%	6.5%
Electricity driven plant	Electricity	2.09%	2.46%	2.09%
Electricity driven plant	Gas	1%	0%	1%

Sources: Queensland Department of Natural Resources and Mines; AEMO; Reference 1

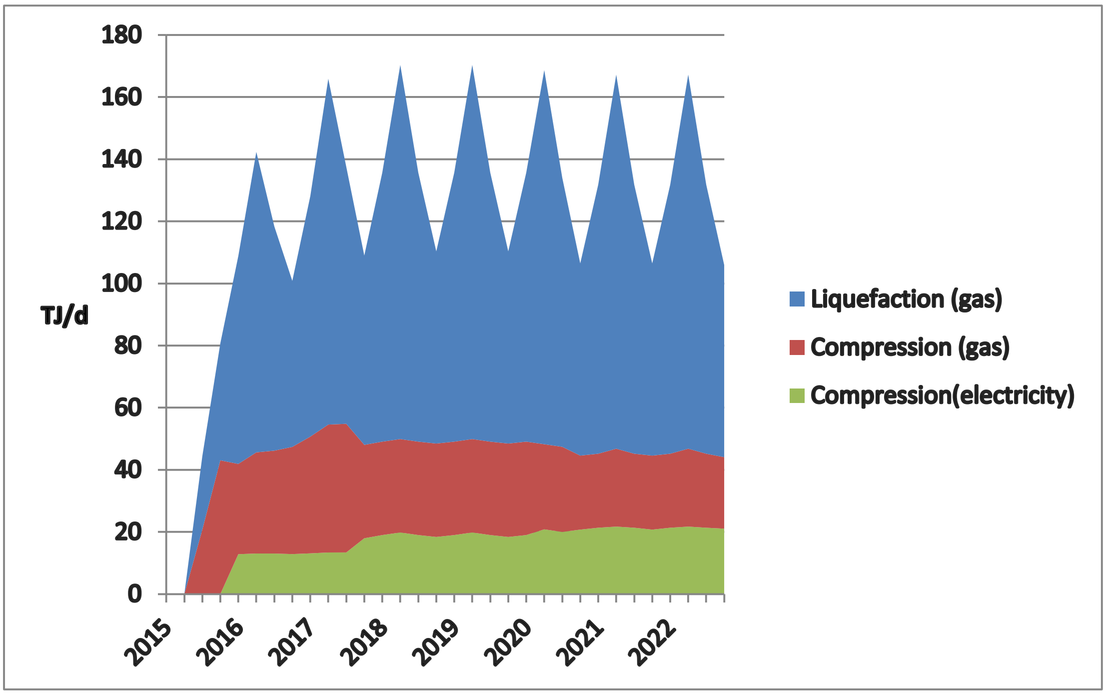
3.6.3.2 Non-operated gas

It has been assumed that all non-operated gas is non-grid connected and gas driven, with gas requirements set at 6.5% of net production, as for GLNG and APLNG above. This has not changed since the 2015 NGFR LNG Projections report.

3.6.4 Total energy usage

The total Neutral Scenario energy usage projection for GLNG is shown in Figure 3-12. The total usage falls slightly at the end of 2019 owing to a switch from gas to electrically driven compression, reflecting the lower energy requirement of electric compression, though this is largely concealed by the seasonality of liquefaction use.

Figure 3-12 Projected GLNG Neutral Scenario total energy usage



3.7 Estimates of peak gas and electricity demand

3.7.1 Peak gas demand

Peak gas demand by an LNG plant is constrained by its processing capacity and gas availability.

Regardless of the number of cargoes scheduled, an LNG plant is capable of operating up to its capacity at any time and the first four months of Bulletin Board data on LNG pipeline volumes demonstrates this very clearly. As reported in Table 3-9, QCLNG's gas demand to date for its two trains has peaked each month at 110% of nameplate plant capacity[35][36], in energy terms 1510-1520 TJ/d including gas used in liquefaction, while its load factor (average demand/peak demand) has varied between 76% and 92%. It is noted that QCLNG's peak utilisation is slightly less than its name plate pipeline capacity of 1530 TJ/d.

GLNG's gas demand for its single operating train similarly peaks in excess of nameplate plant capacity even though its load factor has varied between only 15% and 88% and APLNG's peak for its single operating train has reached 94% of nameplate capacity while its load factor has varied between 19% and 77%.

[35] Nameplate capacities in MT terms are listed in Table 2-3
[36] It is common for LNG plants' actual capacities to exceed their nameplate capacities by 10-20%.

Table 3-9 LNG project actual demand patterns

	QCLNG		GLNG		APLNG	
Period	**Load Factor %**	**Peak % Nameplate**	**Load Factor %**	**Peak % Nameplate**	**Load Factor %**	**Peak % Nameplate**
Oct-15	76%	110%	15%	110%	19%	1%
Nov-15	92%	110%	39%	103%	20%	35%
Dec-15	81%	109%	78%	119%	34%	88%
Jan-16	91%	109%	88%	125%	77%	94%
Feb-16	93%	109%	80%	115%	60%	103%
Average	87%	109%	71%	116%	57%	95%

Note: GLNG averages are for Nov-Feb and APLNG averages are for Dec-Feb.

On the gas supply side, Table 3-10 details peak supply that: a) has been demonstrated up to January 2016, i.e. the Roma Zone is the sum of the maxima produced by each Roma Zone plant independently; b) is planned capacity at existing plants, according to Bulletin Board data; c) includes capacity at planned plants under construction, including those of Meridian (65 TJ/d) and Senex (50 JT/d), which are assumed to be available from 01 January 2018.

Table 3-10 Queensland Peak Gas Supply (TJ/d)

	Roma Zone	**SWQP**	**Silver Springs**	**Roma Storage**	**Gross Supply**
Demonstrated at 31-02-2016	3,594	250	40	100	3,984
Existing Plant at Planned Capacity, available 01-07-2016	4,532	250	40	100	4,922
Planned Plant at Capacity, available 01-01-2018	4,647	250	40	100	5,037

The net peak supply available for LNG, assuming no curtailment of Queensland pipeline load (Carpentaria, RBP and GGP, which have a total co-incident peak load of 438 TJ/d) nor of CSG-direct connected GPGs, is detailed in Table 3-11. It is noted that the total nameplate pipeline capacity, which by virtue of interconnections is effectively shared among the projects, is 4,520 TJ/d, which is greater than the planned gas plant capacity and would therefore not be a constraining factor on peak demand.

Table 3-11 Net peak gas supply available for LNG (TJ/d)

		# LNG Trains Supplied at	
	Net Peak Supply (TJ/d)	110%of nameplate capacity	100%of nameplate capacity
Demonstrated at 31-01-2016	3,283	4.3	4.7
Existing Plant at Planned Capacity, available 01-07-2016	4,284	5.6	6.2
Planned Plant at Capacity, available 01-01-2018	4,399	5.7	6.3

The table also illustrates the approximate number of LNG trains that can operate at 110% or 100% of nameplate capacity, with 100% co-incidence of peaks, for each supply situation. During the past four months the four operating trains appear to have operated without any gas supply constraints but when the remaining GLNG and APLNG trains become operational over the next few months this situation will change. From Q3 2016 onwards, 110% capacity LNG peaks will only be supported if either 200TJ/d of Queensland domestic load is curtailed or the LNG peaks are only 95% co-incident i.e. their combined peak is 95% of the sum of their individual peaks. Coincidence is currently running at 97-98%.

For the purposes of the Neutral Scenario projections it is assumed that the individual plant peaks remain at 110% of nameplate capacity and that coincidence reduces to 95% from Q3 2016. For the Strong Scenario, with higher levels of aggregate production, coincidence must be set at 100% and the underlying assumption must be that some domestic load is curtailed, or additional gas production capacity is constructed.

In the Weak Scenario it is assumed that when LNG production starts to decline due to non-replacement of CSG capacity, LNG trains are progressively mothballed, which leads to reductions in peak demand. It is also noted that the plateau production from 2020 to 2030 in this scenario could be met by five trains, i.e. that one train could be mothballed, but this has not been assumed.

It is noted that the above estimates are viewed as 1-in-2 POE peaks. Currently available data is insufficient to determine 1-in-20 POE peaks, however based on the above methodology, 1-in-20 POE peaks may not be significantly higher than the 1-in-2 POE peaks.

3.7.2 Peak electricity demand

Electricity demand is determined by compression requirements in the electrically compressed gas plants. For aggregate electricity demand, a linear relationship between gas produced in these plants and electricity demand has been derived (refer to section 3.6.3).

To estimate peak electricity demand, two further aspects of gas and electricity use must be investigated:

- Is the proportion of gas supplied by electrically compressed gas plants the same on peak demand days as on average days?

Given that the electrically compressed plants supply the majority of gas for LNG, this is likely to be the case. Examination of gas production data from December 2015 and February 2016 confirms that the peak day and average day proportions differ by less than 1%.

- What is the hourly load factor of electricity demand on the peak gas demand day?

  Examination of electricity usage data for December 2015 and January 2016 indicates that daily load factors have limited variation, from 95% to 99%, and averaged 97% for the period. A load factor of 97% has therefore been assumed.

