Projections of Gas and Electricity Used in LNG
Public Report

Prepared for

Australian Energy Market Operator

Lewis Grey Advisory

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Revision	Date	Description	Approved
1	01/08/17	Draft of Export Scenarios	R Lewis
2	22/09/17	Complete draft report	R Lewis
3	06/12/17	Draft Final Report	R Lewis
4	19/12/17	Final Report	R Lewis
5	19/12/17	Public Report	R Lewis

Contents

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:

Development of a Report and forecasts, detailing forecasts of CSG (in cubic metres) and 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.

- Project plan, including a stakeholder consultation plan - elements of this will likely need to be developed in consultation with AEMO.
- Assessment of stakeholder feedback.
- Stakeholder engagement and consultation.
- Draft Report and forecasts. This is to be a **final** draft document, fully complete with the exception of comments and review by AEMO and industry stakeholders.
- Final Report and forecasts.

The Report must 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 in the Report where the Consultant's forecasts differ from information provided by stakeholders.

The Report, and a data file of the forecasts, must be suitable for publishing on the AEMO website. The forecasts themselves will also be used as a direct input into AEMO's public forecasting and planning reports. More specifically, this Assignment involves:

- Industry (LNG) stakeholder consultation (for Report and mid-year update):
  a. Presentation of findings to industry stakeholders.
  b. Making appropriate revisions to draft Report based on external stakeholder feedback.
- Internal AEMO stakeholder consultation through the Assignment.
  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 CSG (in cubic metres) and LNG production (in million tonnes per annum (Mtpa)) from eastern and south-eastern Australia as well as the gas and electricity consumption associated with this production. Key aspects to be addressed as part of this document are described below.
- Provision of an Excel database(s) providing 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 22nd September 2016 and the report was finalised following discussions with AEMO. This report follows similar reports prepared for AEMO by LGA in April and November 2016, referred to as the 2016 NEFR LNG Projections Report and the 2016 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 after start-up. Both these trains transitioned to operational/commercial status in March 2016. GLNG’s second train started LNG production in May 2016 and APLNG’s in October 2016. Cumulative cargoes shipped by each project up to June 30 2017 were: QCLNG, 241 (est.); GLNG, 124; and APLNG, 132.

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. Further capacity expansion now seems unlikely in the near term but a potential future option is for a third train at one of the existing projects using the gas resources of the cancelled Arrow project.

The purpose of this study is to provide AEMO with consistent estimates of the gas supply required for export, including gas used in the supply chain, and grid-supplied electricity used in the supply chain. The relevant estimates are used in the preparation of AEMO’s 2017/18 energy projections It is noted that the gas and electricity usage projections do not include usage associated with gas produced to meet domestic demand.

The key elements of this report are:

1. Three scenarios concerning the overall levels of LNG 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 2016 NGFR LNG Projections were finalised, all trains have reached commercial operation status and the number of announcements regarding production targets has reduced significantly, with just one major media release by Santos noting that GLNG will ramp production to 6 Mtpa (77% of nameplate capacity) by 2019.

LGA has therefore taken a new approach to deriving export scenarios in 2017, using a global LNG market model to examine the economic prospects of the projects in the context of the global LNG market. This gives greater insights than the previous approach which used third party projections for this purpose.

LGAs' methodology for estimating electricity and gas used in the LNG supply chain remains essentially the same as in 2016 but with an increased number of parameter estimates based on actual gas and electricity usage. A declining number of 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.

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 –– slow ramp in line with current weak LNG market conditions, reaching capacity (25 Mtpa) by 2023 as conditions improve.
- Weak Scenario – slow decline in production until 2023 and then a more rapid decline to 9 Mtpa by 2030. The latter is due to market conditions remaining too weak to support investment in further wells to offset declining CSG production.
- Strong Scenario – faster ramp to capacity by 2021, with stronger LNG market conditions supporting higher capacity utilisation and a 7th train added by 2027. Total production ultimately reaches 33 Mtpa.

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

Gas and Electricity Usage Methodology

The methodology used in this study is the same as the methodology applied in the 2016 NGFR LNG Projections Report, with all parameters updated using data up to June 30 2017.

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 9% of gas input to the plant, based on actual usage, an increase relative to the 2016 estimate which was based on planning data.
- 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 on this pipeline.
- 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 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

[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

AEMO. The electricity usage figures represent a decrease compared to 2016 NGFR LNG Projections Report estimates.

Export and Energy Usage Projections

Total LNG export projections are presented in Figure E 1, together with the equivalent projections from the 2016 NGFR LNG Projections (dashed lines). In all scenarios, there is a slower ramp up to the plateau level compared with the 2016 Projections, with most of this attributable to the alignment of the 2017 scenarios with current weak global LNG market conditions. The Strong scenario has the same plateau levels as in 2016 but the Neutral Scenario is 6% higher, reflecting production reaching equilibrium at nameplate capacity instead of contract levels.

The decline in the Weak Scenario starts earlier than in the 2016 projections – the decline is due to non-replacement of CSG production capacity due to low LNG prices.

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

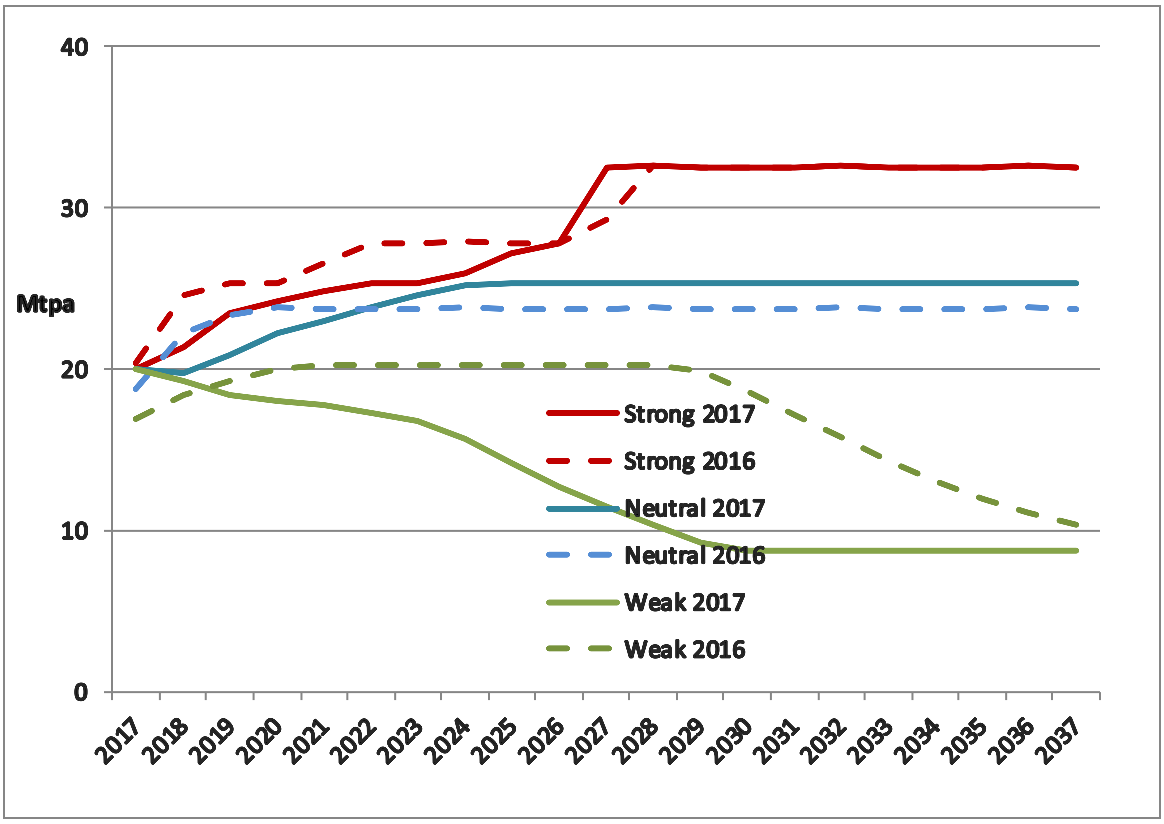


Figure E 2 and Figure E 3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production.

For gas usage, the significant increase in estimated gas used in 2017 compared to 2016 is due to the switch from theoretical unit usage rates for liquefaction to rates derived from actual production data (refer to section 3.4). The scenario relativities largely track the export scenario relativities.

For electricity usage, the reduction in usage in 2017 compared to 2016 is mostly due to the lower usage of electricity in a small number of plants, which was not detected in 2016.

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

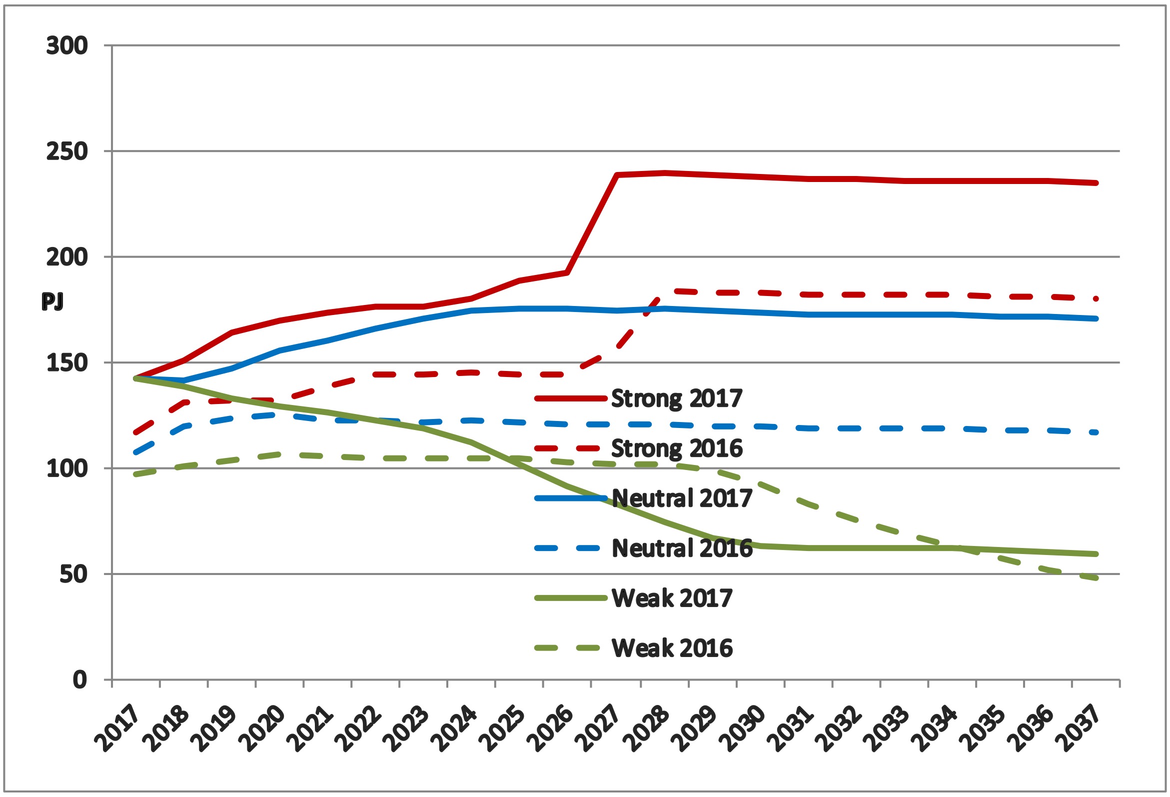
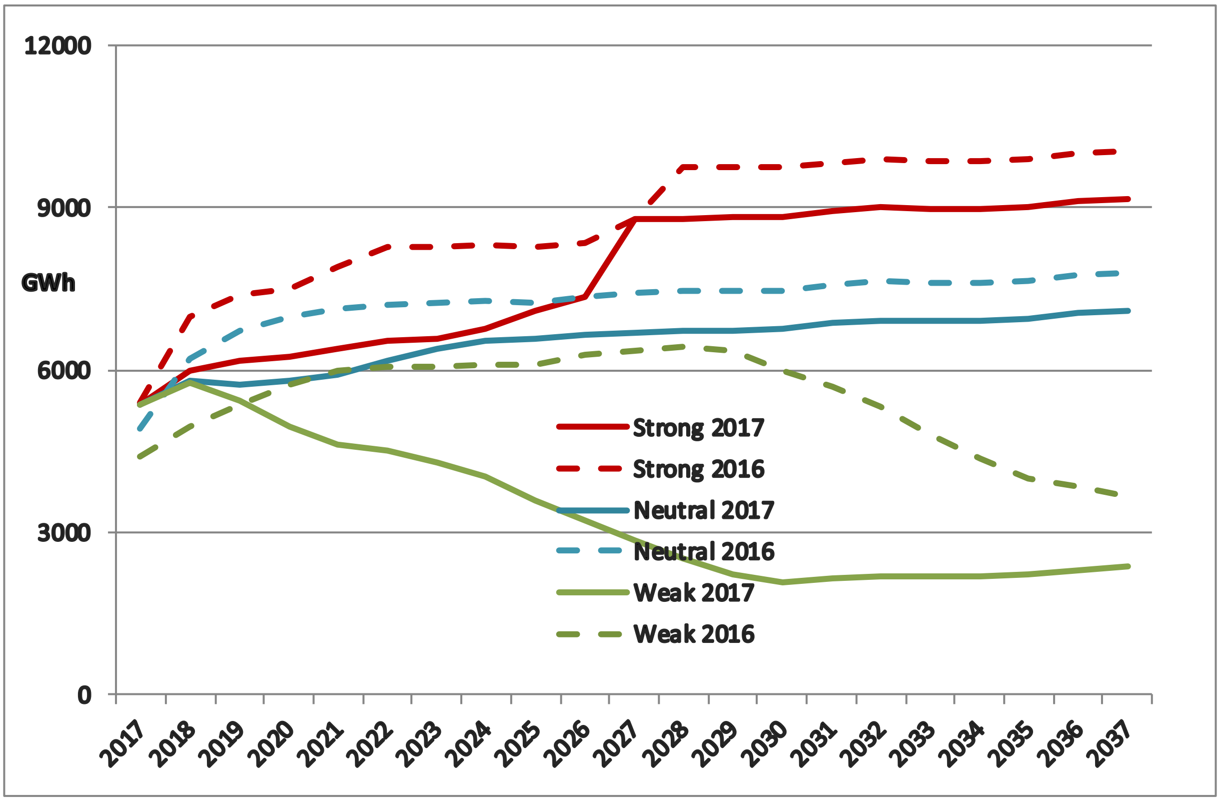


Figure E 3 Total annual grid electricity usage (Financial Year)



Summary of changes to the projections

Changes to the projections in this report compared to the 2016 NGFR LNG Projections are summarised below. The changes reflect changes announced by the project operators, analysis of the projects' role in the global LNG market and analysis of recent actual gas and electricity usage by the projects.

- Global LNG market – weak demand and prices continue to be the main feature. The impact of these on the Gladstone LNG start-ups has been assessed using a global LNG market model.
- LNG exports – with all trains now in production the major change is slower ramp-up in line with weak market conditions until the early to mid-2020s. Projected volumes: are higher in the Neutral Scenario; the same in the Strong Scenario; and decline earlier in the Weak Scenario.
- Gas used in liquefaction – no changes in methodology, parameter estimates revised upwards.
- Gas used in transmission compression (Strong Scenario only) - no changes in methodology or parameters.
- Gas used in processing – no change in estimated gas usage per unit of gas production due to difficulty interpreting data updates.
- Grid-supplied electricity used in processing – a decline in estimated electricity usage per unit of gas production, due to data updates.
- Peak gas and electricity demand – similar methodology with minor variations in outcomes.

1. Introduction

1.1 LNG exports from Gladstone

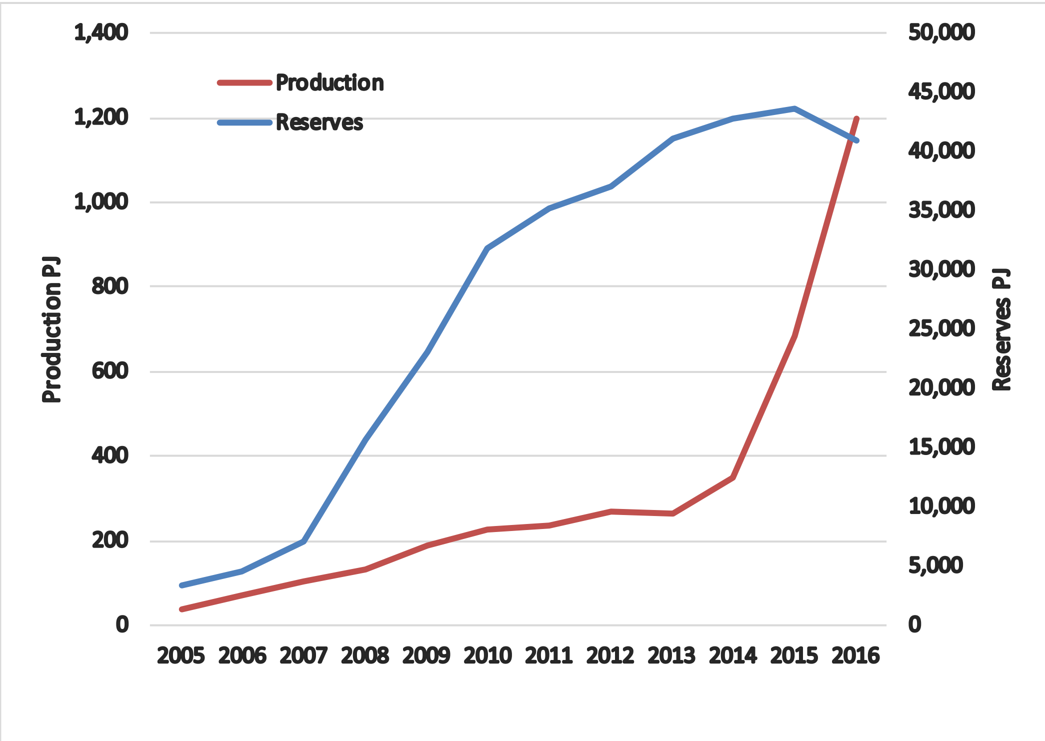
LNG exports from Gladstone were first conceptualised in 2007 and after successful planning and marketing phases, three projects commenced construction in 2011/12: Queensland Curtis LNG (QCLNG); Gladstone LNG (GLNG); and Australia Pacific LNG (APLNG). First exports started in early 2015 and all six planned trains have been operational since October 2016. LNG production reached 20 Mt in 2016/17 and is expected to reach full capacity of 25.3 MT during the early to mid-2020s.

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 from 2003 to 2008 and from 2012 to 2014. Since this time however both contract and spot LNG prices have been low.

Figure 1-1 illustrates the development of Queensland CSG reserves and production from 2005 to 2016. Since 2007 the reserves have been developed to support the production growth that started in 2014 and has taken production to over 1,200 PJ in 2016.

Figure 1-1 Queensland CSG Reserves and Production (Years Ending 31 December)



Source: Queensland Department of Natural Resources and Mines

1.2 The export projects

The three Queensland LNG export projects have the following features:

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

2) 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 became commercial and its operation passed from the constructor to the owner/operator. During the start-up phase the projects sold commissioning cargoes on a lower delivery commitment basis.

Table 1-1 Queensland LNG Project Parameters

Project	Partners	Nameplate Capacity (Mtpa)	Sales Contracts	
			Party	Volume (Mtpa)
QCLNG[2]	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[3]	Santos (30%)	7.8	*Petronas*	*3.6*
	Petronas (27.5%)		*Kogas*	*3.6*
	Total SA (27.5%)		Total	7.2
	Kogas (15%)			
APLNG[4]	Origin Energy (37.5%)	9.0	*Sinopec*	7.6
	Conoco Phillips (37.5%)		*Kansai Electric*	1.0
	Sinopec (25%)		Total	8.6

[2] bgdatabook 2014
[3] STO 2014 Investor Seminar, 26 November 2014
[4] Origin Energy International Roadshow , September-October 2014

3) 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.

4) 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.

5) 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) in December 2014 and the other two projects have contemplated but not completed sales of their pipelines. In June 2016 APLNG reported that a pipeline sale was “not being actively pursued at the moment”[5].

6) The HoA between Origin Energy and ENN Energy of China for 0.5 Mtpa of LNG based on Origin’s 260 PJ Ironbark CSG field, announced on 1st March 2016[6], was converted into a Sales and Purchase agreement for 0.28 Mtpa on 21 December 2016. Deliveries are to start in calendar 2018 or 2019 and run for 5 years. The SPA provides Origin with flexibility to supply from its portfolio.

Table 1-2 Queensland LNG Project Performance

Project	**Commenced Exports**		**Exports (MT)**		
	Train 1	Train 2	**2015/16**	**2016/17**	**June Q 2017 Annualised**
QCLNG	January 2015	July 2015	7.7	7.6	6.7
GLNG	September 2015	May 2016	2.4	5.2	4.4
APLNG	September 2015	October 2016	1.8	7.2	9.0
Total			12.0	20.0	20.1

It is noted that while APLNG had exceeded its contracted supply level by the June quarter of 2017, QCLNG and GLNG were at 81% and 59% of their contracted levels respectively and aggregate exports were at 82% of the total contracted.

Further capacity expansion now seems unlikely in the near term but a potential future option is for a third train at one of the existing projects using the gas resources of the cancelled Arrow project. Arrow’s 50% owner, Shell, became the majority owner of QCLNG on 16th February 2016, when it completed its take-over of BG Group[7].

The purpose of this study is to provide AEMO with consistent estimates[8] 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 2017/18energy projections, in a similar manner as LGA’s previous projections were used in the 2016 NEFR and NGFR.

[5] Sydney Morning Herald, 6 June 2016
[6] Origin Energy Website
[7] 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.
[8] In particular, changes in export outlook can be consistently incorporated into both gas and electricity forecasts

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 future trains constructed, if any; and levels of exports for each operating train.

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 shortly prior to the completion of the draft report, on 22nd September 2017. Since that date the following material information has become known:

- The ADGSM process described in section 2.1.1 below has resulted in the LNG projects providing AEMO with projections of their exports (including gas usage) for 2017, 2018 and 2019, for each AEMO scenario. AEMO has provided LGA with the aggregate projections for each year and scenario. The LNG projects' projections for 2017, 2018 and 2019 are largely consistent with the logic of LGA's independent draft projections, which were provided to AEMO on September 22nd, 2017, and form the basis of LGA's final projections for these years presented in this report.
- On December 1st, 2017, it was announced that Arrow Energy had entered into a 27-year contract to supply Shell's QCLNG plant with 240 PJ p.a., starting in 2021, from its Surat Basin CSG resources[9]. Arrow will share QCLNG operated infrastructure, such as gas compression, processing and transmission, so it appears that the Arrow gas will in part, if not in full, substitute for QCLNG gas rather than be additive, though the contract is sufficient to support a 7th train at QCLNG. Further, Shell (QCLNG's majority owner) has announced that it will sell gas both domestically and internationally through QCLNG.

  Until further information becomes available LGA has therefore assumed that this contract will not affect gas exports in each scenario, though it may increase the likelihood of the Strong Scenario, which involves construction of a 7th train.

[9] Arrow Energy Media Release, 1st December 2017.

2. LNG Export Scenarios

2.1 Determining factors

For the 2016 NGFR LNG Projections LGA constructed three scenarios for LNG exports from eastern Australia based on near-term, mid-term and long-term considerations. These considerations were:

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

Since the publication of the 2016 NGFR LNG Projections there have been limited changes to the first three of these considerations:

- AEMO planning and forecasting scenarios in relation to LNG are the same
- For the current eastern Australian LNG projects, the liquefaction construction phase is complete but the production growth phase continues, albeit more slowly than previously anticipated. No new export projects are in prospect.
- The global LNG market continues to be characterised by oversupply, with most commentators believing that supply and demand will not come into balance until the 2020s.

2.1.1 The ADGSM

Perceptions regarding gas resource availability have changed significantly during 2017 however. In March of this year AEMO released an update of the Gas Statement of Opportunities (GSOO), which identified potential shortfalls of gas supply to the eastern Australian domestic market. The Australian Government responded to this threat by introducing the Australian Domestic Gas Security Mechanism (ADGSM), a framework for restrictions on the export of LNG to be imposed where the Resources Minister (the Minister) determines there is a reasonable prospect of a supply shortage in the domestic market.

The purpose of the ADGSM is to ensure that there is a secure supply of gas to meet the needs of Australian consumers, including households and industry, by requiring, if necessary, LNG exporters which are drawing gas in net terms from the domestic market to limit exports or find offsetting sources of new gas.

AEMO is to advise the Minister in relation to the prospects of a domestic supply shortage, based on projections of domestic and LNG demand balanced against available supply. During 2017 AEMO engaged with the LNG projects, which provided estimates of their likely exports and production in 2018 and 2019. In September 2017 AEMO issued a 2017 GSOO Update, indicating a range of domestic gas shortfalls in 2018 and 2019, which in subsequent discussions with the Australian Government the LNG Projects have committed to supply.

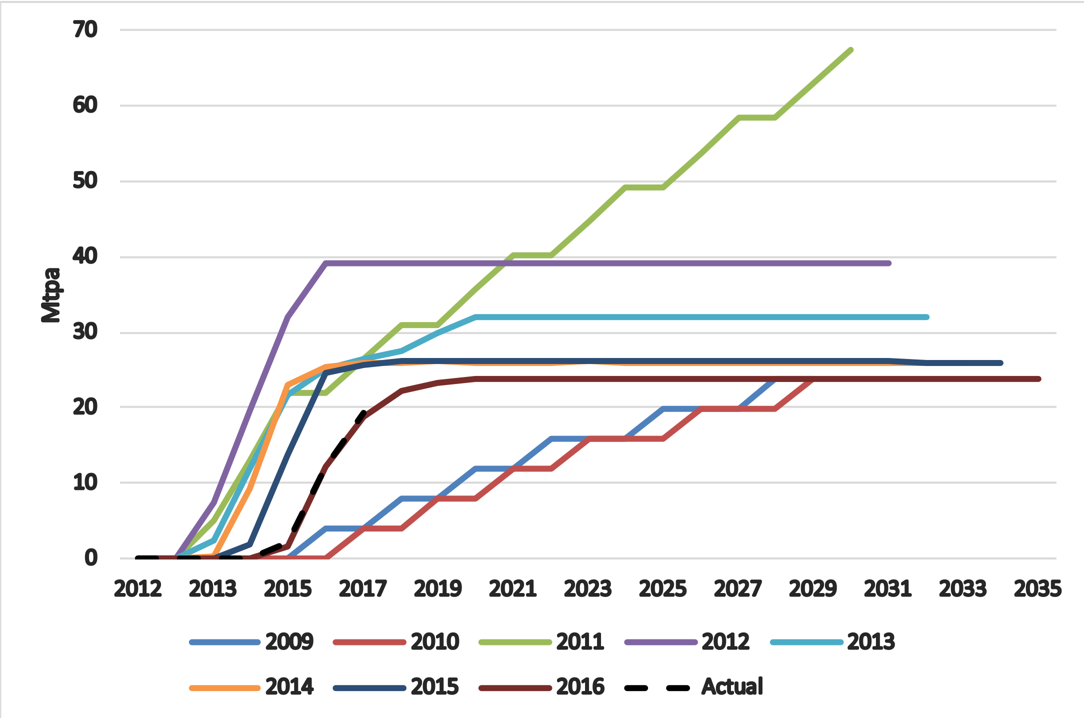
LGA's export projections are aligned with the LNG Projects' projections in 2018 and 2019.

2.1.2 Previous Projections

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, 2015 and 2016, are illustrated in Figure 2-1. The projections reflect the information available when they were prepared, for example, before any LNG projects reached FID in 2011 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



2.1.3 AEMO planning and forecasting scenarios

AEMO developed three scenarios for use in planning studies in 2016[10] and these have been retained for 2017. The scenarios are 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 2017 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

[10] 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

2.1.4 Additional LNG Trains in Queensland

2.1.4.1 Other Planned projects

A fourth two train LNG project planned for Curtis Island, proposed by Arrow Energy, was cancelled in January 2015[11]. Arrow is now 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. Please refer to section 1.3 for a recent update on the use of these reserves.

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 2023. Projects that may proceed after 2023 are unlikely to be at the planning stage yet.

2.1.4.2 Further trains for the existing projects

APLNG[12] has environmental approval for 4 trains and QCLNG[13] and GLNG[14] each have approval for 3 trains, however none of the projects currently has sufficient reserves to support a third train (refer to section 3.7 for details on each project's gas reserves). Further trains at the existing projects would have cost advantages over new projects as they could share infrastructure with existing trains – such brownfield capacity expansions may cost 30% less than entirely new capacity.

2.1.4.3 Assumptions in Previous Forecasts

In the 2016 NGFR LNG Projections LGA concluded that one among the 48 additional LNG trains required globally by 2030 in the Strong Scenario would be a 7th train in Queensland, which would reach FID by 2022 and be in production by 2026 or 2027, at the midpoint of the projection timeframe.

For the Neutral and Weak Scenarios, it was assumed that there were no additional trains.

2.1.5 Global LNG demand

LNG currently supplies approximately 9% of world demand for gas, with 20% supplied by international pipelines and the majority, 71%, supplied by domestic production and pipelines[15]. 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 lastly LNG, because of the high cost of liquefaction, typically being the most expensive.