It is noted that the above estimates are viewed as 1-in-2 POE peaks. Currently available data is insufficient to determine 1-in-10 POE peaks, however based on the above methodology, 1-in-10 POE peaks may not be significantly higher than the 1-in-2 POE peaks.

3.8 Minimum gas and electricity demand

Minimum LNG production, gas demand and electricity demand will occur during LNG plant outages, whether for planned maintenance or due to unplanned incidents. The LNG projects have collectively applied[37] to the ACCC for approval of co-ordination of planned maintenance, with the objective of avoiding more than one train being offline at any one time. The benefits of such co-ordination are claimed to be more efficient utilisation of skilled contractors and local infrastructure and avoidance of gas flaring. The ACCC proposes to conditionally authorise such maintenance co-ordination, subject to public disclosure of information shared between the projects in the co-ordination process.

For the purposes of this study it is therefore assumed that minimum demand occurs when a single train totally ceases production for maintenance. The Projects' application to the ACCC indicates that at each train minor outages are expected once every 6 months, with major outages every 3 years. Based on Reference 1, LGA understands that minor outages last up to one week and major outages last up to three weeks. Lower demand could occur due to simultaneous unplanned outages but this cannot be quantified at present

Owing to the limited turndown of CSG wells, during an LNG plant outage it is highly desirable for the reduction in demand to be met by redirection of that plant's input gas to other users, such as other LNG plants, gas fired generators and gas storage plants, and for any net reduction in demand to be met by shared turndown of wells across all three projects.

In the Neutral Scenario the potential for the remaining five trains to increase demand to capacity can significantly offset a single plant going offline. Demand from the remaining five trains operating at capacity is only 40TJ/d to 150 TJ/d (1% to 4%) less than the average daily demand in this scenario, an amount that could be absorbed by GPGs or storages. The spread of values is created by differences between the projects. To the extent that the five trains online do not operate at capacity, minimum demand could be lower.

In the Weak Scenario demand from the remaining five trains operating at capacity is actually greater than the average daily demand hence plant outages are unlikely to have any effect on demand.

In the Strong Scenario, where the trains operate much closer to capacity, the demand reductions due to outages are much greater. Demand from the remaining five trains operating at capacity is 482 TJ/d to 617 TJ/d (13% to 16%) less than the average daily demand in this scenario, depending on which train is offline. This is virtually a full train less than average demand. To the extent that the five trains online do not operate at capacity, minimum demand could be lower, though this is unlikely in this scenario.

[37] Details of the Projects' Application are available at www.accc.gov.au

Minimum electricity demand has been estimated assuming that the reduction in gas demand is not compensated by GPGs or storages. In the Neutral Scenario minimum electricity demand is 16 MW to 66 MW (2% to 8%) less than the average daily demand in this scenario. The greater percentage reduction in electricity demand compared to gas is due to the inbuilt modelling assumption that equity gas absorbs the turndown.

In the Strong Scenario minimum electricity demand is 80 MW to 128 MW (9% to 16%) less than the average daily demand in this scenario.

A comparison of peak, average and minimum demand in a representative year (2022) in the Neutral and Strong Scenarios is presented in Table 3-12.

Table 3-12 Comparison of Peak, Average and Minimum Demand in 2022

	Neutral Scenario		Strong Scenario	
	Gas (TJ/d)	**Electricity (MW)**	**Gas (TJ/d)**	**Electricity (MW)**
Peak	4,427	945	4,427	945
Average	3,880	859	4,334	933
Minimum	3,785	816	3,785	816

3.9 Sensitivity of gas and electricity demand to domestic gas and electricity prices

3.9.1 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 gas 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 Strong 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 Weak 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 approximately $US40/bbl at present, taking contract LNG prices with an index of 0.14 from $US14/mmbtu to $US5.60/mmbtu. Asian spot LNG prices have fallen further, from $US20/mmbtu in early 2014 to about $US5/mmbtu at present (Figure 2-6). 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 and initial LNG production levels indicate that take-or-pay will be exceeded.

3.9.2 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 3-13. The lower spot LNG and oil prices currently prevailing may lead to lower domestic gas prices, and the short run substitution of gas for electricity is possible.

Table 3-13 Electricity grid prices at which centralised gas turbine compression power breaks even ($/MWh, $2016)

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

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

In discussions for the 2015 NGFR LNG Projections, 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[38] to $1,700/MWh. Consequently GPPs would be unlikely to voluntarily curtail electricity usage at pool prices below this range.

[38]($5000/TJ)/(8MWh/TJ) = $625/MWh

- 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.

- The gas production operators will also most likely have contracted or hedged their electricity supplies, with the result that they do not directly face NEM spot prices

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.

3.11 Confidence in the Neutral 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 3-14 Confidence in Neutral Scenario projections to 2020

Component	Confidence Level
LNG start up timing	Reasonable
LNG ramp-up period	Reasonable
Plateau LNG production	Reasonable
Gas used in liquefaction	Reasonable
Third party contracts	Reasonable.
Equity gas production	Reasonable.
Gas used in production	Reasonable.

Component	Confidence Level
Electricity used in production	Reasonable.
Gas production by zone	Low
Electricity usage by zone	Low

3.12 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 * quarterly average + (1-A) * previous quarter average; monthly total = average daily rate * number of days in the month
- Last month in quarter; monthly total = quarterly total – 2nd month total – 1st 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 * quarterly peak + (1-A) * previous quarter peak;
- Last month in quarter; peak = 3*quarterly peak – 2nd month peak – 1st month peak;

4. Projections

4.1 Annual projections

Total LNG export projections are presented in Figure 4-1, together with the equivalent projections from the 2015 NGFR LNG Projections (dashed lines). The Neutral Scenario is almost unchanged relative to the 2015 Base Scenario while the Strong Scenario is 2% higher than the 2015 High Scenario owing to revised estimates of LNG plant capacities. The Weak Scenario is similar to the 2015 Low Scenario until 2030 but thereafter it declines owing to non-replacement of CSG production capacity due to low oil/LNG prices. Export levels range from 20 Mtpa in the Low scenario to 31 Mtpa in the High scenario.

It is noted that Weak Scenario LNG production is approximately one train below the six trains' full capacity, i.e. that it could be delivered using only five trains, with one train mothballed. LGA considers it unlikely that one project would unilaterally mothball a train and that mothballing is more likely in the event that two projects merge, possibly for the express purpose of saving costs by mothballing one train.

Figure 4-1 Total LNG export projections

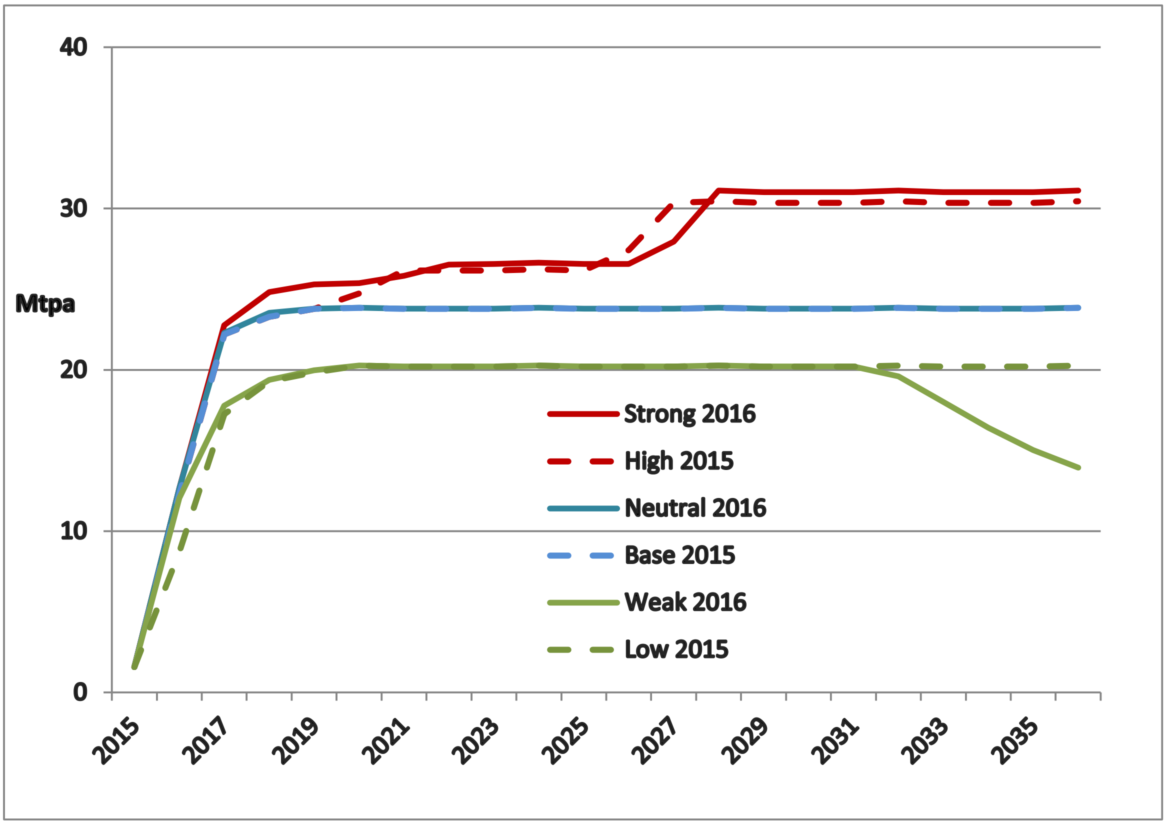


Figure 4-2 and

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 scenario relativities largely track the export relativities, as few changes have been made to the assumptions. However, for electricity usage the 2016 projections are 3% to 10% lower than their 2015 counterparts due to use of a lower estimate of electricity usage per unit of gas production, based on most recent data (refer to section 3.6.3). In energy terms the reductions in electricity usage range from 220 GWh per year in the Weak Scenario to 1,100 GWh per year in the Strong Scenario.