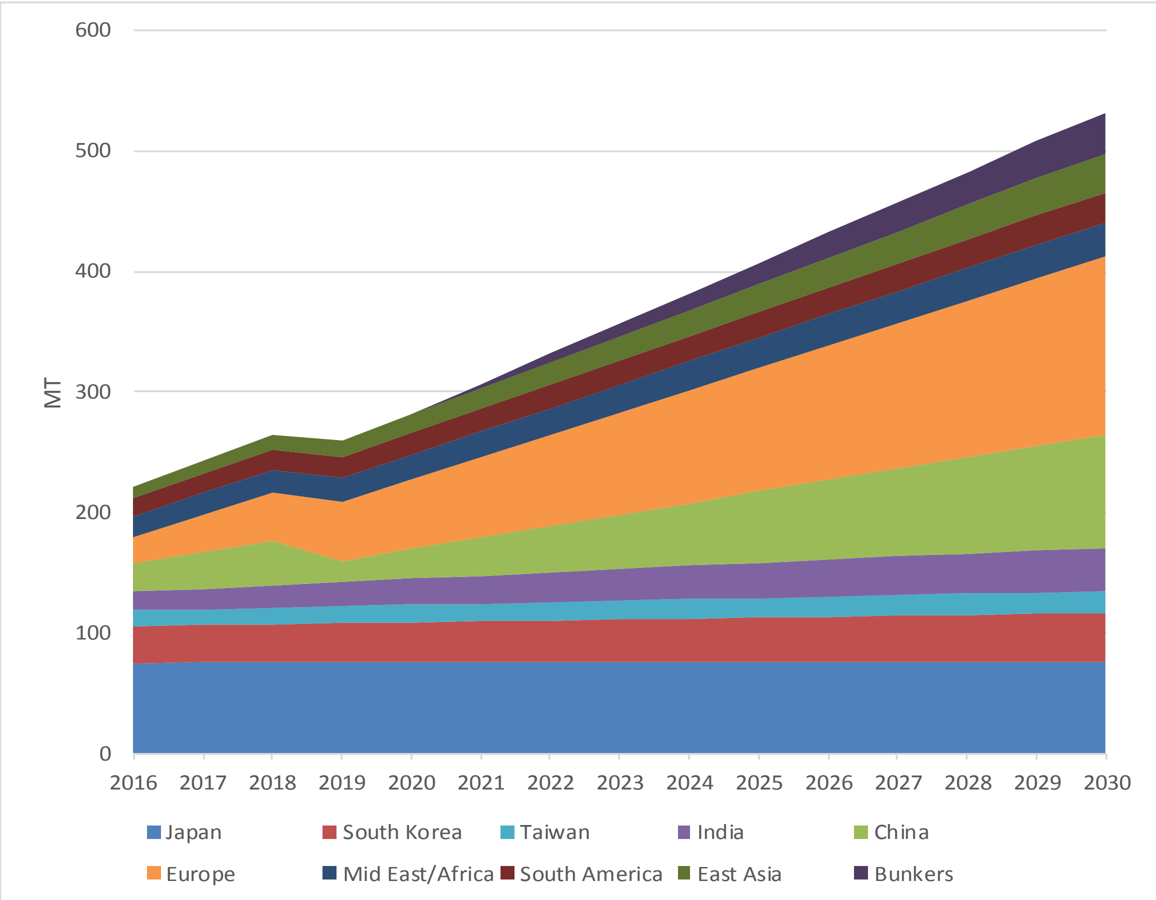
[11] "Shell shelves Arrow LNG project in Queensland. Brisbane Times January 30, 2015.
[12] Queensland Co-ordinator General Website
[13] Ibid
[14] GLNG Project Environmental Impact statement - Executive Summary.
[15] Gas Market Report 2014, Bureau of Resources and Energy Economics, November 2014.

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 "traditional importers", Japan, Korea and Chinese Taipei, which currently account for 54% 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 "new importers" 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.

Global LNG projections derived from those prepared by the Oxford Institute for Energy Studies are illustrated in Figure 2-2. These anticipate that traditional importers demand will be flat and growth will mainly be in Europe (due to declining domestic production and assuming flat pipeline imports, mainly from Russia) and China (where it is assumed that domestic production growth does not keep up with gas demand). The aggregate growth rate to 2030 is 6% p.a., slightly above the 4% to 5% range estimated by Shell[16]. It is noted that the fall in demand in 2019 is due to the assumed start of Russian pipeline gas supply to China.

Figure 2-2 Global LNG Demand Projections



Source: The Impact of Lower Gas and Oil Prices on Global Gas and Oil Prices. Oxford Institute for Energy Studies, July 2015.

[16] Shell LNG Outlook2017.

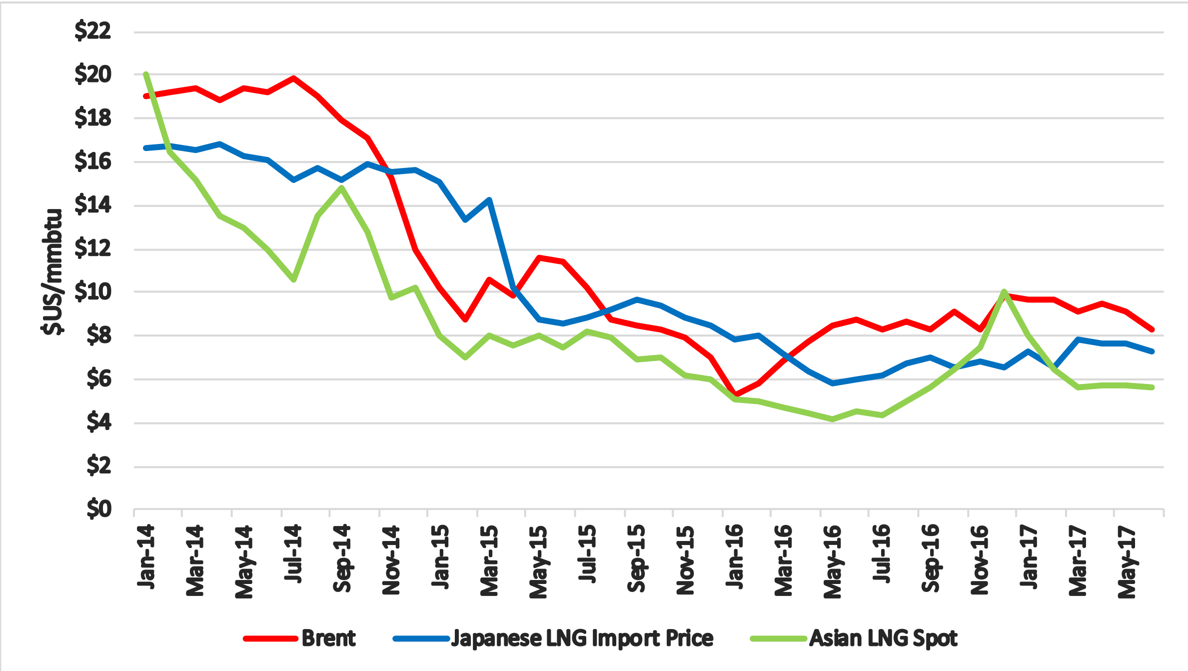
2.1.6 Global LNG Supply

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

LNG demand and supply capacity tend to move in step with one another. This is largely because the majority of LNG is supplied under long-term contracts between the buyer and seller which impose take-or-pay conditions on the buyers. The revenue from contracts underwrites the large capital investments by the sellers – without it debt funding would not be available. When buyers foresee demand growth they negotiate new contracts for new capacity and it is reasonable to assume that after that capacity has been constructed the demand for it will be there, 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. Between 2012 and 2014 for example, no new supply capacity entered the market and some established capacity was withdrawn[17]. 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 (QCLNG, GLNG and APLNG) entered the market and Chinese demand growth slowed dramatically, resulting in weak spot markets with low prices.

Figure 2-3 Falling oil and LNG prices

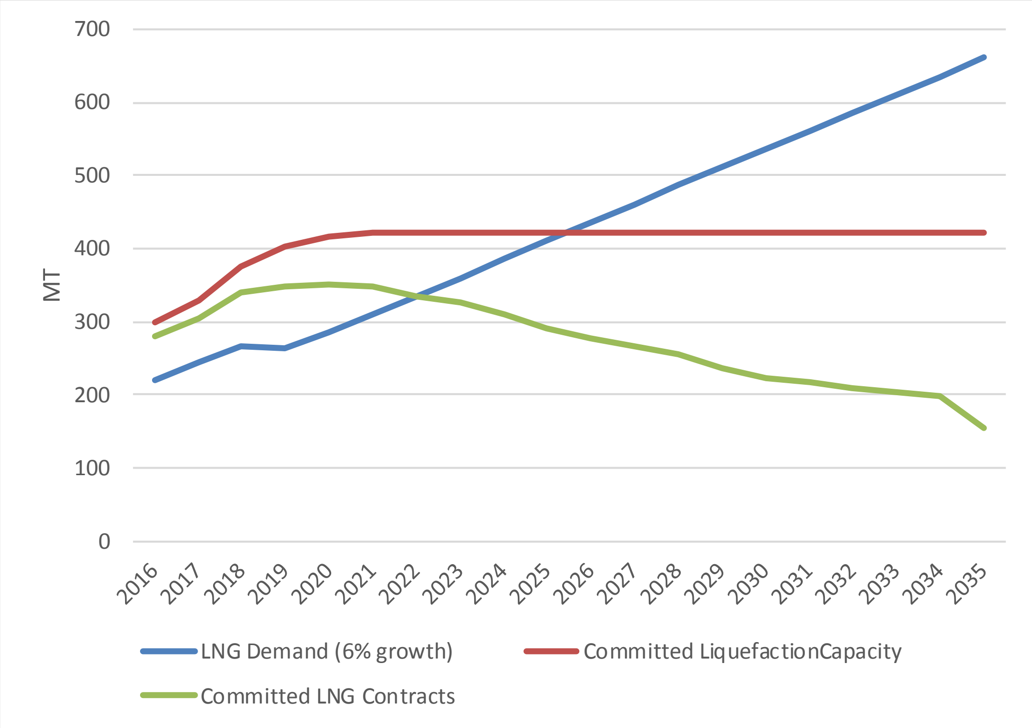


Sources: Brent – Investing.com; Japanese LNG Import – Ycharts.com; LNG Spot – Bloomberg

Further supply already under construction, predominantly from Western Australia and the US, has entered the market since 2016 and will continue to do so through to 2021, which will prolong market weakness and low prices into the early to mid-2020s. Figure 2-4 shows that existing and committed contracts will exceed demand until 2023 and that there will be liquefaction capacity surplus to requirements until 2027, though some of it may not have access to further gas resources.

[17] Egypt has withheld gas for its domestic market and Angola LNG has suffered technical failures.

Figure 2-4 Projected LNG Demand vs Contracts and Liquefaction Capacity



Sources: The LNG Industry, GIIGNL Annual Report 2016

2.1.7 LNG contract 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. Since then however the oil price has fallen as low as $US30/bbl, at which the LNG contract price is just $US4.20/mmbtu (Table 2-3), 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 $US8/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.

Contract prices and netback values in each of the AEMO Scenarios are presented in Table 2-3.

Table 2-3 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

2.2 Global LNG Demand-Supply Model

Since preparing the 2016 NGFR LNG Projections, LGA has developed a global LNG demand-supply model (RMMLNG[18]) which will be used to frame the aggregate Queensland LNG production scenarios in the context of global LNG demand-supply. The model estimates Queensland LNG production in the context of global LNG demand-supply and different model scenarios compatible with the AEMO oil price scenarios will define the Queensland LNG production scenarios. This analysis will focus on answering questions regarding Queensland LNG's role in managing the short-term LNG surplus and meeting longer term LNG supply requirements.

2.2.1 LNG Model Outline

The global LNG market is represented as competition among 20 regional LNG producers to meet the supply growth requirements of buyers in 10 linked regions[19], defined in Appendix A. This level of aggregation matches the widespread, public availability of the necessary market data, such as gas reserves, production and shipping costs etc. Initial supply contracts as in Figure 2-4 are entered as data. Supplier competition is modelled as a Nash Cournot game[20], however parameters can be adjusted to make market behaviour more competitive.

[18] Market Model Global LNG
[19] This is the beta version, future versions will cater for greater disaggregation
[20] Limited competition in which competitors maximise their profits subject only to limits imposed by others

2.2.1.1 Demand

Forecast LNG demand in the ten regions is as projected in Figure 2-2. Model realism is increased by including significant competition to LNG from Russian pipeline exports, in two of the regions, Europe and China, where the regional demand modelled is total gas demand less domestic gas supply and other less significant pipeline imports, such as from North Africa (in Europe) and Central Asia (in China). Russian pipeline exports to these two regions are included as a competing "LNG" producer, with pipeline costs replacing shipping costs.

To facilitate demand-supply balancing, forecast demand is assumed to have linear price sensitivity about the prices assumed in the forecasts.

2.2.1.2 Supply

In RMMLNG the LNG producers compete to develop new liquefaction and gas production facilities to meet new contract requirements, if any. There is a single tier of competition among producers who are assumed to control two tiers of production: liquefaction; and gas production. This is a valid model for most LNG producers, with the exception of US projects which acquire gas from a competitive wholesale market at hub prices.

The model starts with existing and committed capacity and contracts (as in Figure 2-4) and works through year by year adding additional capacity and contracts as required to match demand, according to the Nash Cournot solution. The model operates as if capacity can be added instantly, whereas in reality LNG projects spend four years in construction and several more in planning. For greater realism, no capacity is permitted to be added over the first three years (except that already under construction, which is included in data, as in Figure 2-4) and capacity subsequently added is assumed to be constructed over the previous four years, with perfect foresight as to demand. Mismatched development can be modelled by running a "variation" scenario as described in Appendix A.5.

Gas production contracts and capacity extend from the year they are created for set periods up to twenty years. Liquefaction capacity extends from the year it is created for twenty years.

Capacity costs and availability obey the following rules:

Figure 2-5 RMMLNG Liquefaction and Production Capacity Modelling Rules

	Liquefaction Capacity		Gas Production Capacity	
	Existing	**New Development**	**Existing**	**New Development**
Cost	Short Run Marginal	Long Run Marginal	Short Run Marginal	Long Run Marginal
Availability	Twenty years +	Twenty years +	Remaining duration of associated contracts	New gas contract must use less than uncontracted reserves plus a reserves "rundown" margin

The model does standard gas accounting to keep track of both reserves remaining and reserves already committed to contracts, so that new gas production capacity and contracts are properly constrained. Future reserve additions can also be included. The model also has the facilities to:

- Separate new liquefaction into brownfields – lower cost, sharing some existing facilities – and greenfields, with completely new facilities. Brownfields costs are assumed to be 70% of the costs of full plant construction.
- Separate gas reserves into two separate cost tranches, which are typically allocated to 2P reserves and 2C resources respectively.

The assumed short and long run costs assumed for the 20 producers that are modelled are listed in Table A 1.

The model includes the costs of shipping and regasification (to reflect competition with Russian pipeline gas). Shipping costs are optimised on an ex-post basis, after the Nash-Cournot liquefaction and production solution has been obtained.

To facilitate more detailed analysis of the role of Queensland LNG exports in the global market, in this version of RMMLNG the Australian LNG exports are split into Queensland and WA/NT. For countries where the LNG producers are not regional monopolies, RMMLNG can replicate the competitive effects of multiple producers by assuming the producer behaves as a joint venture of two or more parties selling separately. The oligopoly Nash-Cournot solution can be replaced with a competitive least cost solution by applying this to all producers, with multi-party JVs.

2.2.1.3 Outputs

The RMMLNG model produces a range of prices and quantities:

- Annual marginal price. This is the annual market balancing price and is a proxy for the LNG spot price in each region. It should be slightly higher than actual spot prices because regasification costs are included and shipping discounts are not considered. As noted in the previous section, modelled prices are the outcomes of perfect planning foresight and scenarios reflect long term trends rather than real market variations.
- Annual new contract price. This is the balancing price in years when new contracts are entered. It is set in $US/mmbtu
- Annual average price. This is the price averaged over all active contracts, new and old.
- Annual LNG production. Annual LNG produced and sold by each producer
- Annual new liquefaction and gas production capacity and LNG contracts. New quantities added.
- Gas reserves quantities. Gas reserves remaining and remaining and uncontracted
- Price adjusted annual demand quantities.

2.2.2 Scenario Guidance

RMMLNG can be used to define scenarios for Queensland LNG in aggregate simply by defining sets of model inputs and using Queensland LNG production outputs from the model. However, it is more informative to first consider in more general terms how Queensland LNG output is likely to respond to LNG market price stimuli.

At any market price[21], an LNG producer has a number of options: if the market price is below its short run operating costs (including shipping) then its economically rational option is to stop operating or cut back to a minimum level of production while avoiding future restart costs; if the market price is above its short run costs but below long run gas plus short run liquefaction costs, then its economically rational option is to operate existing plant but not expand or replace any capacity.

Table 2-4 illustrates the range of responses for Queensland LNG under two different assumptions regarding the long-run gas cost: (a) a low-cost assumption of $US4.05/mmbtu ($A5/GJ); and (b) a high-cost assumption of $US5.67/mmbtu ($A7/GJ). These match the AEMO 2017 GSOO assumptions regarding: (a) the average cost of undeveloped CSG in the LNG producers' fields; and (b) the cost of undeveloped CSG in the GLNG's fields. In the tables, the right hand of the price range is the sum of the relevant gas, liquefaction and shipping costs (the latter set at $US0.75mmbtu to Japan).