Figure 4-2 Total gas used in liquefaction, transmission and production

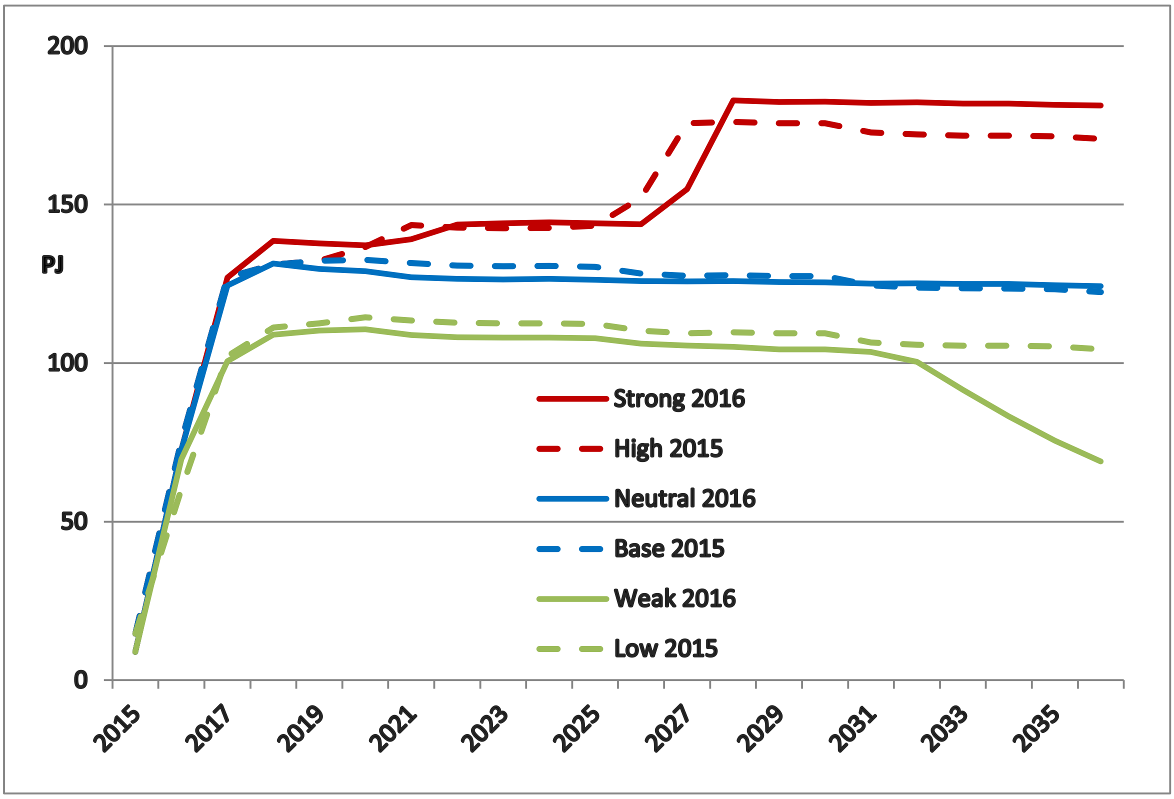


Figure 4-3 Total grid electricity usage in compression

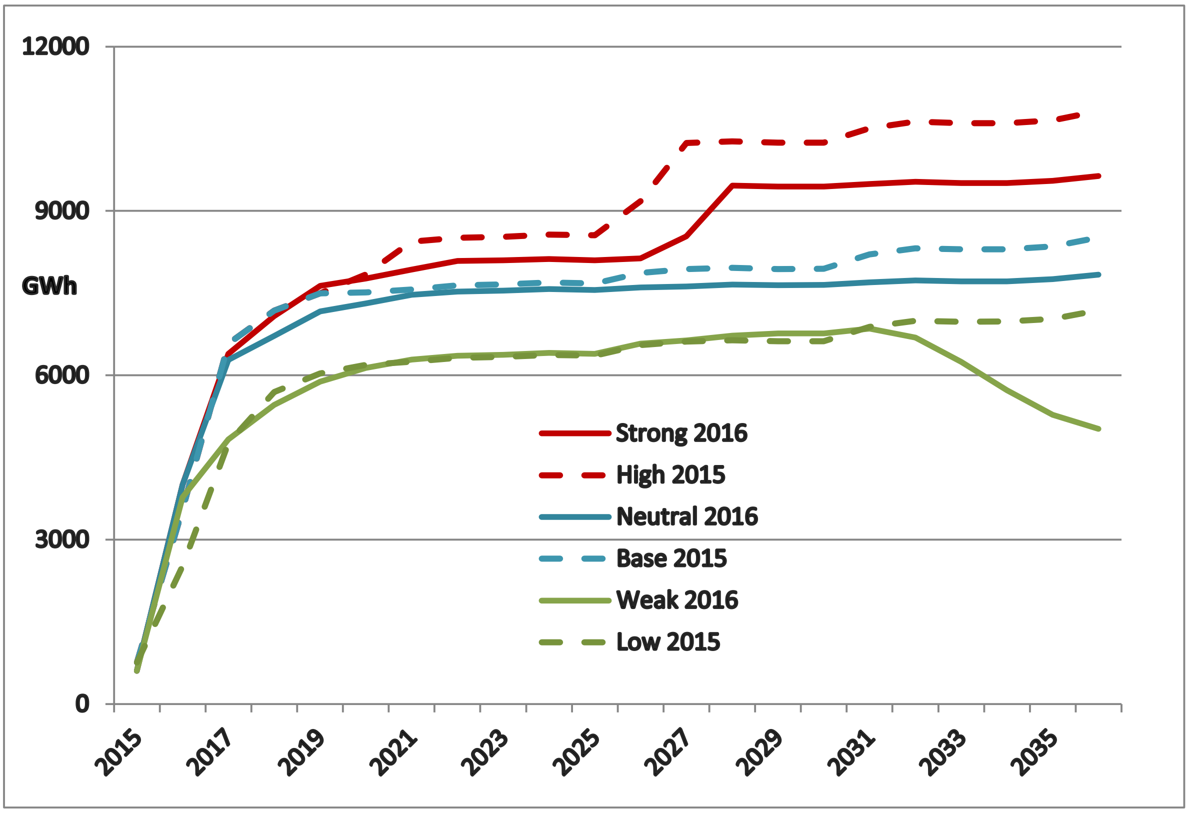


Figure 4-4 to Figure 4-6 show each projects' contribution to the Neutral Scenario projections, for LNG exports, gas usage and grid electricity usage respectively. The upstream components of energy usage figures are based on the upstream gas produced by each project, which is not directly related to its LNG exports owing to production of equity gas for other projects and use of third party gas. 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, Neutral Scenario