Table 2-4 Queensland LNG Responses to Market Prices, Low Long Run Gas Cost (Costs & Prices in $US/mmbtu)

Gas Cost		Liquefaction Cost			Japanese Market Price Range		
Short Run	Long Run	Short Run	Long Run Brownfield	Long Run Greenfield	From	To	Queensland LNG Responses
					$11.20	Over	Greenfield expansion to Gas Capacity limit
	$4.05			$6.41	$9.28	$11.20	Expand Gas & Liq. to Brownfield limit
	$4.05		$4.48		$6.61	$9.28	Expand Gas Cap to existing Liq. Cap
	$4.05	$1.81			$4.95	$6.61	Operate only, allow gas capacity to decline
$2.39		$1.81			$0.00	$4.95	Stop operating

[21] This assessment assumes that LNG producer decisions are influenced by LNG Market prices, which is true of spot and short-term trades. Producers with long-term oil price indexed contracts may respond differently or indirectly.

Table 2-5 Queensland LNG Responses to Market Prices, High Long Run Gas Cost (Costs & Prices in $US/mmbtu)

Gas Cost		Liquefaction Cost			Japanese Market Price Range		
Short Run	**Long Run**	**Short Run**	**Long Run Brownfield**	**Long Run Greenfield**	**From**	**To**	**Queensland LNG Responses**
					$12.82	Over	Greenfield expansion to Gas Capacity limit
	$5.67			$6.41	$10.90	$12.82	Expand Gas & Liq. to Brownfield limit
	$5.67		$4.48		$8.23	$10.90	Expand Gas Cap to existing Liq. Cap
	$5.67	$1.81			$4.95	$8.23	Operate only, allow gas capacity to decline
$2.39		$1.81			$0.00	$4.95	Stop operating

This analysis provides the following guidance about Queensland LNG export scenarios:

1. At current LNG spot prices of approximately $US6/mmbtu (Figure 2-3) the most logical strategy would be to export at current levels of 19-20 Mtpa but minimise further capacity investment, potentially allowing gas production capacity to decline, as in the Weak Scenario in the 2016 NGFR LNG Projections.

2. A Stop Operating Scenario is unlikely because the estimated $US4.95/mmbtu threshold is below current low Asian LNG spot prices on an annual average basis.

3. If further lower cost gas is available, when the LNG spot price exceeds $US6.50/mmbtu to US$7.00/mmbtu on a sustained basis, expansion of gas supply to export up to liquefaction capacity of 25.3 Mtpa is economic. If further gas is higher cost, the LNG spot price would need to exceed $US8.00/mmbtu to US$8.50/mmbtu. This is similar to the Neutral Scenario in the 2016 NGFR LNG Projections, though this was capped at 23.8 Mtpa, the level of contracts.

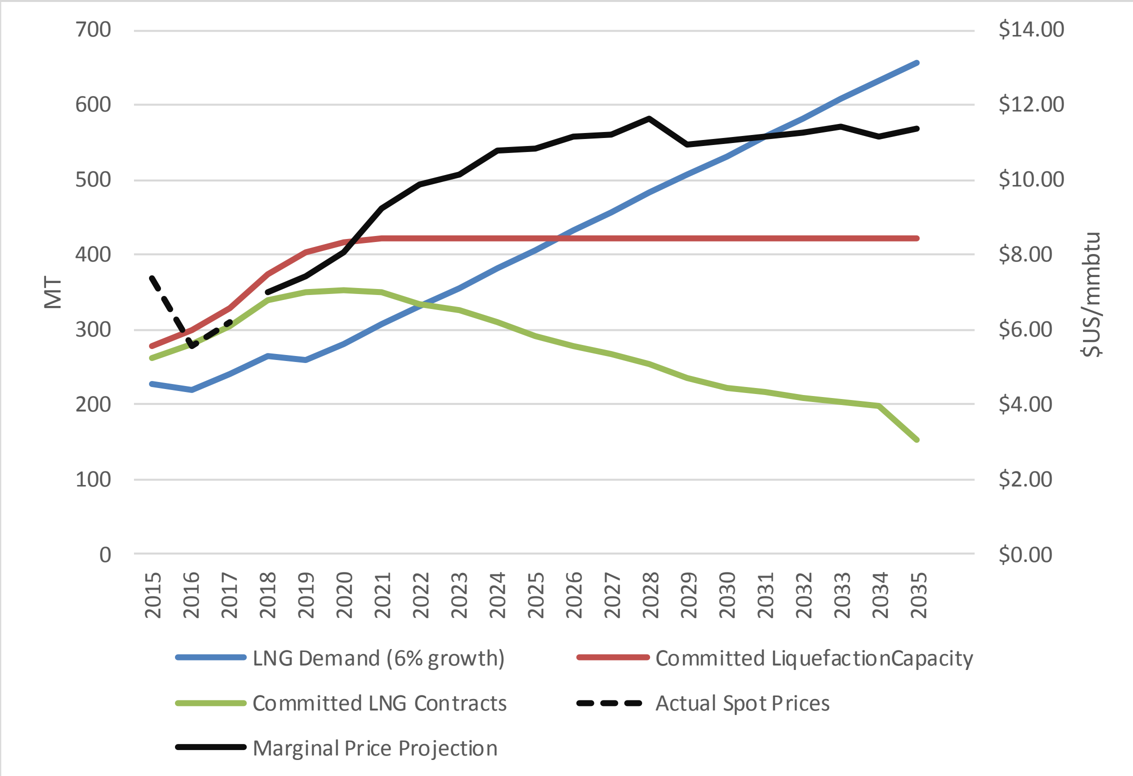
4. Brownfield liquefaction capacity expansion, assumed to be a further single train of approximately 4 Mtpa, would be justified only if LNG spot prices exceeded US$9.50/mmbtu on a sustained basis (low cost gas case) or $US11.00/mmbtu on a sustained basis (high cost gas case). This is similar to the Strong Scenario in the 2016 NGFR LNG Projections.

2.2.3 LNG Global Price and Queensland Production Projections

2.2.3.1 Medium LNG Price Case

Figure 2-6 illustrates a typical RMMLNG model LNG marginal price projection, using the global LNG demand forecast in Figure 2-2 and future supply as presented in Appendix A. In this projection, marginal prices rise from current lows as the gap between demand and contracted supply reduces, reaching a level of almost $US8/mmbtu by 2020 and $US10/mmbtu by 2023, sufficient to stimulate new capacity construction. (Note: costs for new supply to Japan, excluding from Qatar, range from approximately $US9.00/mmbtu for competitive brownfield projects to $US10-11/mmbtu for competitive greenfield projects. Refer to cost estimates in Appendices A.2 and A.3).

Figure 2-6 Sample LNG Price Projection (Marginal price, delivered to Japan, $US/mmbtu)

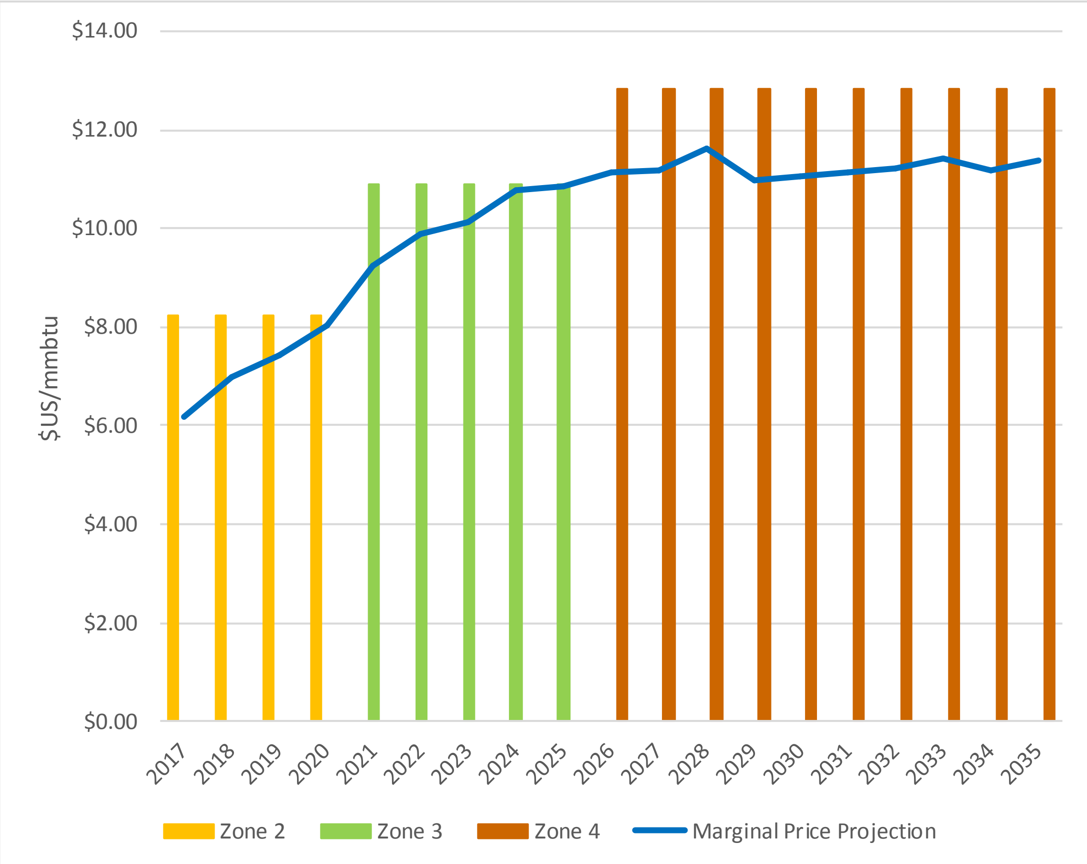


Queensland LNG responses to this “Medium” price path, for the high ($7/GJ) long-run cost of additional gas in Queensland, are presented in Figure 2-7. This suggests that:

- Up to 2020 the projects remain in Zone 2 (Operate Only) and have very limited incentive to expand production
- Between 2021 and 2025 the projects are in Zone 3 as the higher LNG prices provide an incentive to expand gas production capacity to match their existing liquefaction capacity
- From 2026 the projects have an incentive to construct brownfield liquefaction capacity and matching gas production capacity. However, the incentive is small and the expansion may be very limited.

RMMLNG LNG production projections for Queensland LNG for this price scenario for both the high ($7/GJ) and low ($5/GJ) long-run production costs are presented in Figure 2-8. It is noted that the impact of Queensland's long-run production costs on the global LNG price is very limited.

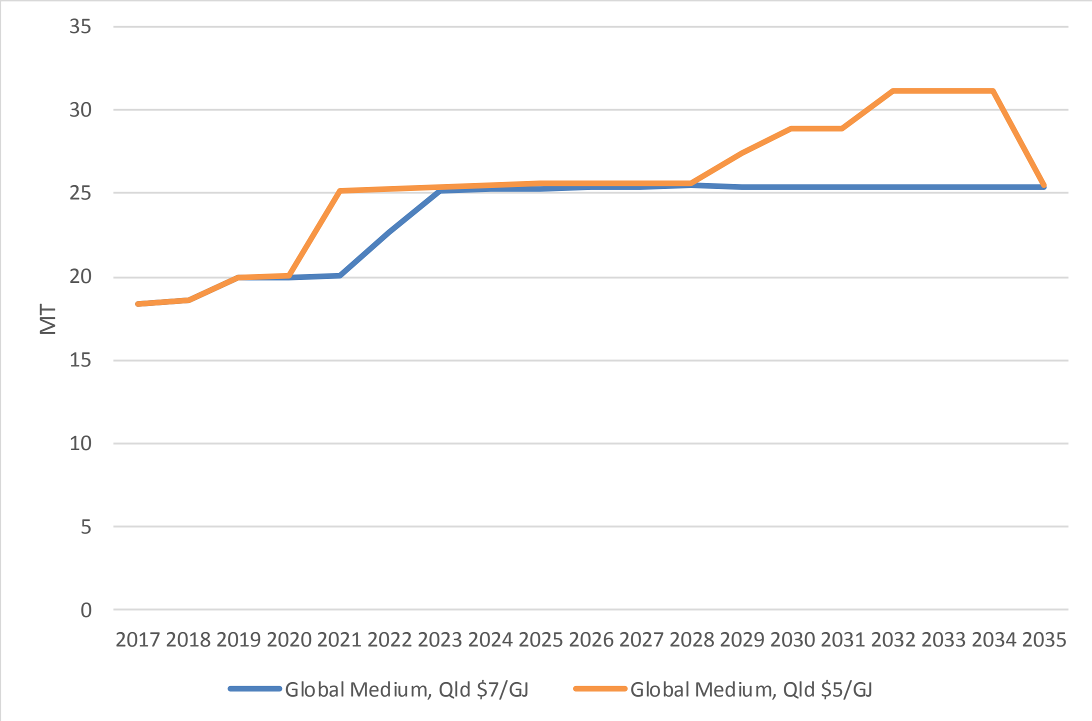
Figure 2-7 Queensland LNG Response to Medium LNG Price Projection



The projection for the high long-run cost confirms the above assessment, namely that Queensland's Nash-Cournot output is 20 Mtpa until 2021 (no production capacity expansion), then increases to 25 Mtpa from 2023. Brownfield expansion is does not occur.

At the lower long-run cost the projection is similar but the lower costs enable production to ramp up to 25 Mtpa two years earlier and enable Brownfield capacity to ramp up from 2029, though capacity is not reached until 2032.

Figure 2-8 Queensland LNG Production Projections for the Medium LNG Price Case (MT)



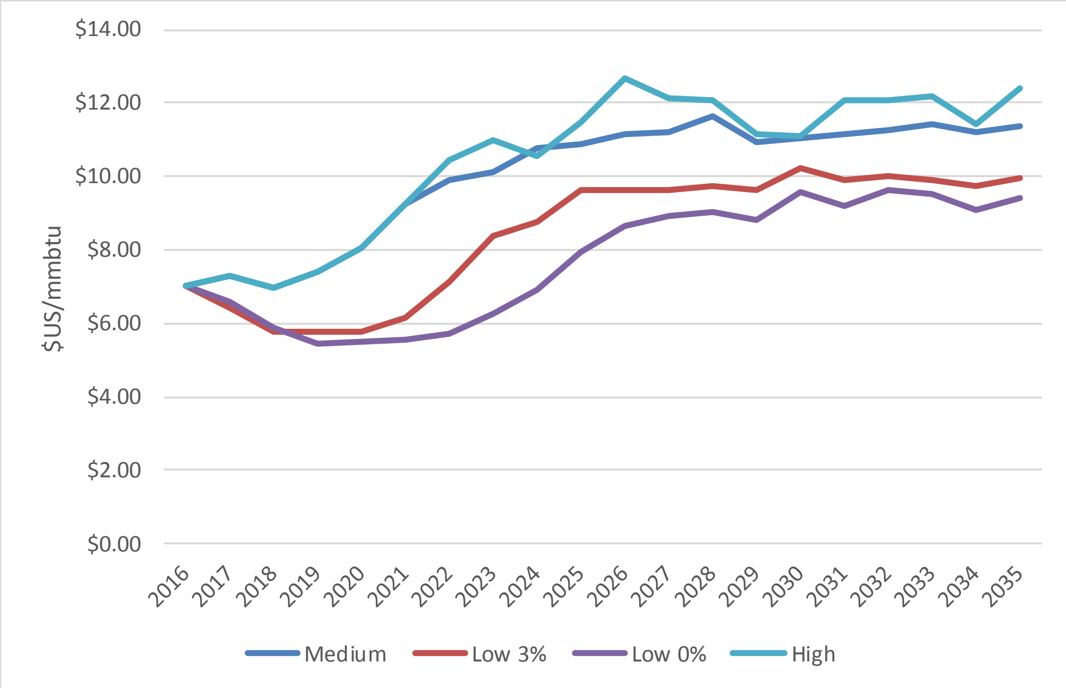
2.2.3.2 Low and High LNG Price Cases

It is evident from the long-run costs of LNG supply and from this analysis that in many other scenarios in which demand and supply reach and remain in equilibrium, marginal prices will also remain in Zones 3 and 4 for Queensland suppliers, with production outcomes similar to the above case. More extreme scenarios can only be generated in the following circumstances:

- Low marginal prices. This effectively requires demand to remain below the existing contracts/capacity for a more prolonged period.
- High marginal prices. This requires the lowest cost suppliers, such as Qatar, the US and others, to exclude themselves from the market, or for market parameters to change significantly, for example for production costs in other regions to escalate.