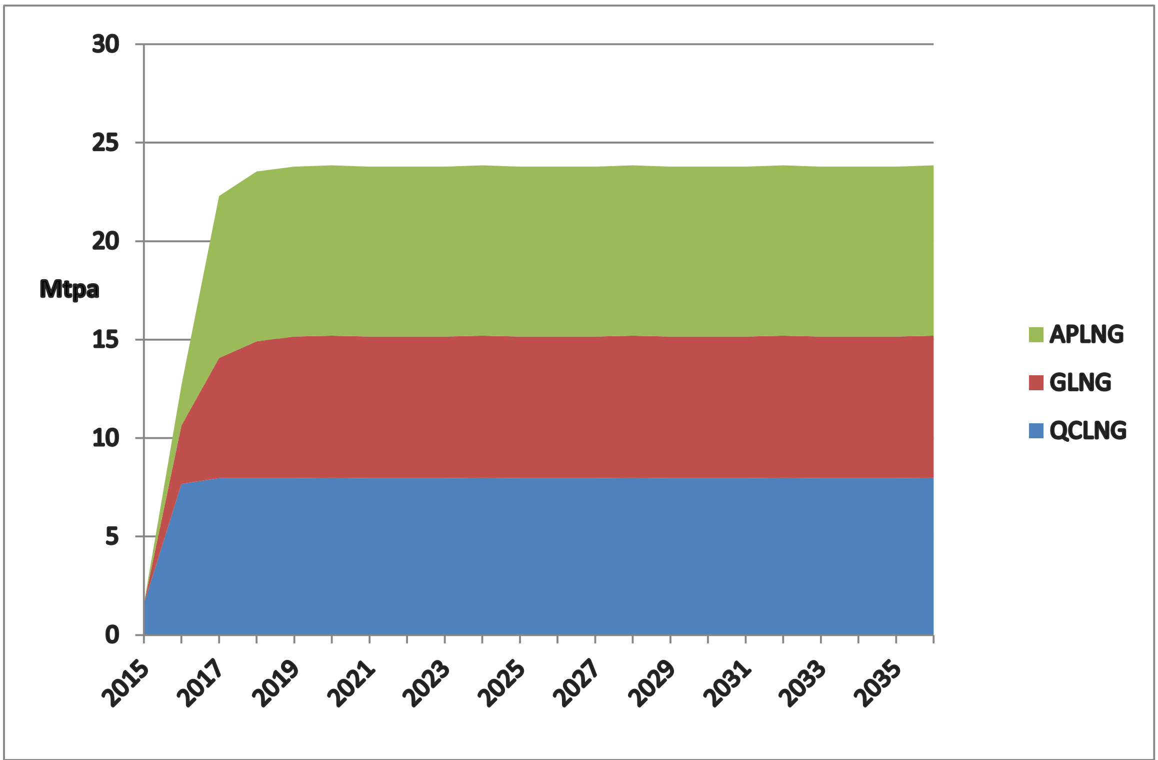


Figure 4-5 Gas used in liquefaction, transmission and production, Neutral Scenario

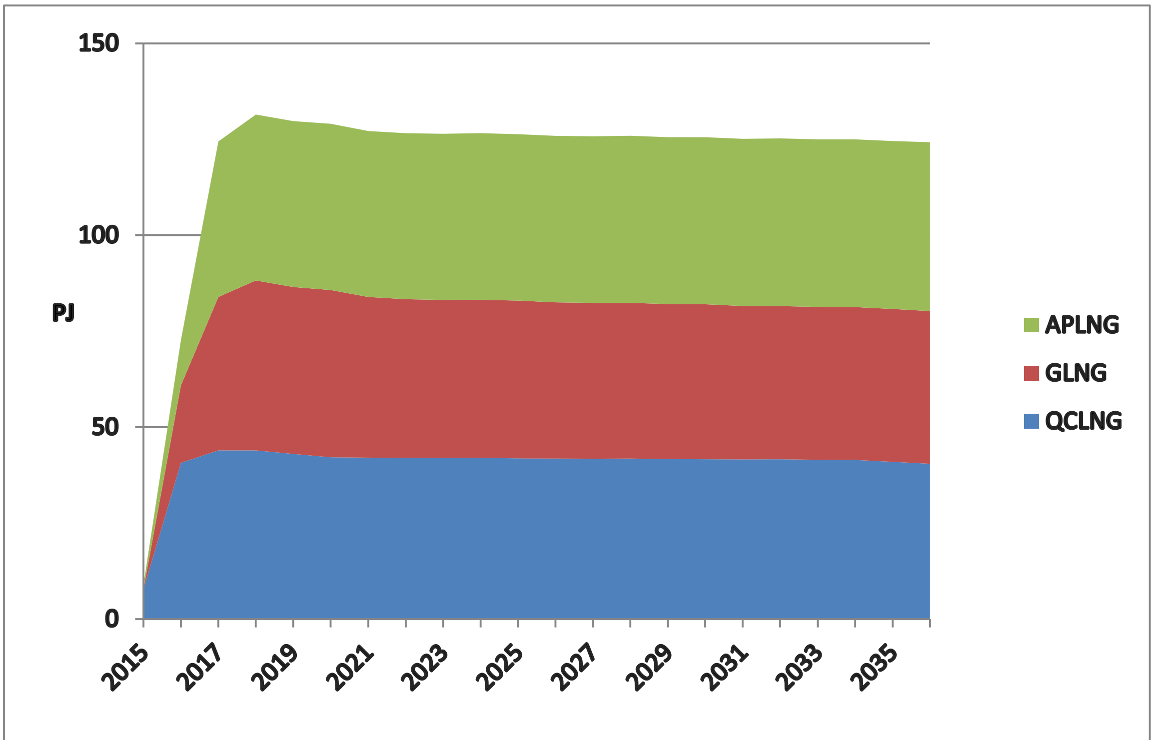
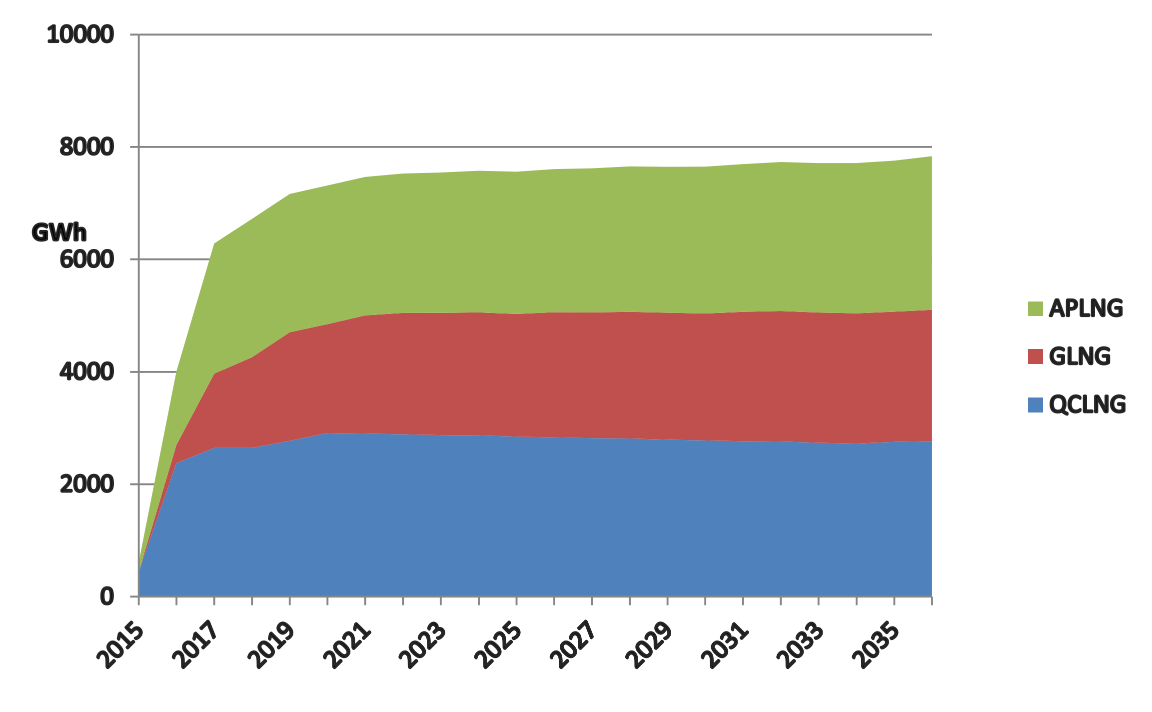


Figure 4-6 Grid electricity usage in compression, Neutral Scenario



4.2 Peak demand projections

Figure 4-7 to Figure 4-9 show the peak winter gas and peak winter and summer grid electricity demand projections respectively. Winter/summer differentiation arises because of the assumed seasonality of gas use in liquefaction.

The 2016 projections of peak demand are based on different models than the 2015 projections. For 2016 the peak gas model assumes that each train can operate up to 110% of its nameplate capacity and will do so from time to time regardless of its annual load, hence the Strong, Neutral and Weak Scenarios are the same from 2020 to 2027, from which point the Strong Scenario includes a 7th train and its peak demand increases. In the Weak Scenario it is assumed that when LNG production starts to decline due to non-replacement of CSG capacity, LNG trains are progressively mothballed, which leads to reductions in peak demand. The change in methodology causes the Strong Scenario peaks to be lower than the 2015 High Scenario peaks, which we now consider to exceed the LNG plants' capacity to take gas.

For 2016 the peak electricity model is based on the peak gas model, hence the scenario patterns are as for peak gas. Neutral Scenario winter MD is projected to be 928 MW in 2020, rising to 1059 MW by 2036 owing to the assumed increase in the proportion of electrically compressed plant over time. Neutral Scenario summer MD is projected to be 915 MW in 2020, rising to 1019 MW by 2035.

Figure 4-7 Peak winter gas demand

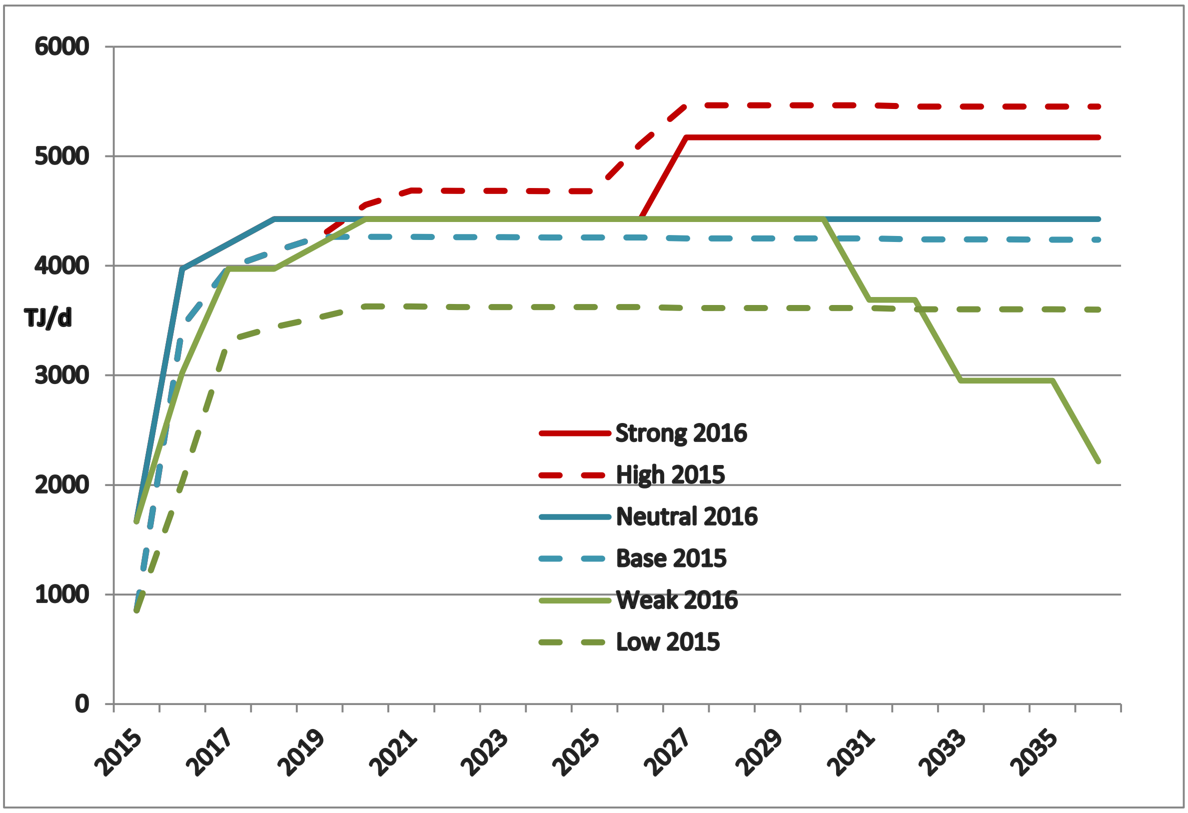


Figure 4-8 Peak winter grid electricity demand

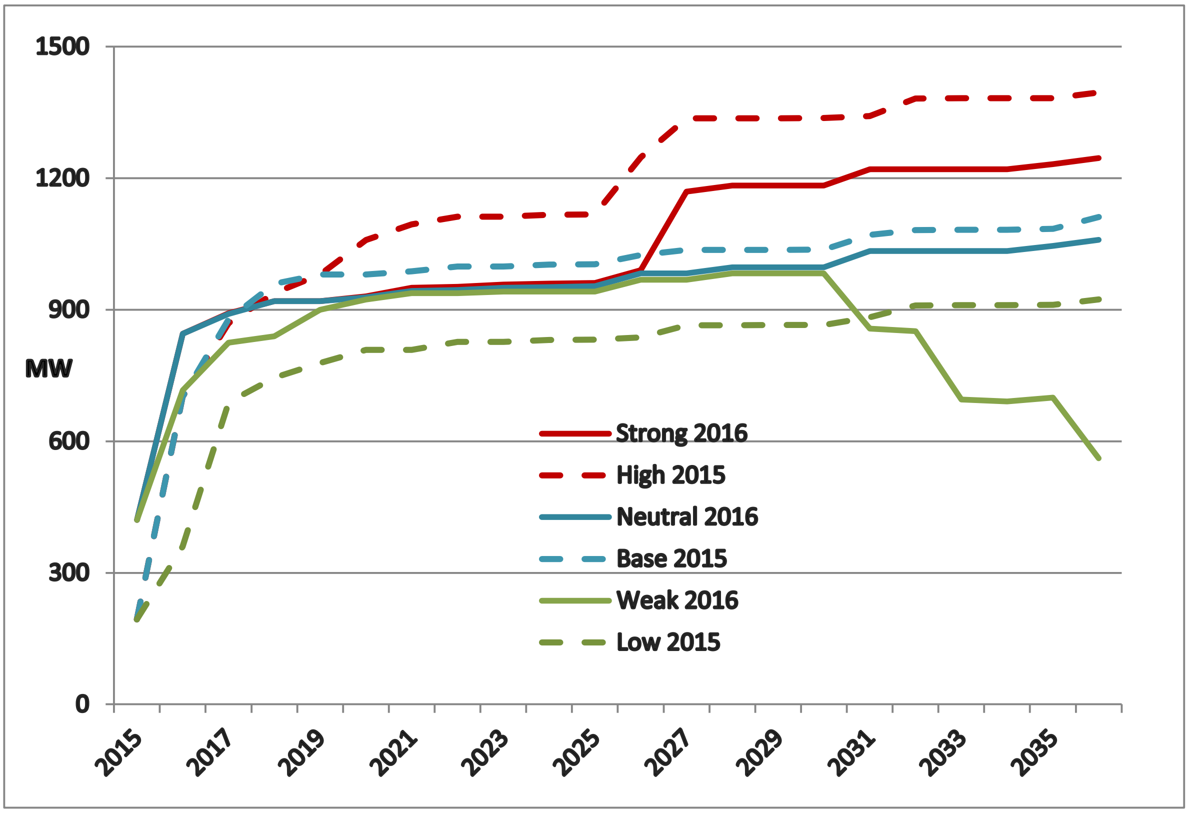
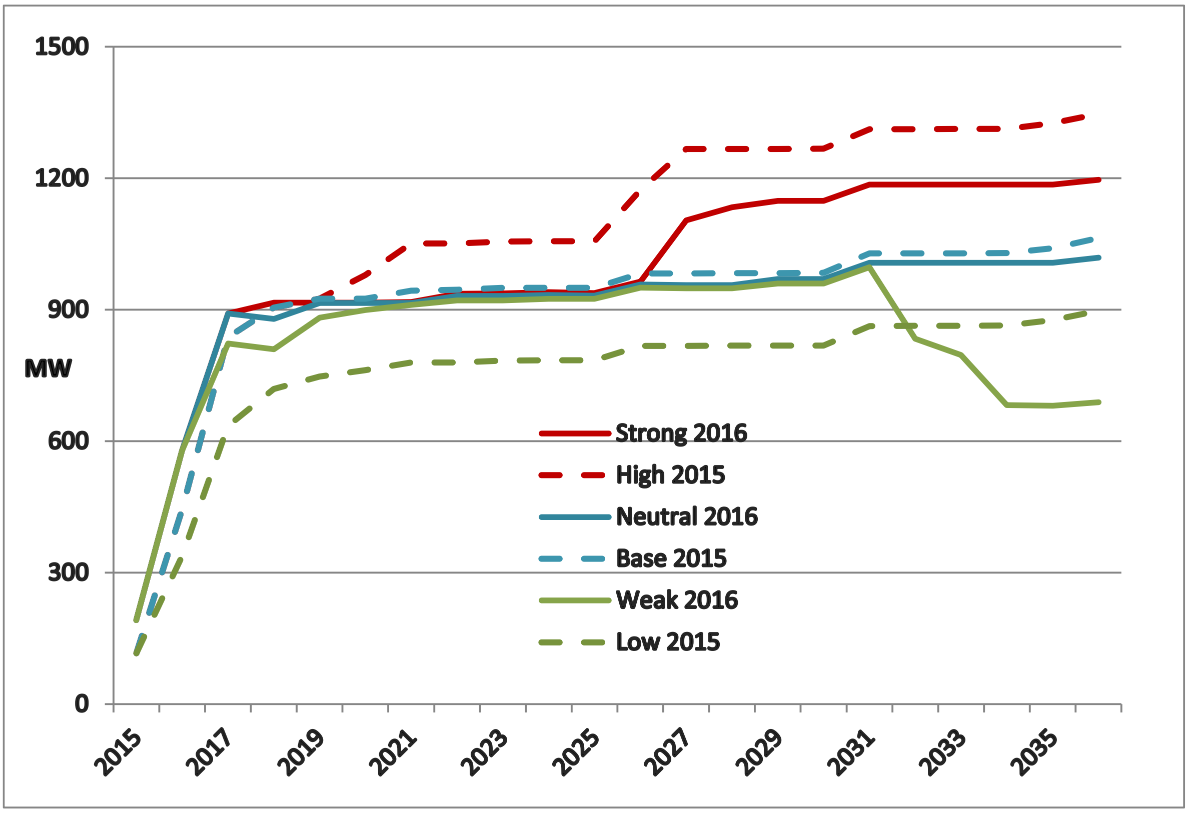


Figure 4-9 Peak summer grid electricity demand



4.3 Monthly projections

Monthly projections of LNG exports, gas usage and grid electricity usage to 2020 are presented in Figure 4-10 to Figure 4-12. Specific points to note include:

- Values up to February 2016 are estimated actuals
- Peaks and troughs in exports are mostly the result of differences in the numbers of days per month
- For gas usage, the monthly charts reflect the seasonality of liquefaction usage used in the projections (most gas is used in liquefaction)
- For electricity the seasonality is barely apparent because electricity use is mostly upstream. The differences between the updated projections and the 2015 NGFR projections are largely due to the revised estimates of the electricity requirements for gas compression.