Two low cases and one high case constructed in this way are shown in Figure 2-9. The Low 3% price corresponds to 3% demand growth and the 0% price case to 0% demand growth. In relation to the AEMO oil price scenarios, in $/bbl terms the averages in these scenarios cover a range from $44/bbl in the low 0% case, through $57/bbl in the medium case, to $60/bbl in the high case.

Figure 2-9 Low and High LNG price cases (marginal prices delivered to Japan, $US/mmbtu)



RMMLNG LNG production projections for Queensland LNG for the high price scenario for both the high ($7/GJ) and low ($5/GJ) long-run production costs are presented in Figure 2-10. The projection corresponding to the high Queensland gas cost is very similar to the medium price high cost projection. However, the projection for the low Queensland gas cost includes some brownfield capacity ramping up from 2024. It is clear from the modelling of the medium and high LNG price cases that the development of the brownfield capacity is more dependent on the relative cost of the Queensland gas available than on the LNG market price.

RMMLNG LNG production projections for Queensland LNG for the two low price scenarios for the high ($7/GJ) long-run production costs are presented in Figure 2-11. Both projections start very low, with capacity being displaced by new US capacity, and reach points in the early 2020s at which replacing declining CSG capacity is not economic and output declines. In the 3% case this ends in 2025, at which time demand creates the need for more capacity, enabling Queensland's existing capacity to be fully utilised from 2029. In the 0% case the decline is reversed only in 2029 and full capacity utilisation is never reached.

Figure 2-10 Queensland LNG Production Projections for the High LNG Price Case (MT)

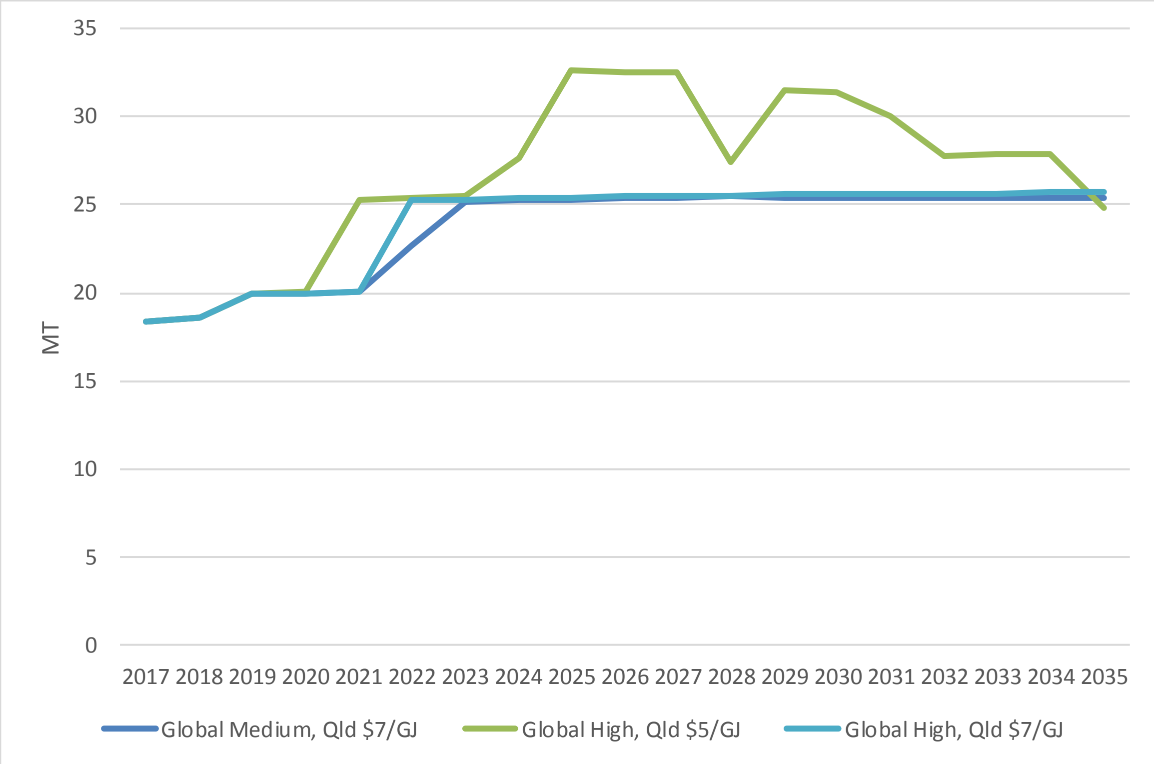
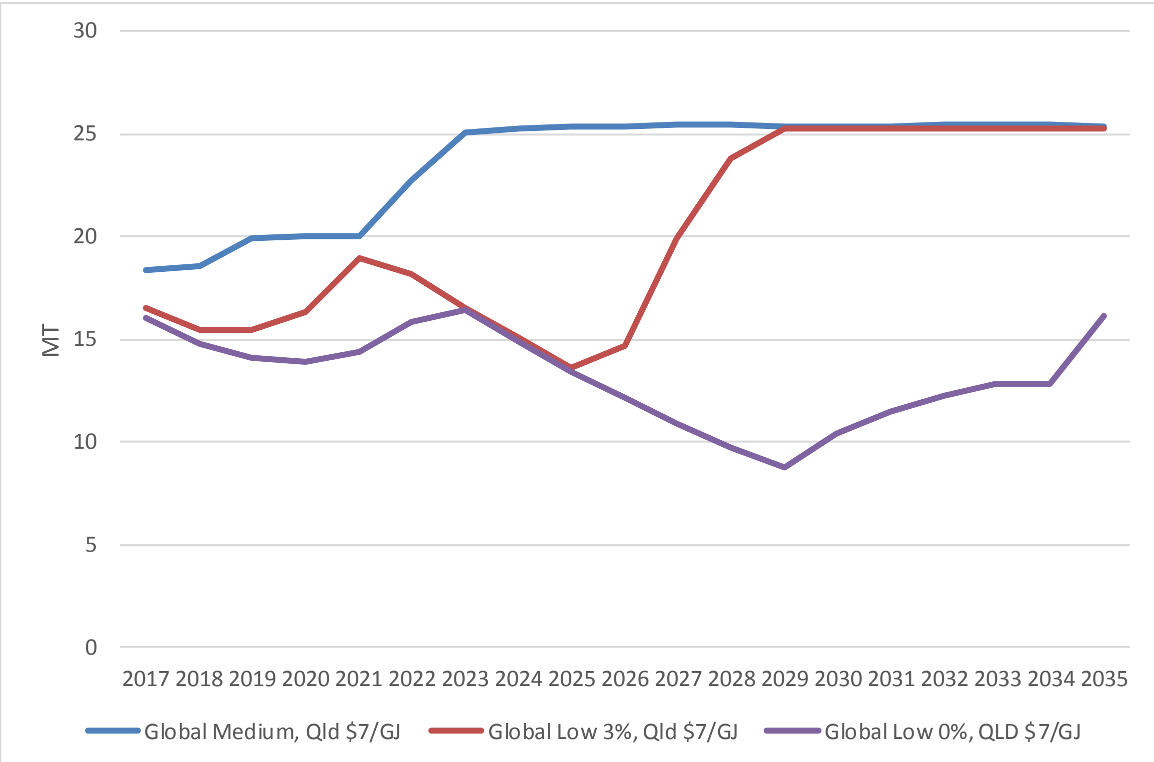


Figure 2-11 Queensland LNG Production Projections for the Low LNG Price Cases (MT)



2.3 Scenario selection

The above modelling suggests multiple candidates for each of the AEMO scenarios, depicted in Figure 2-12. The scenarios have been designed with variations either up (Neutral and Strong) or down (Weak). It is acknowledged that it is most likely that future 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.

The scenarios are:

Neutral – ramp from current production to capacity (25 Mtpa) by 2023, either very slowly to 2021 (Option 1) or more steadily over the period (Option 2). Option 1 is the modelling outcome in the medium LNG price case with additional Queensland gas at $A7/GJ.

Weak - remain at current production until 2021 and then decline to 14 Mtpa (Option 1) or decline steadily to 2023 and then decline to 9 Mtpa (Option 2). These are smoothed versions of the Low 3% and Low 0% modelled outcomes.

Strong – ramp from current production to capacity (25 Mtpa) by 2021, either slowly (Option 1) or more steadily (Option 2). Ramp further from 2026, to 29.5 Mtpa in Option 1 (brownfield capacity/7th train) or to 33 Mtpa in Option 2 (brownfield capacity/7th train plus debottlenecking, which is assumed to add 10% capacity). These are smoothed versions of the modelling outcome in the high LNG price case with additional Queensland gas at $A5/GJ.

2.3.1 LNG Consortia Projections

The projections provided to AEMO by the LNG Consortia (refer to section 1.3) are also depicted in Figure 2-12. These projections display the following relativities with LGA's candidate projections (options 1 and 2) in 2018 and 2019:

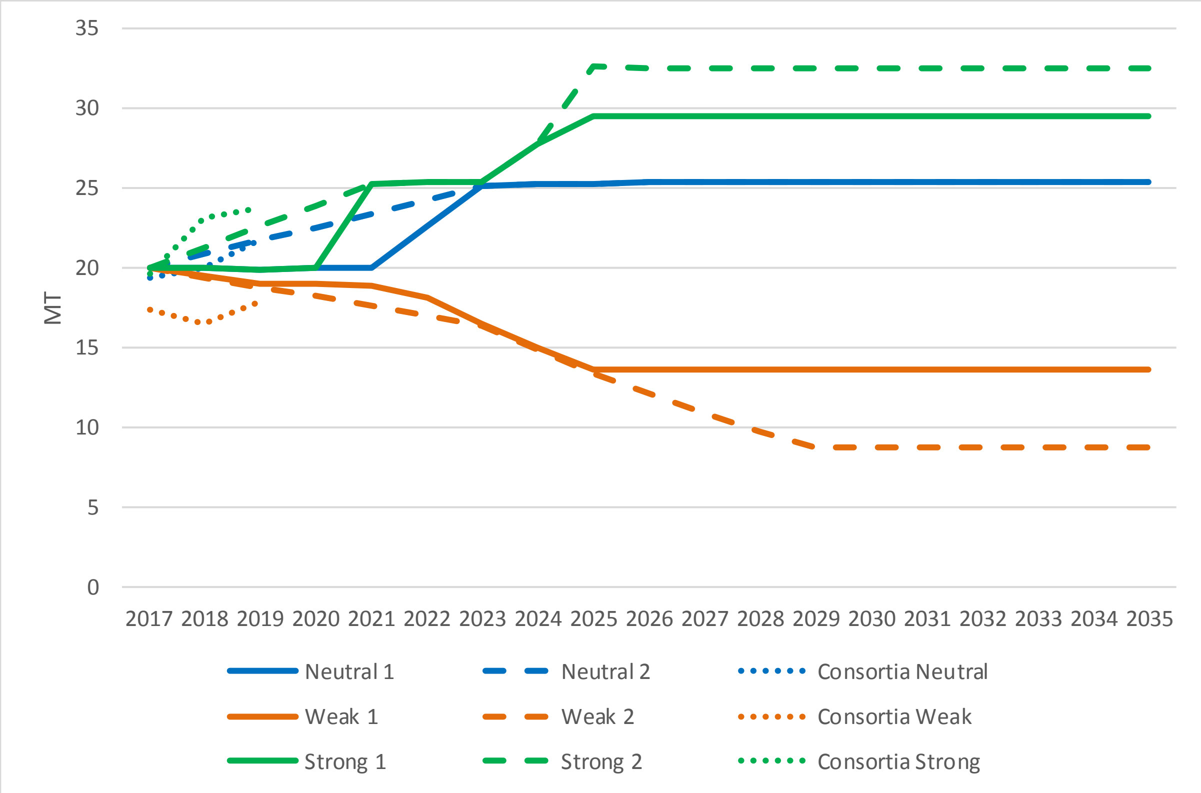
Neutral – Consortia 2018 is the same as LGA Neutral 1 and Consortia 2019 is the same as LGA Neutral 2.

Weak – Consortia 2018 is considerably lower than both LGA options but Consortia 2019 is trending towards both options.

Strong – the Consortia Projections ramp faster than both LGA options but are consistent with ramping to 25 Mtpa by 2021. Consortia 2019 is equal to the LGA Strong 2 value for 2020.

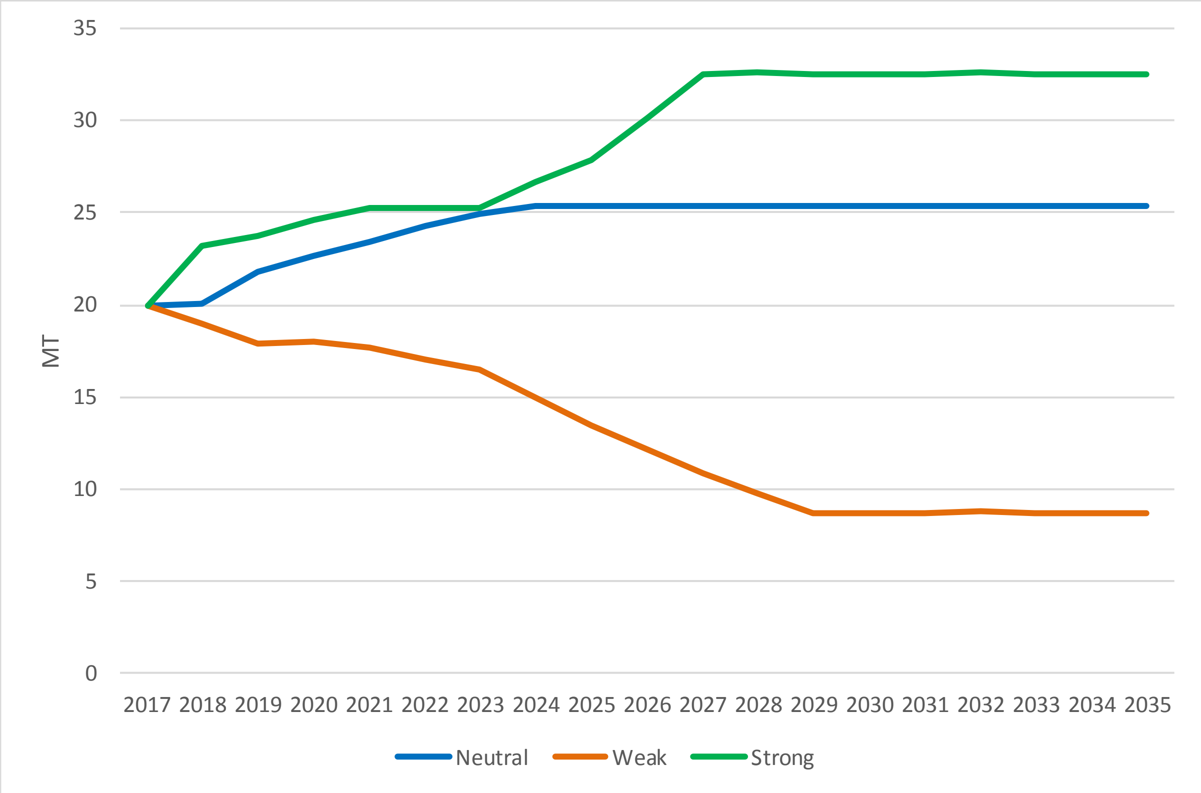
The 2017 value is now almost fixed. Estimated exports to 28th November 2017 are 18.2 Mtpa, which yields a prorated estimate for 2017 of 20.0 Mtpa, the same value as LGA's estimates based on actuals to 30th June 2017. LGA therefore believes it is appropriate to discount the Consortia estimates for 2017, particularly for the Weak Scenario, which has already been exceeded.