Figure 4-10 Total LNG export projections

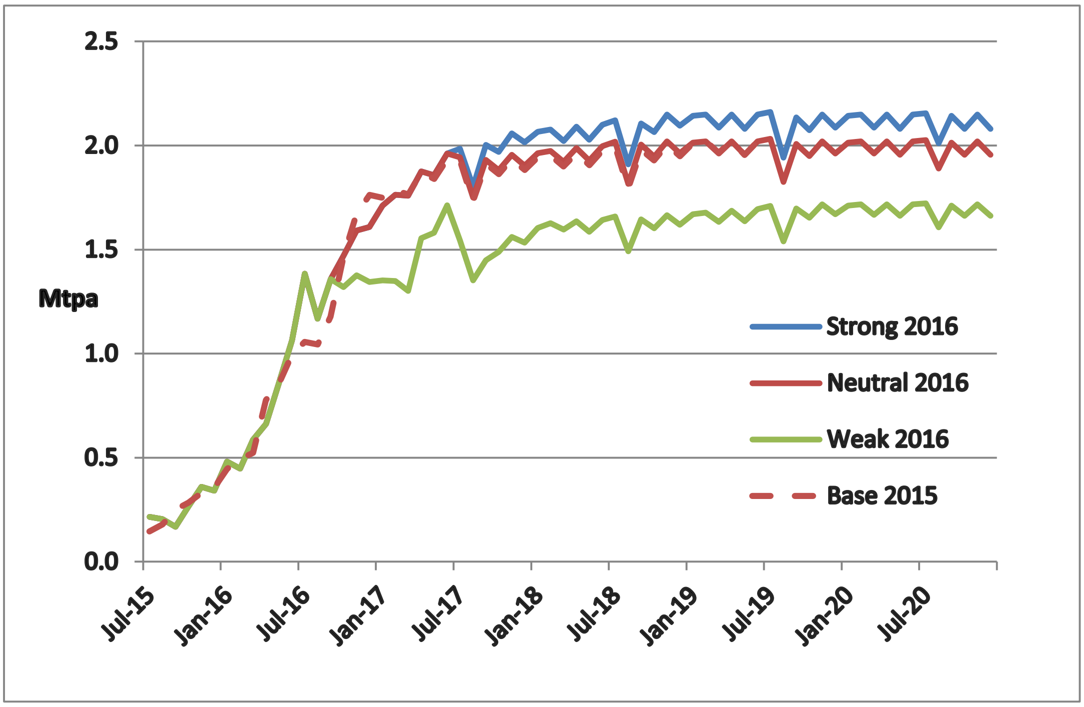


Figure 4-11 Total gas used in liquefaction, transmission and production

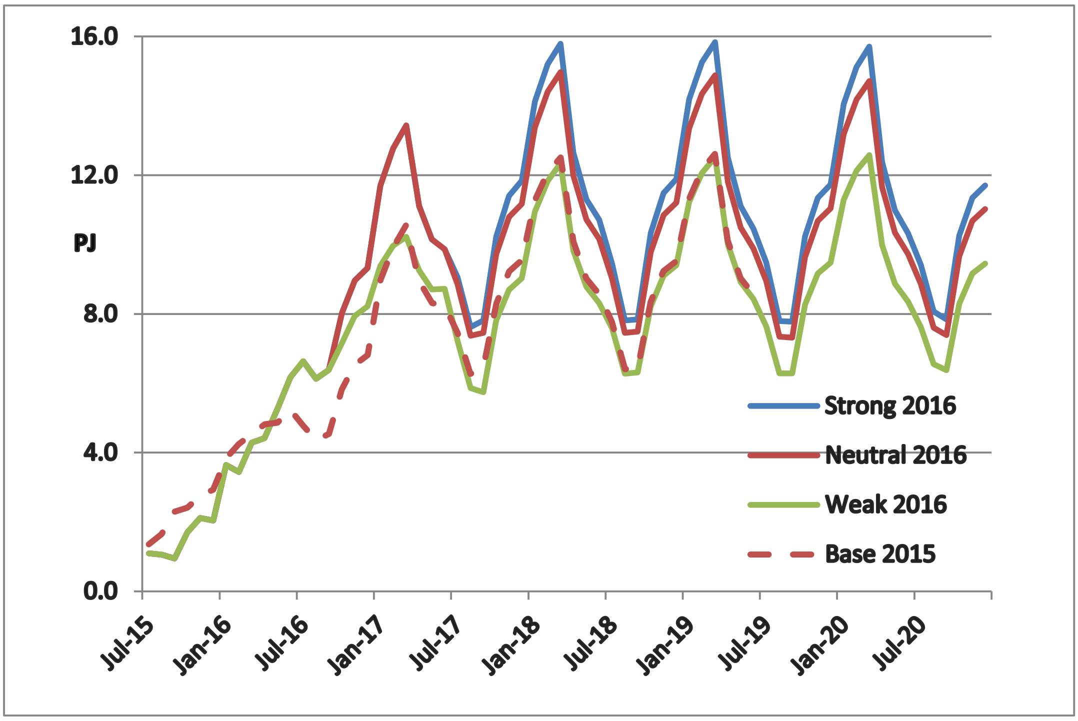
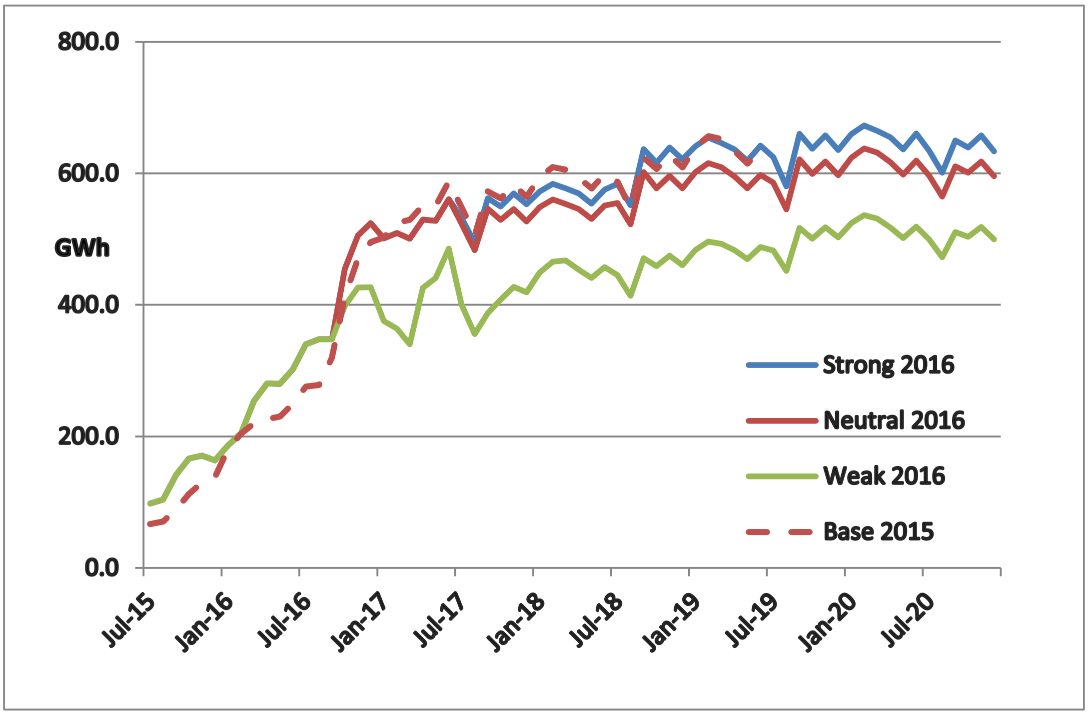


Figure 4-12 Total grid electricity usage



Appendix A. Supporting Analyses

A.1 Factors influencing Short-Term LNG demand

The low Asian LNG spot prices (Figure 2-6), which are indicative of low demand in the short-term, have led share market analysts to question whether the LNG projects will be able to maintain their production targets in the short-run, or even in the longer run. The factors influencing this are addressed in the following sections.

A.1.1 Global LNG Supply and demand

The OIES projections presented in section 2.1.6 indicate that Europe's ability to act as the clearing market for LNG without reducing Russian exports below take-or-pay is a critical factor in growing LNG capacity being absorbed.