Figure 2-12 **Alternative Aggregate Queensland LNG Export Scenarios**



The final scenario selections for this draft report are shown in Figure 2-13. The 2017 values are all fixed at 20 Mtpa. The projections from 2018 are: Neutral – Option 1 for 2018 and Option 2 from 2019, consistent with the Consortia projections; Strong – Consortia projections for 2018 and 2019 merging with Option 2 by 2021; and Weak – declining linearly from 2017 to Consortia value for 2019 then trending to Option 2 after 2020.

Figure 2-13 Selected Queensland LNG Export Scenarios

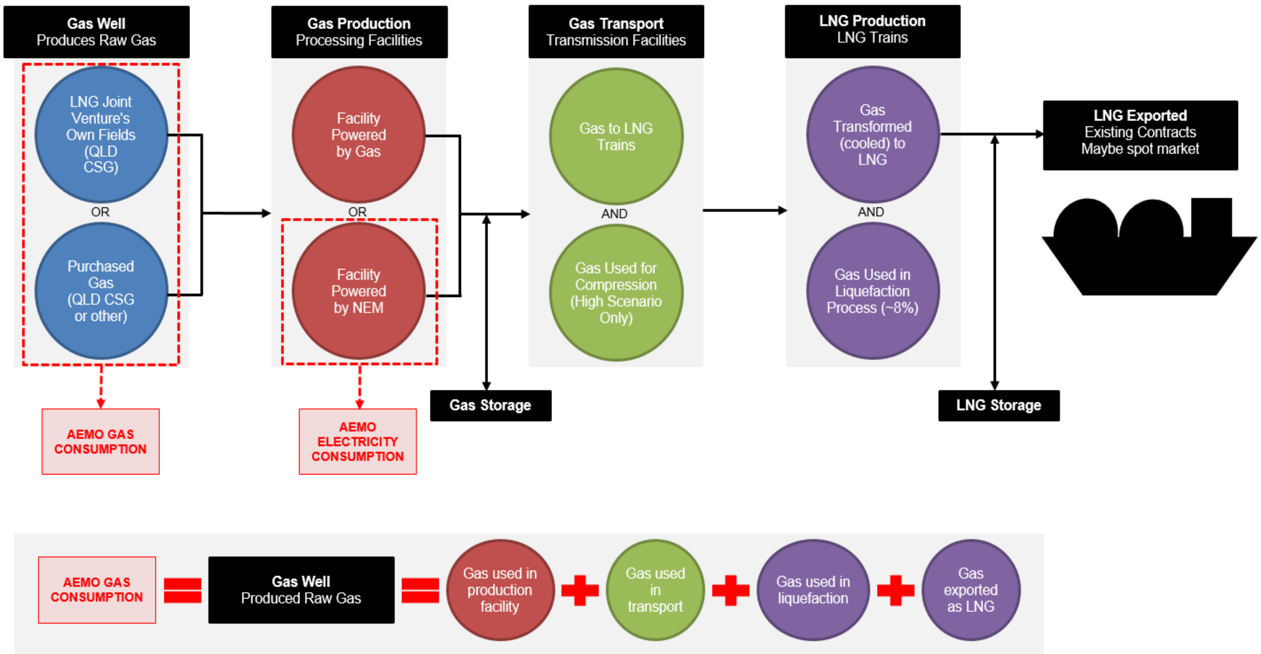


3. Gas and Electricity Usage Methodology

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 updated and improved versions of the methodologies applied to prepare the 2016 NGFR LNG 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 NGFR LNG Projections 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 80% 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, as in the 2016 NGFR LNG Projections, it is not considered in this report.

The sub-models used to estimate energy usage at each stage of the supply chain are straightforward and derived from: public information, including the previous 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 will not be constrained by gas supply capacity.

The underlying model is calculated 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 3.13.

Table 3-1 The LNG supply chain

Process	Energy used for	Cumulative gas volume to this point in the chain (backwards)	Grid supplied electricity
Export	Ignored, export volumes assumed to be on a 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

[22] CSG wells cannot be brought on-line instantaneously and instead have to be dewatered and ramped up to full production. Prior to first production of LNG some or all of ramp gas was surplus to LNG projects' requirements.
[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.

3.2 Historical data

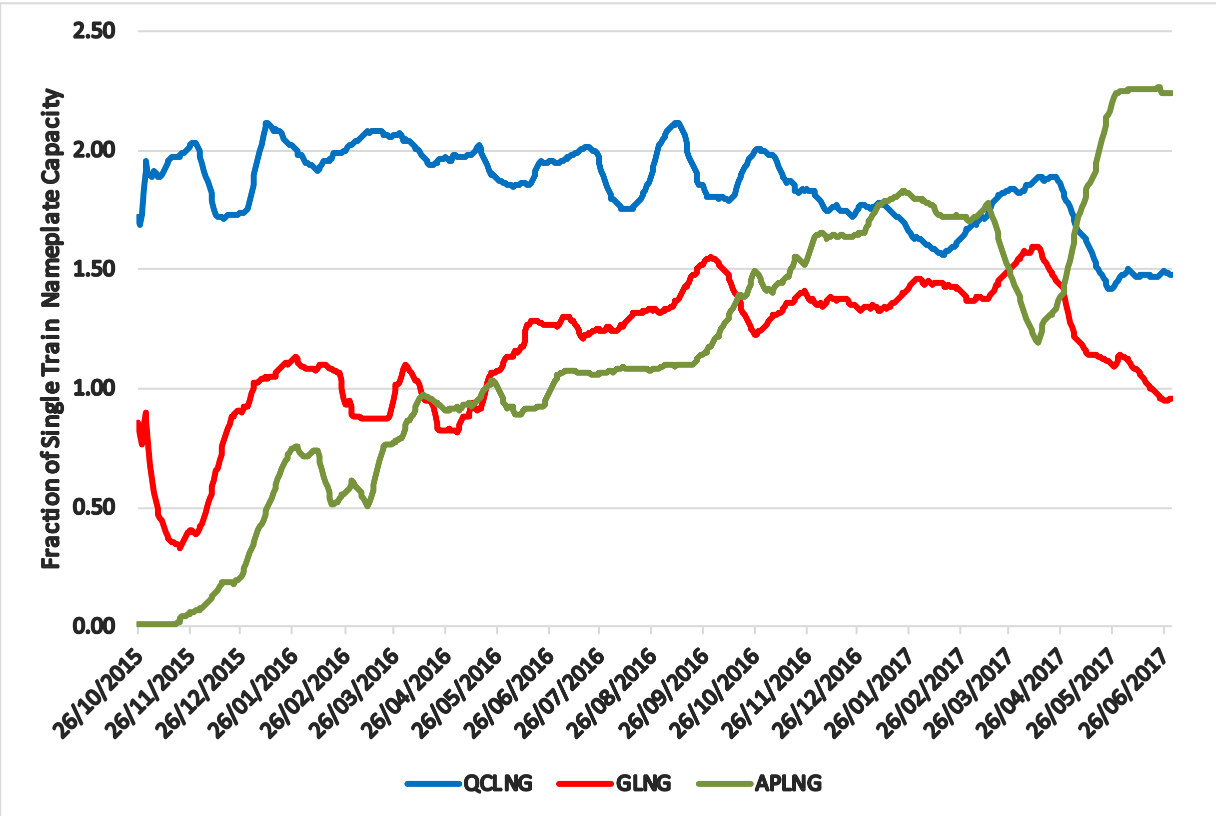
3.2.1 Exports

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 (the only data reported by QCLNG) but since October 2015 the AEMO Bulletin Board has reported daily gas flows on the LNG pipelines, equivalent to gas exported plus gas used in liquefaction.

Figure 3-2 shows LNG production rates for each plant since October 2015, expressed as fractions of single train capacities:

- Apart from shutting trains for maintenance, QCLNG operated both trains at capacity on average until the end of 2016 and has since operated slightly below capacity. QCLNG has regularly operated up to 10% above capacity.
- GLNG likewise operated its first train above nameplate capacity prior to May 2016, reaching 120% of capacity from time to time, but since the start of the second train in May 2016 combined utilisation has averaged only 1.3 trains and has peaked at 1.9 trains. This level of utilisation is broadly consistent with the slow ramp up of Train 2 anticipated in previous projections.

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

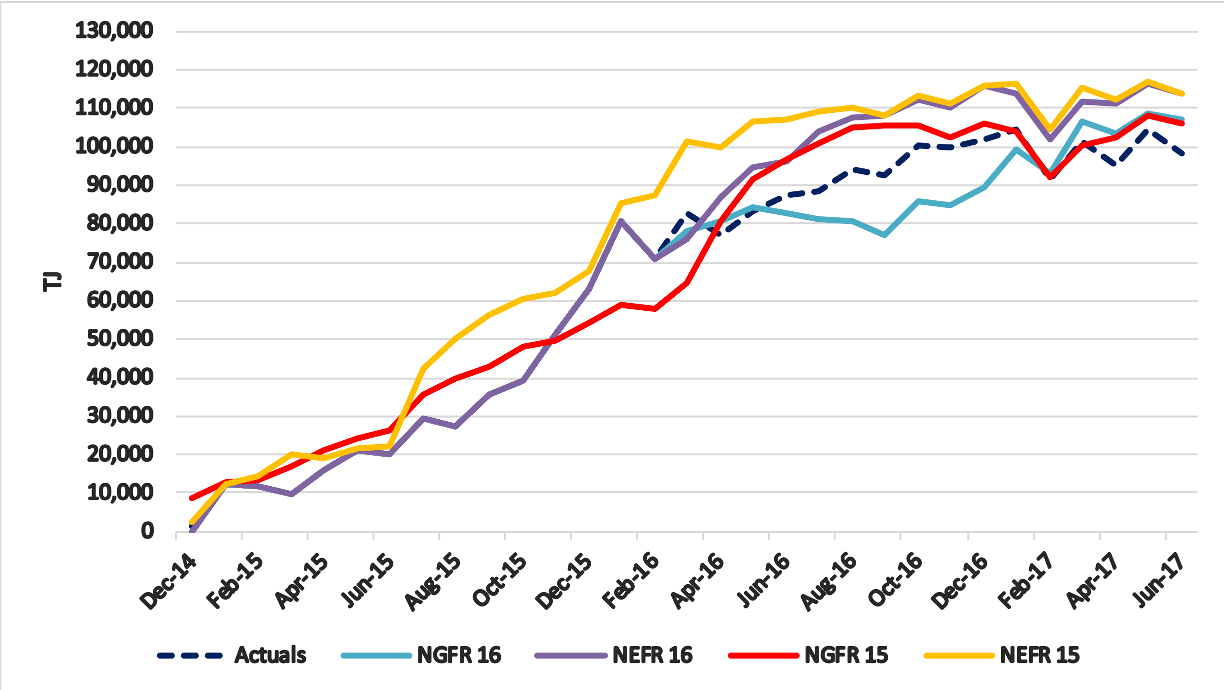


Source: AEMO Bulletin Board

- APLNG started up more conservatively but its combined train production averaged 112.5% of capacity during June 2017, as part of the 90-day operational phase of a project finance lenders test[25]. It appears that APLNG purchased gas from or swapped gas with the other projects during this period (see also Figure 3-5)

Figure 3-3 compares LGA's aggregate monthly projections from previous Projections with actual production to date. While there have been some forecasting errors of up to 20,000 TJ during the start-up phase, since all six trains became operational in late-2016 the most error in recent forecasts has been less than 8,000 TJ.

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



Source: LGA projections and AEMO Bulletin Board actuals

3.2.2 Gas production

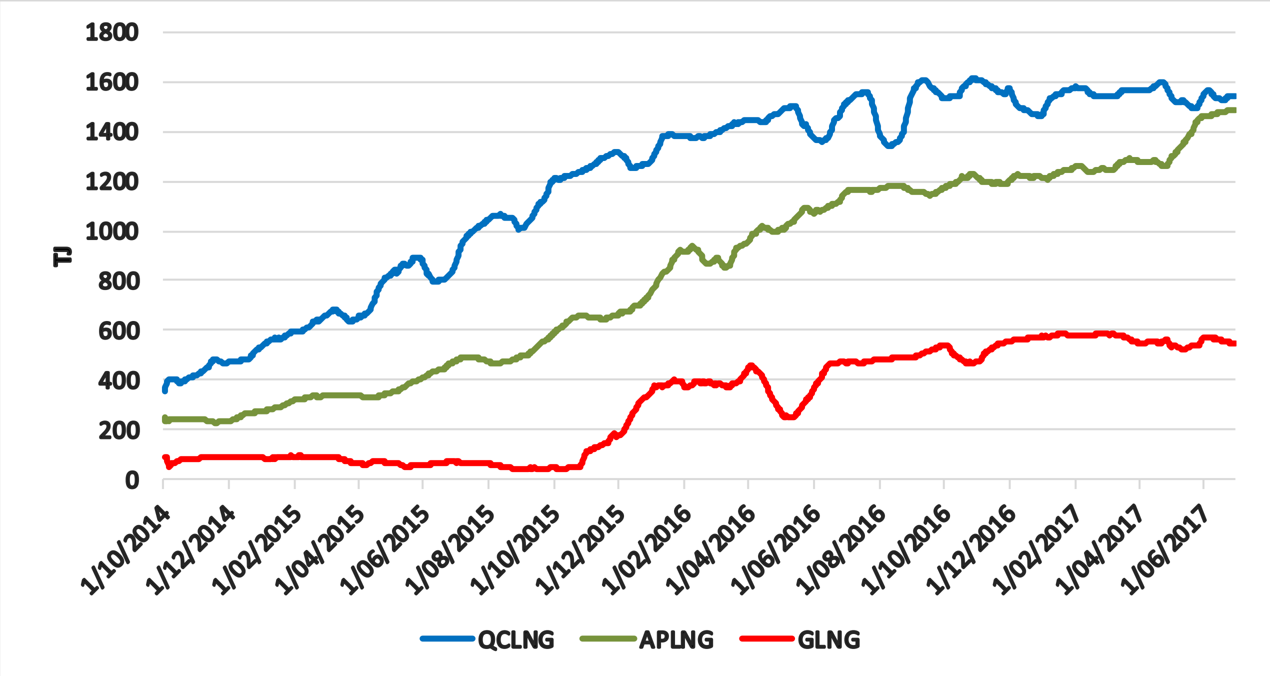
Reported production of CSG by the three projects[26] since October 2014 is shown in Figure 3-4. Since the initial production ramp up from late 2014 to late 2016 associated with initial LNG production at each of the six trains, CSG output by each of the operators has been relatively static. The surge in APLNG's output by approximately 200 TJ/d in April/May 2017 appears to be associated with APLNG's LNG production test discussed above and was due to higher usage of existing capacity at a number of fields rather than new capacity being introduced.