The tipping point for short-term LNG markets would come if LNG capacity grows to the extent that Europe no longer absorbs it by holding Russian supply to take-or-pay. It is feasible for Chinese growth to fall further but it is also feasible for the lower prices to attract greater demand in new LNG markets such as Argentina and Pakistan. On the supply side, withdrawal of supply by countries with growing domestic requirements, such as Oman, could bring demand-supply into balance. If the tipping point is reached, LNG output could only be maintained at prices at which it displaces coal fired generation, probably in Europe but also elsewhere. For some LNG suppliers this price could be below their marginal cost of supply and they may withdraw production.

A.1.2 LNG Spot vs Contract Pricing

With the Asian LNG price relativities that have generally prevailed since early 2014, i.e. typical contract prices at or above spot prices as in Figure 2-6, it is to buyers' advantage to minimise contract purchases and maximise spot purchases. Whether this will continue depends on the prevailing oil and LNG prices. With Brent oil currently hovering around $US40/bbl and futures out to 2020 constrained to a band between $US40/bbl and $US55/bbl it appears that LNG contract prices will range from $US5.608mmbtu to about $US7.70/MMBtu (refer to Table A 1) though it could readily escape from this band if there are any surprises.

On balance it therefore seems that LNG contract prices will occupy the upper half of the Asian LNG spot price range and that there is a likelihood that at any time LNG contract prices will be greater than Asian LNG spot prices. Consequently buyers will be incentivised to minimise contract purchases.

Table A 1 LNG Contract price variation

Brent Oil Price ($US/bbl)	$40	$45	$50	$55	$60
LNG Contract $US/MMBtu	$5.60	$6.30	$7.00	$7.70	$8.40

Contractually buyers are effectively obliged to take their take-or-pay level or pay for it anyway. Industry analysts have questioned whether they would do this or break the contract and have generally concluded that they would adhere to the contract, for two reasons: many buyers are participants in the JVs they buy from and reneging on contracts would disrupt the JV, potentially forcing them to sell their share at a time of low value; the contracts are long term arrangements that most parties would not disrupt for short-term gain[39]. For the purposes of this assessment it is therefore assumed that buyers take at (or above) take-or-pay and themselves sell spot if they cannot consume all their gas. The suppliers can also sell their additional capacity in the spot market.

A.1.3 Viability of spot sales

The viability of spot LNG sales by Australian LNG producers in the $US5.60-$US7.70/MMBtu range depends critically on the $US/$A exchange rate and the marginal costs of production in Australia. Table A 2 shows the variation of spot sales netback at the entry to an LNG plant, assuming marginal liquefaction costs are $A2.50/GJ.

Spot sales are viable if the netback exceeds the marginal cost of delivering gas to the LNG plant. In the short run for equity gas (owned by the LNG JV) this is the marginal operating cost of CSG production, thought to be approximately $A2/GJ. In the 2-4 year time frame, as production at existing CSG wells declines, the equity cost becomes the marginal cost of developing and operating new CSG wells and in the 5-10 year time frame the cost of new processing facilities will be incurred. These costs are thought to be approximately $A5/GJ but could be higher if less productive fields have to be developed.

Table A 2 LNG spot sales based on equity gas - netback variation with spot prices and exchange rates ($A/GJ)

	Asian spot price ($US/MMBtu)								
$US/$A exchange rate	$4	$5	$6	$7	$8	$9	$10	$11	$12
1	$1.50	$2.50	$3.50	$4.50	$5.50	$6.50	$7.50	$8.50	$9.50
0.95	$1.71	$2.76	$3.82	$4.87	$5.92	$6.97	$8.03	$9.08	$10.13
0.9	$1.94	$3.06	$4.17	$5.28	$6.39	$7.50	$8.61	$9.72	$10.83
0.85	$2.21	$3.38	$4.56	$5.74	$6.91	$8.09	$9.26	$10.44	$11.62
0.8	$2.50	$3.75	$5.00	$6.25	$7.50	$8.75	$10.00	$11.25	$12.50
0.75	$2.83	$4.17	$5.50	$6.83	$8.17	$9.50	$10.83	$12.17	$13.50
0.7	$3.21	$4.64	$6.07	$7.50	$8.93	$10.36	$11.79	$13.21	$14.64
0.65	$3.65	$5.19	$6.73	$8.27	$9.81	$11.35	$12.88	$14.42	$15.96
0.6	$4.17	$5.83	$7.50	$9.17	$10.83	$12.50	$14.17	$15.83	$17.50
0.55	$4.77	$6.59	$8.41	$10.23	$12.05	$13.86	$15.68	$17.50	$19.32
0.5	$5.50	$7.50	$9.50	$11.50	$13.50	$15.50	$17.50	$19.50	$21.50

Key: Red – spot sales not viable; Yellow – spot sales viable at srmc; Green – spot sales viable generally; Clear – current price and exchange rate ranges

[39] Aussie LNG contracts under pressure. FGE Consultants, July 3 2015.

As illustrated by the colour coding in Table A 2, spot LNG sales using equity gas should be viable under quite a wide range of conditions though in the medium–term, as marginal costs rise, they become more vulnerable to downturns in LNG spot prices. Spot LNG sales based on equity gas appear to be viable at current prices. It is noted that this issue of rising marginal costs differentiates the Queensland LNG projects from conventional gas LNG projects, which can survive lower spot prices.

For third party gas the marginal cost (above take-or-pay under the gas supply contract) is simply the contract price and prices in most third party contracts are understood to be oil indexed. Using the known indices from the Westside-GLNG contract, the marginal profitability of spot LNG sales is as shown in Table A 3. Spot LNG sales based on third party gas appear to be more vulnerable to low LNG spot prices than those based on equity gas. If these sales are not viable, the LNG producers would use third party gas at take-or-pay levels. Spot LNG sales based on third party gas may not be viable at current prices.

Table A 3 LNG spot sales based on third party gas - profit variation with spot prices and oil prices ($US/GJ)

	Asian spot price ($US/MMBtu)								
Oil price $US/bbl	$4	$5	$6	$7	$8	$9	$10	$11	$12
90	-$5.76	-$4.70	-$3.65	-$2.59	-$1.53	-$0.48	$0.58	$1.63	$2.69
80	-$5.04	-$3.98	-$2.93	-$1.87	-$0.82	$0.24	$1.30	$2.35	$3.41
70	-$4.32	-$3.27	-$2.21	-$1.15	-$0.10	$0.96	$2.01	$3.07	$4.13
60	-$3.60	-$2.55	-$1.49	-$0.44	$0.62	$1.68	$2.73	$3.79	$4.84
50	-$2.89	-$1.83	-$0.77	$0.28	$1.34	$2.39	$3.45	$4.51	$5.56
40	-$2.17	-$1.11	-$0.06	$1.00	$2.06	$3.11	$4.17	$5.22	$6.28

Key: Red – spot sales not viable; Green – spot sales viable generally; Clear – current price ranges

A.1.4 Gas availability

A key question is then how much gas is available for spot sales. The assumption in the Neutral Scenario is that gas supply capacity will be established and maintained at a level that enables contracted LNG sales to be met. Is this a viable assumption if LNG sales are instead a mix of contracts at take-or-pay plus spot?

LGA understands that the LNG projects have drilled enough wells to establish the capacity planned for 2016 production, unless well productivity falls below that expected. However the prospect of low profitability may encourage the projects to drill fewer replacement wells and allow capacity to fall, to take-or-pay level say. This would be consistent with reduced capital spending across the upstream sector since mid-2014 but may need agreement from the buyers however, who would have to forego their rights to order cargoes up to their full contract levels. In the case of GLNG, which does not have two full trains of capacity planned for 2016, the expansion planned for 2016-2018 could also be fully or party deferred until LNG prices are more attractive.

A.1.5 Project specific factors

The three projects have different customer exposures. QCLNG is part of a large global LNG trader, Shell, and some sales are to the portfolio rather than customer specific. GLNG has two equal sized contracts with two of its equity shareholders holding 42.5% of the JV, while APLNG has one large contract with a 25% shareholder and a much smaller contract with a non-shareholder.

Credit Suisse[40] has identified that APLNG's major customer, Sinopec, is behind schedule in constructing its receiving terminal and has downgraded its expectations of APLNGs production through to 2018. This is expected to occur through agreed deferral of the start of the contract rather than Sinopec dishonouring the contract.

A.1.6 Longer term factors

Under current projections there will be an excess of LNG supply over demand until 2020. Nevertheless there are a large number of projects in the planning stage waiting for clear signs that the supply bulge will be soaked up before reaching FID. Low gas and oil prices will also hinder reaching FID as no projects are likely to be economically viable at prices below $US10/MMBtu at least and probably $US12/MMBtu. Australian projects are particularly burdened by the cost blowouts experienced in the 2011-2015 investment stampede (in all commodities), though there is every indication that costs are already retreating and will go further.

Timing of the next LNG FID clearly depends on many factors.

A.1.7 Conclusion

The above analysis suggests that under the current low oil and LNG price outlooks there is an increased probability that LNG exports will be below contracted sales levels. There remains a strong case for sales at contract levels but possibly achieved by buyers taking cargoes at take-or-pay levels and LNG projects selling the difference on the spot market. However this depends on investment in gas supply which could be weaker in this environment and capacity may fall below levels currently planned.