Total CSG production averaged 3,580 TJ/d during June 2017, up from 3,415 TJ/d in January 2017. The individual peaks for each CSG plant over the year to June 2017 add to 4,059 TJ/d and the total capacity of the existing plants, as registered on the AEMO Bulletin Board on 7th August 2017, is 4,575 TJ/d. Queensland gas production is supplemented by imports of up to 340 TJ/d via the South West Queensland pipeline, supply of which may be contingent on the demand-supply balance in South Eastern Australia.

The gas requirements of the 6 trains are approximately 4,100 TJ/d operating at capacity and 3,870 TJ/d operating at contracted levels. Queensland domestic demand which also relies upon the above supply is estimated to be in the range 300-400 TJ/d.

[25] Origin Energy Media Release 28 July 2017
[26] Production is reported on an operated basis and not an equity basis

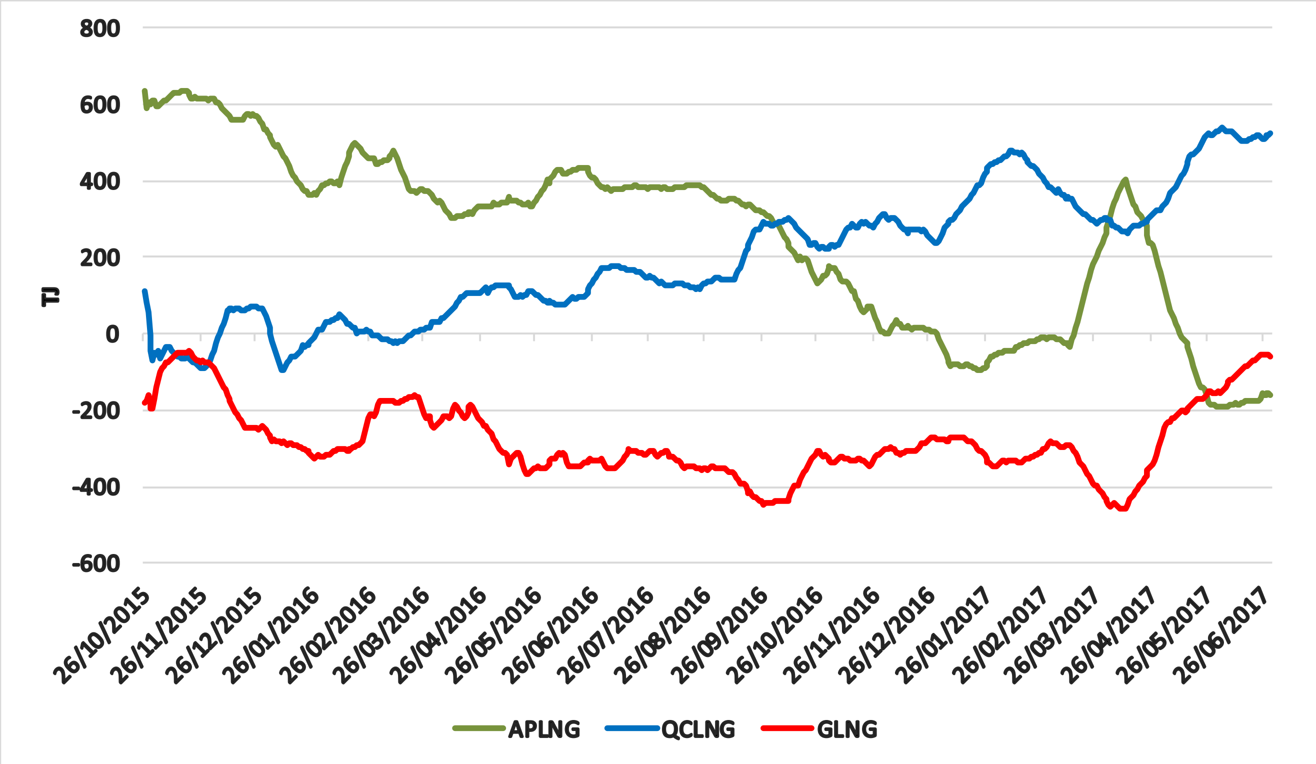
Figure 3-4 Monthly Average of Daily CSG Production (TJ/day)



Source: AEMO Gas Bulletin Board

In terms of net CSG production less LNG exports (Figure 3-5), each project has tended to be reasonably static. QCLNG's net increase and APLNG's net decline since the end of 2016 are due to APLNG taking up its equity share of CSG operated by QCLNG since the start-up of its (APLNG's) second train.

Figure 3-5 Net Monthly Average of Daily CSG production less LNG usage (TJ/day)

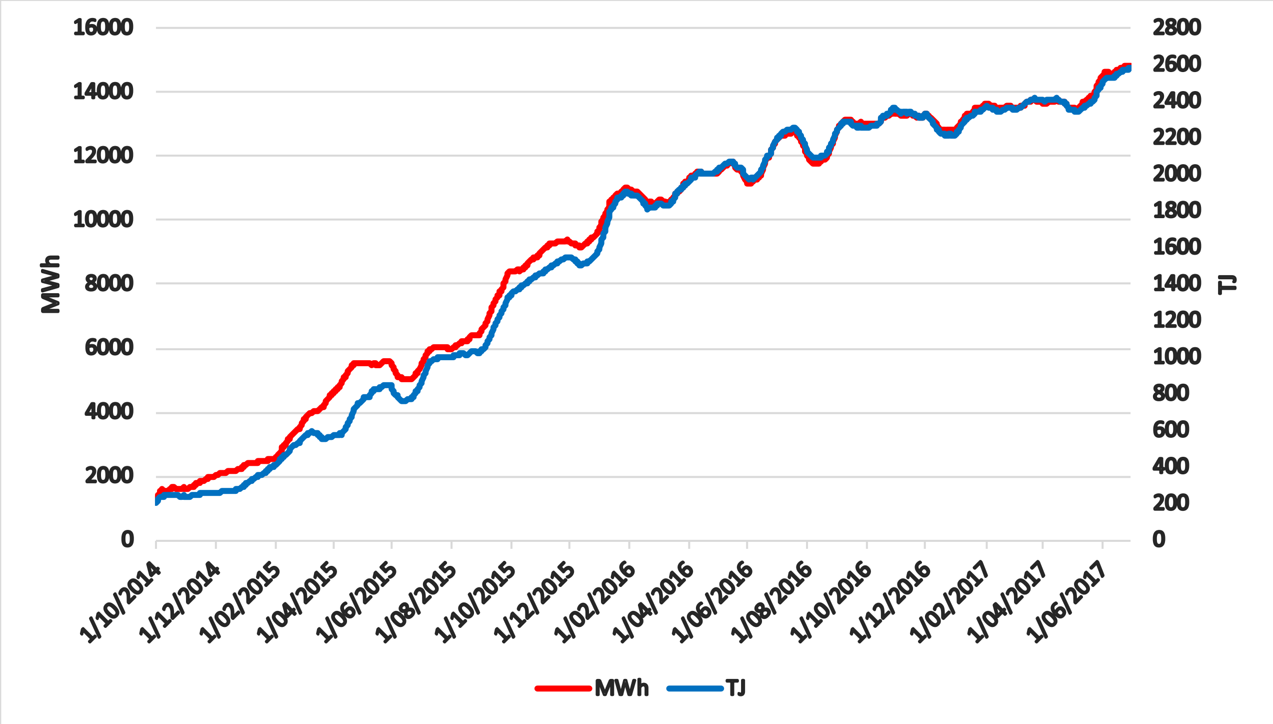


Source: AEMO Gas Bulletin Board

3.2.3 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 almost 15,000 MWh/day, averaging 620 MW in June 2017. 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 3.7.4.

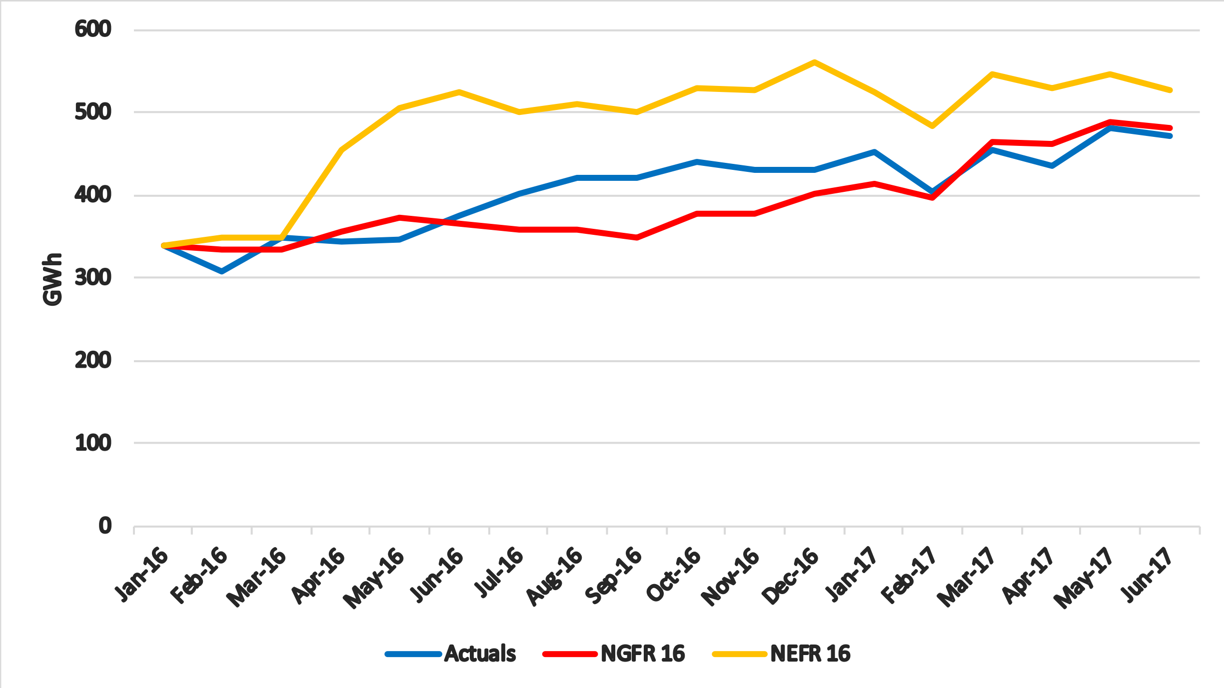
Figure 3-6 Monthly average of aggregate daily electricity usage vs monthly average of aggregate daily electricity powered gas production



Source: AEMO and Gas Bulletin Board, LGA analysis

Figure 3-7 compares LGA's aggregate monthly electricity usage projections from the 2016 NEFR and 2016 NGFR with actual production to date.

Figure 3-7 Projected vs Actual Monthly Electricity Usage (GWh)



Source: LGA projections and AEMO actuals

3.3 Gas exported

The assumed export levels in each scenario in selected years are summarised in Table 3-2.The Neutral Scenario export levels are set at the current capacities of the plants. In the Strong Scenario, the six existing trains produce at 110% of the current capacities and QCLNG adds a third train. In the Weak Scenario the decline in LNG production is shared equally among the projects.

Table 3-2 Assumed Export Levels in Selected years (Mt)

Scenario	Project	2020	2025	2030	2035
Neutral	QCLNG	7.5	8.5	8.5	8.5
	GLNG	6.2	7.8	7.8	7.8
	APLNG	8.5	9.0	9.0	9.0
	Total	**22.2**	**25.3**	**25.3**	**25.3**
Strong	QCLNG	8.2	9.1	14.0	14.0
	GLNG	7.1	8.4	8.6	8.6

Scenario	Project	2020	2025	2030	2035
	APLNG	8.9	9.7	9.9	9.9
	Total	**24.2**	**27.2**	**32.5**	**32.5**
Weak	QCLNG	6.4	5.0	3.1	3.1
	GLNG	5.2	4.1	2.5	2.5
	APLNG	6.4	5.0	3.1	3.1
	Total	**18.0**	**14.2**	8.7	8.7

Note: the GLNG production level of 6.2 Mt by 2020 is consistent with the most recent statement[27].

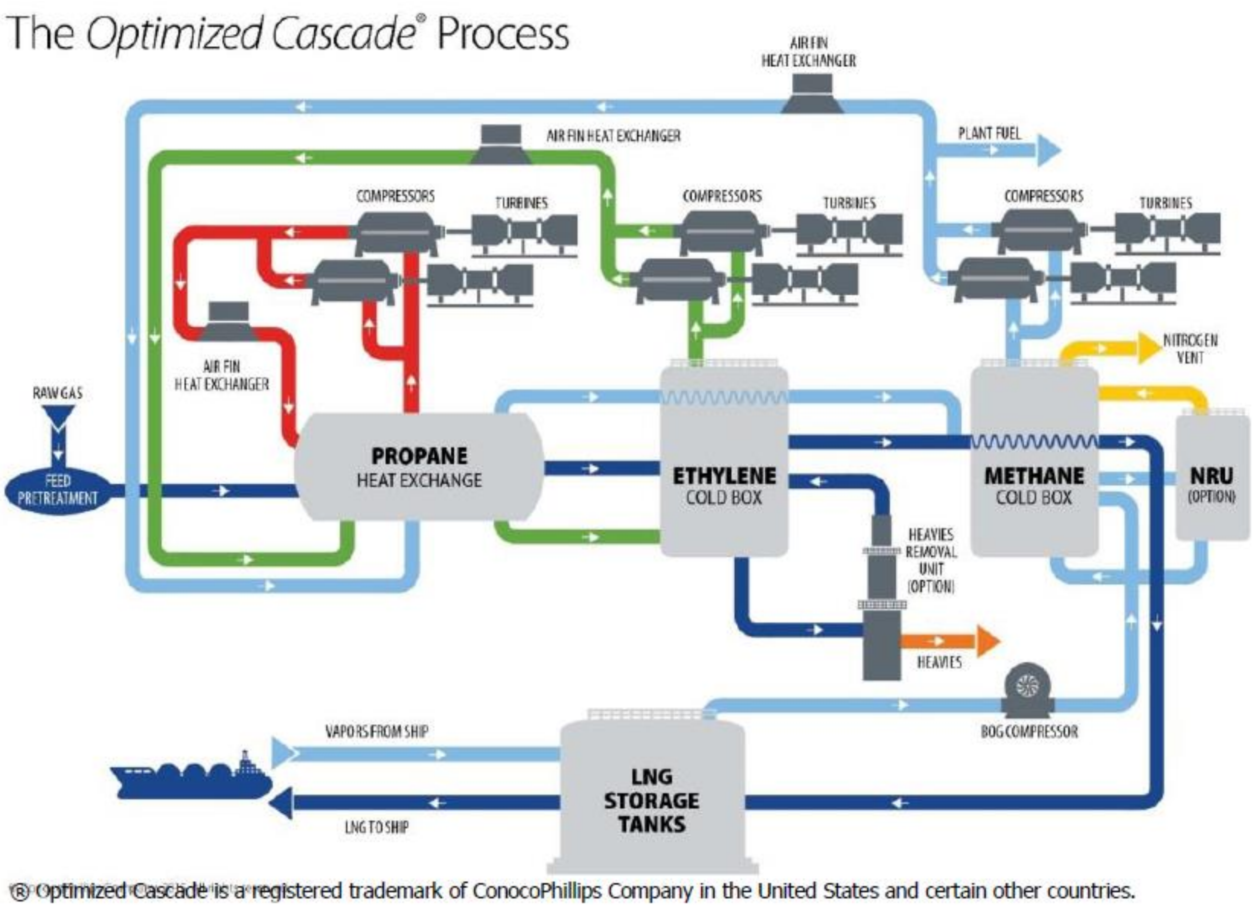
3.4 Energy used in LNG production (liquefaction)

3.4.1 Energy sources

All three Gladstone LNG plants have been built to the same Conoco Philips Optimised Cascade design by Bechtel, using LM2500+G4 aeroderivative gas turbines as refrigeration/compression drivers with power augmentation by inlet air chilling[28]. All plant power is therefore provided by gas taken from the plant inlet gas stream.