A.2 Domestic gas price linkage to oil prices

For the past five years, since the LNG export projects reached FID, gas market commentators have raised the prospect of eastern Australian domestic wholesale gas prices becoming linked to gas export prices and thence to oil prices. In most cases the "linkage" is simply a statement without precise definition, though others have referred to export parity pricing with the netback value of exports as the parity benchmark for domestic prices.

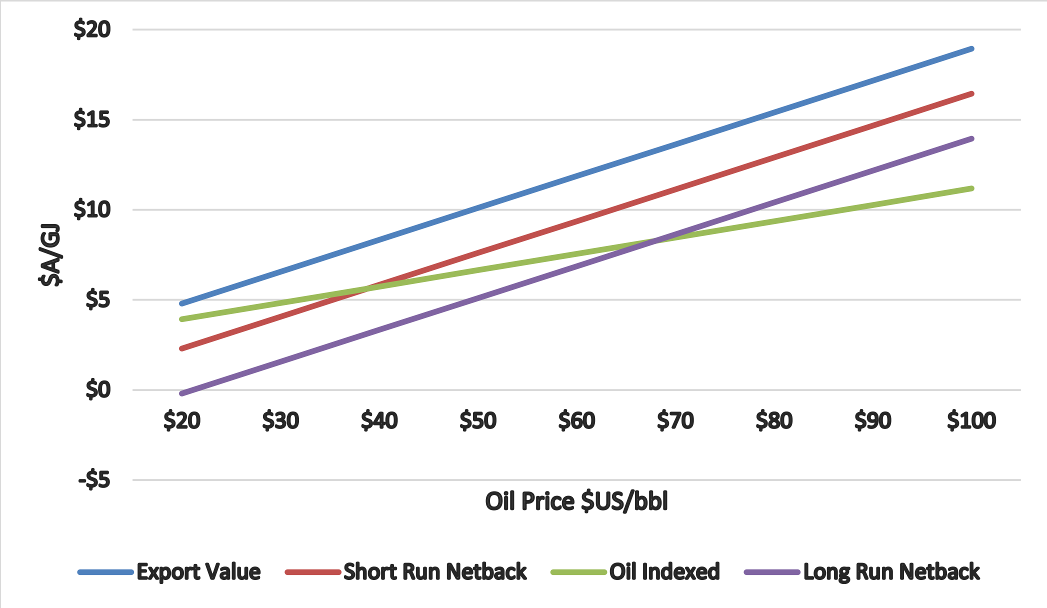
The theory behind this is that gas producers can all access the export market and derive the export value less a fixed cost of delivery (including liquefaction) and therefore domestic purchasers must be prepared to pay this value. In practice the world is more complex, particularly, export capacity is costly and is now relatively fixed, so the exporters are well placed to capture their share of the export value over and above their costs. The reality is therefore that the value of gas to an exporter can vary over a wide range:

- If they have spare export capacity and gas supply is short they may pay up to the short-run netback value (export value less short run liquefaction and delivery costs)
- If they have minimal spare export capacity and gas supply is plentiful, they may pay no more than the cost of production

During the same period a number of new domestic and third party LNG supply contracts have been entered, some reportedly with oil–indexed pricing. The only contract for which the indexation is known with any certainty is the third party LNG contract between Westside and GLNG contract, the oil price sensitivity of which is compared with export and netback values in Figure A 1. Clearly the oil indexed price is not equivalent to either form of netback and gives the exporter, GLNG, a margin ranging from its short run costs at an oil price of $40/bbl to its long run costs at $US65/bbl and higher margins when oil is over $US65/bbl.

[40] Credit Suisse Equity Research 2 July 2015

Figure A 1 Comparison of oil-indexed contract prices with export and netback values



In the Neutral and Weak scenarios where there is no projected increase in LNG export capacity, once all three projects have fully sourced their gas supply the opportunities for further gas suppliers to access the export market are removed and it would be expected that gas pricing would be based purely on domestic market considerations. Price outcomes would not be directly linked to oil prices but may be higher than legacy contract pricing if the only available gas has a higher cost of production.

Export and oil links to domestic prices may be maintained in these scenarios if full the LNG projects never achieve effective full supply sourcing. This may occur if the LNG projects find that continuing development of their CSG resources, to replace declining production at the initial wells, is more expensive than sourcing gas elsewhere, from third parties.

A.3 LNG contract price caps and floors

In LNG contracts that link prices to oil prices there have usually been caps and floors, as well as the slope. The cap is the maximum price accepted by the buyer and the floor is the minimum price accepted by the seller. According to Geoffrey Cann[41] caps are currently set at oil prices in the range $US100/bbl-$US120/bbl with floors at $US40/bbl-$US60/bbl. However Price Waterhouse[42] considers that caps and floors are becoming a thing of the past because buyers and sellers can manage the risks outside of the contract, e.g. by using oil price hedges. Given the lack of transparency of LNG contract terms the actual position is unclear.

In addition to limiting price movements caps and floors can be used to create the opportunity to renegotiate contract price terms (price review). More generally price reviews are triggered on a periodic basis or when one of the parties believes it is suffering financial hardship. Using caps and floors provides a more objective basis for triggering a review.

[41] Oil price weakens, will LNG follow? Fuel Up, 20/10/2014
[42] How are today's LNG market dynamics challenging its historic conventions? PWC 2010

A.4 LNG projects' use of domestic markets

The LNG projects can and have used domestic markets to add flexibility to and manage risk in their equity supply portfolios. The key opportunities are addressed below.

A.4.1 Long-term bilateral contracts

Long-term contracts have been used by QCLNG and GLNG to add supply to their equity gas. Details of contracts are provided in Table 3-6.

Long-term master arrangements are also understood to be in place between the projects to buy/sell or exchange gas via their pipeline interconnections for operational or commercial reasons. The main operational reason would be sale of surplus gas during a planned or unplanned LNG plant outage, which may have a duration of up to a month. Commercial reasons may include short term gas sales to cover a spot LNG cargo to be produced using spare liquefaction capacity. A single cargo is typically 2-3 PJ of gas and the gas would be delivered over a period of up to a week.

A similar agreement is in place between QCLNG and AGL's Silver Springs gas storage facility and may also be in place with other parties with rapid gas use capabilities, such as gas fired generators in Queensland.

A.4.2 Short-term bilateral contracts

The transactions anticipated in the above master agreements may also be managed using shorter term contracts.

A.4.3 Spot markets

The Wallumbilla spot market may be used to buy or sell gas in parallel to the above transactions. Wallumbilla's role is considered likely to remain secondary to the other options owing to: a) the LNG projects will find physical interchange of gas more convenient at the connections between their pipelines, which are downstream of Wallumbilla, than at Wallumbilla; b) the duration of the transactions is typically multiple days, so daily spot transactions are riskier than transactions covering the whole period.

A.5 Tracking the Projections

Sources of information that can be used to track the projections presented in this report are listed below.

Table A 4 Sources of information

Forecast item	Data source	Comments
Electricity usage	NMI consumption data	Available internally to AEMO
Gas usage upstream	CSG production data released by Queensland Department of Natural Resources and Mines	Data is released at 6 monthly intervals 6 months in arrears

Gas usage in liquefaction	N/a.	Must be calculated as the difference between gas delivered to LNG plants and LNG produced & exported
Gas delivered to LNG plants	GBB data on LNG pipeline volumes	
Gas production	GBB data on gas plant production CSG production data released by Queensland Department of Natural Resources and Mines APPEA Gas production statistics	
New gas/LNG contracts	Company media releases	Relevant companies include all eastern Australian gas producers and major traders
LNG Production	Company quarterly reports	Origin report covers APLNG, Santos report covers GLNG, no data for QCLNG.
LNG Exports	Gladstone Ports Corporation	GPC reports on shipping departures. Volume of each cargo can be estimated from vessels' capacities.
Domestic gas market conditions	Market reporting services provided by: Energy Quest; Gas Today	These services draw heavily on the above sources
Global LNG market conditions	Market reporting services provided by: ICIS; Argus; Platts; LNG Industry	These services are designed for market participants

Appendix B. Abbreviations

$A, $US	Australian dollar, US Dollar
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
APA	Australian Pipeline Trust
APLNG	Australia Pacific LNG
BBL	Barrel (of oil)
CNOOC	China National Offshore Oil Corporation
CSG	Coal seam gas (natural gas released from coal seams after drilling)
DOIIS	Department of Industry, Innovation and Science
FID	Final investment decision
FOB	Free on Board
GJ, TJ, PJ	Giga-, Tera-, Petajoule (10^9, 10^{12}, 10^{15} joules)
GLNG	Gladstone LNG
GPG	Gas powered generator
GPP	Gas processing plant
GSOO	Gas Statement of Opportunities
HoA	Heads of Agreement
JCC	Japan Customs Cleared crude price
JV	Joint Venture

kPa	Kilo pascals
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
MWh, GWh	Mega-,Gigawatt-hour (10^6, 10^9 watt-hours)
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NGFR	National Gas Forecast Report
NMI	National Meter Identifier
OIES	Oxford Institute for Energy Studies
ORG	Origin Energy
POE	Probability of Exceedance
PS	Power station
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