[27] Santos Shareholder Review 2016, 22/02/2017
[28] Successfully Delivering Curtis Island LNG Projects. Paper 429 presented by Bechtel and Conoco Philips at LNG18, Perth, April 2016.

Figure 3-8 Curtis Island Liquefaction Plant Outline



Source: Successfully Delivering Curtis Island LNG Projects. Paper 429 presented by Bechtel and Conoco Philips at LNG18, Perth, April 2016

3.4.2 Liquefaction gas usage

Previous LGA LNG projections have used an LNG plant efficiency of 92.6%, derived from an APLNG reference source. However, with seven quarters of actual LNG production data for GLNG and APLNG from Santos' and Origin's quarterly activity/production reports, which can be compared with Bulletin Board data on gas received, it is now more appropriate to use the actual plant efficiencies (Table 3-3 – it is noted that the efficiency derived from Origin's 2Q 17 data is anomalously high and this data is omitted from the average). QCLNG's operator, Shell, does not report activities at the level of disaggregation required to estimate QCLNG's efficiency, which is therefore assumed to be the same as that of APLNG's very similar plant.

The efficiencies used in the projections are: APLNG, 91%; GLNG, 90% ramping to 91% as production increases; QCLNG, 91%. The seasonality of efficiency used in the previous projections is not evident in the actual data and is no longer used.

These changes will result in increases in the projections of gas used in production compared to the 2016 NGFR Projections, at the same LNG export levels.

Table 3-3 Estimated actual plant efficiencies

	GLNG			APLNG		
Quarter	LNG Produced (PJ)	Gas Received (PJ)	LNG Plant Efficiency	LNG Produced (PJ)	Gas Received (PJ)	LNG Plant Efficiency
4Q 15	29.9	34.0	87.9%	2.5	8.5	29.9%
1Q 16	52.7	59.3	88.9%	40.7	49.0	83.1%
2Q 16	54.5	60.6	89.9%	57.9	64.3	90.0%
3Q 16	71.5	80.1	89.3%	67.6	75.2	89.9%
4Q 16	69.4	77.0	90.1%	96.3	106.9	90.1%
1Q 17	75.2	83.2	90.4%	98.7	108.2	91.2%
2Q 17	59.0	66.0	89.4%	120.9	124.1	97.4%
Average FY17	68.8	76.6	89.8%	87.6	96.8	90.5%

Sources: GLNG - Santos Quarterly Activity Reports; APLNG – Origin Energy Quarterly Production Reports.

3.5 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 3-9 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 3-9 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

[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.

	QCLNG	GLNG[29]	APLNG[30]
Capacity without compression[32] (TJ/d)	1,588	1,430	1,560
Peak delivery to 30-06-17 (TJ/d)	1,549	1,208	1,689

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. This assumption has been validated by comparing volumes of gas received with transmission volumes from the Gas Bulletin Board.
- 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 Strong 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.

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.

[32] Standing capacities listed on the AEMO Bulletin Board

Table 3-5 Comparison of volumes transported and received

	GLNG		APLNG	
Quarter	Gas Transported (PJ)	Gas Received (PJ)	Gas Transported (PJ)	Gas Received (PJ)
4Q 15	29.4	34.0	8.4	8.5
1Q 16	59.4	59.3	47.5	49.0
2Q 16	61.8	60.6	64.3	64.3
3Q 16	80.3	80.1	75.0	75.2
4Q 16	77.2	77.0	106.4	106.9
1Q 17	83.3	83.2	107.9	108.2
2Q 17	64.4	66.0	132.5	124.1

Sources: Gas Transported – Gas Bulletin Board; Gas Received as per Table 3-3

3.6 Energy used in gas storage

Underground gas storage is used by two of the LNG projects, QCLNG and GLNG, 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.

Usage of gas storage is likely to be very limited under steady state operation, hence LGA has determined to exclude storage from the modelling, consistent with previous projections. 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.

3.7 Energy used in gas supply

3.7.1 Introduction

This section addresses gas supply for the purpose of differentiating between gas sourced from fields that are powered by electricity and those powered by gas. Assumptions regarding the availability of the gas from each source are made clear but no attempt has been made to assess whether some of the sources may be diverted to the domestic market under the ADGSM.

3.7.2 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 sources of these resources for each project will be their equity reserves in Queensland CSG, for which updated values are presented in Table 3-6. Total reserves have decreased by 2,789 PJ (7%) compared to the values at 31st December 2015 used in the 2016 NGFR LNG Projections report. This reflects production of 1,200 PJ over the period plus reserves downgrades equivalent to 1,589 PJ.

Current total reserves are sufficient to meet 20 years of domestic demand (approximately 3,000 PJ) plus 36,000 PJ for the six existing trains for 20 years. Further reserves are required to support the 7th train in the Strong Scenario however.

Table 3-6 LNG project equity and operated Queensland CSG 2P reserves remaining as at 31 December 2016 (PJ)

	Equity	Operated
QCLNG	9,273	10,845
GLNG	5,216	5,990
APLNG	13,552	11,205
Arrow Energy	9,256	10,771
Others	3,511	1,996
Total	40,808	40,808

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

GLNG and QCLNG also rely upon third party gas supplied under long term contracts. Current estimates of gas volumes are reported in Table 3-7. No new contracts were entered between compilation of the 2016 NGFR LNG Projections report and the very recent contract between Arrow and QCLNG, which is not included in the table. QCLNG's total contract volume remaining after 31st December 2016 is estimated to be 537 PJ and GLNG's is estimated to be 2578 PJ.

Complementary to the first contract, it has been assumed that APLNG will take 70 PJ of its equity share in the QCLNG operated fields, from 2017. 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 p.a. of its equity gas at Fairview.

[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 3-7 LNG project contracts with third party suppliers

	Seller	Operator	Buyer	Source	Delivery Point	Term (years) & start	Total Volume (PJ)	Annual Volume (PJ)
1	APLNG	QCLNG	QCLNG	Surat CSG	Field	20 2015	640	95 falling to 25 after 2016
2	Santos	Santos	GLNG	Cooper primarily	Wallumbilla?	15 2015	750	50
3	AGL	QCLNG	QCLNG	Surat CSG	Field	3	75	25
4	Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	10 2015	365	36.5
5	Origin	Unknown	QCLNG	OE Portfolio	Wallumbilla	2	30	15
6	Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	5 2016	100 Firm 94 Sellers option	20-39
7	Stanwell	Unknown	GLNG?	Wallumbilla?	Wallumbilla?	1.75 2015	53	30
8	AGL	QCLNG?	GLNG	Surat CSG	Wallumbilla?	7 2015	32	4.6
9	Meridian JV	Westside	GLNG	Bowen CSG	GLNG Pipeline	20 2016	445	24
10	Senex	GLNG	GLNG	Surat CSG	GLNG Pipeline	20 2018	Up to 365	Up to 18.3
11	AGL	QCLNG	GLNG	Surat CSG	Wallumbilla	11 2017	254	Up to 34

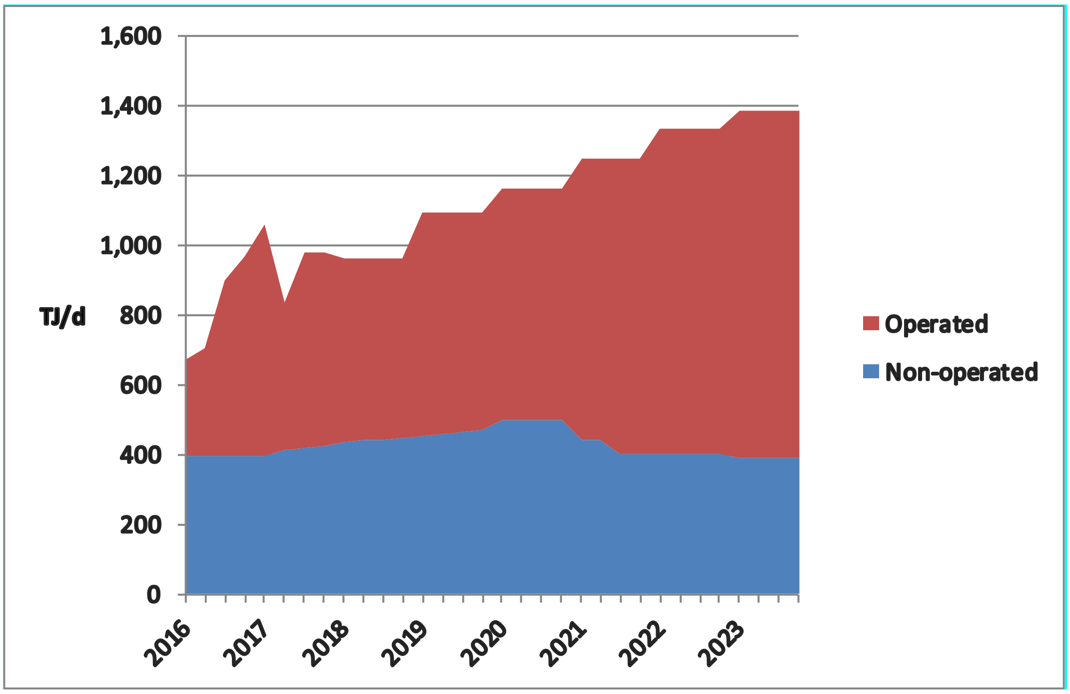
Sources: Company media statements. A question mark indicates that the relevant information has not been published and that the value in the table is the best estimate.

3.7.3 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 3-10 illustrates the application of this approach to GLNG in the Neutral Scenario.

Figure 3-10 GLNG Neutral Scenario gas allocation to operated and non-operated – average daily supply



3.7.4 Allocation of operated gas requirements to production areas

For each LNG project, the projected operated gas requirement is allocated to the LNG project's gas production areas pro-rata to their production capacities, which are generally proportional to the reserves in the related fields. For each LNG project, an initial allocation is used, followed by one which incorporates known supply extension projects, such as Charlie (QCLNG) and Arcadia (GLNG). For the purposes of calculating gas and electricity use, future as yet unknown extensions are taken to be located in the existing production areas, even though this is unlikely to be true in all cases.

Table 3-8 Gas production areas and processing plant capacities

QCLNG			GLNG			APLNG		
Production Area	**Gas Processing Plant**	**Capacity**	**Production Area**	**Gas Processing Plant**	**Capacity**	**Production Area**	**Gas Processing Plant**	**Capacity**
Southern	Ruby Jo	499	**Fairview**	Hub 1-3 + Scotia	170	**Condabri**	North	180
	Jordan	455		Hubs 4 & 5	430		Central	180
				Arcadia	140		South	180
	Total	**954**		**Total**	**740**		**Total**	**540**
Central	Kenya	180	**Roma**	Hub 2	184	**NW Surat**	Combabula	300
	Berwyndale South	144		Expansion	270		Reedy Creek	180
	Bellevue	227					Eurombah Creek	180
	Total	**551**		**Total**	**454**		**Total**	**660**
Northern	Woleebee Creek	517				**Orana**	Talinga	25
	Charlie	200					Orana	200
	Total	**717**					**Total**	**225**

Sources: LNG Project reports; AEMO Gas Bulletin Board

3.7.5 Gas field and processing plant energy usage

3.7.5.1 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 in 2015 with LNG project representatives in conjunction with AEMO, LGA has a reasonable 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 wellhead whereas QCLNG and APLNG are using gas engines.
- All electricity for the above is now believed to be sourced from the Queensland electricity grid, though some was initially sourced from onsite gas turbines[34].
- 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 3-9). 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 late 2017. For APLNG however, because some new plants will be gas driven, the electricity powered proportion may decline.

Table 3-9 Initial average proportions of gas and electricity powered compression at processing plants

	QCLNG	GLNG	APLNG
Gas Powered	6%	30%	0%
Electricity Powered	94%	70%	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.

[34] 2016 NGFR LNG Projections.

For gas-driven plant the values in Table 3-10 are as in the 2016 NGFR LNG Projections Report, because with more extensive electrification it has become difficult to reliably separate the gas-driven plant data.

For energy usage from electrically driven plant AEMO has provided LGA with updated actual electricity usage data for the period October 2014 to June 2017 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 3-11). Analysis of daily electricity usage plotted against daily gas production (Figure 3-12) suggests that the current value of 5.72 MWh/TJ is a reasonable estimate of the lower bound of usage, towards which it is expected that usage will converge. This is 1.2% (0.07 MWh/TJ) higher than the estimate used in the 2016 NGFR LNG Projections Report. This figure converts to 2.06% of energy produced.

The above electricity usage covers only the processing plant compression and wellhead 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.

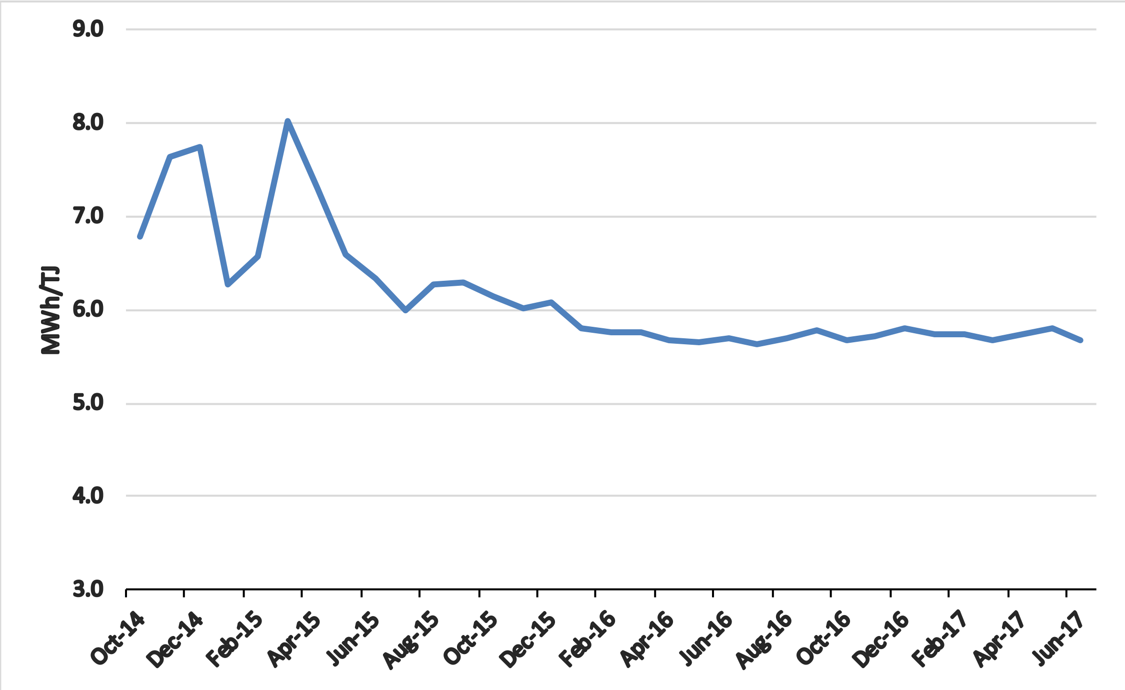
For GLNG it is estimated that wellhead usage will be the electricity equivalent of the above 1% for gas driven well heads i.e. 0.37% of energy produced. This makes GLNG's total electricity usage 2.43% of energy produced, which is reflected in Table 3-10.

Table 3-10 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	2.06%	2.43%	2.06%
Electricity driven plant	Gas	1%	0%	1%

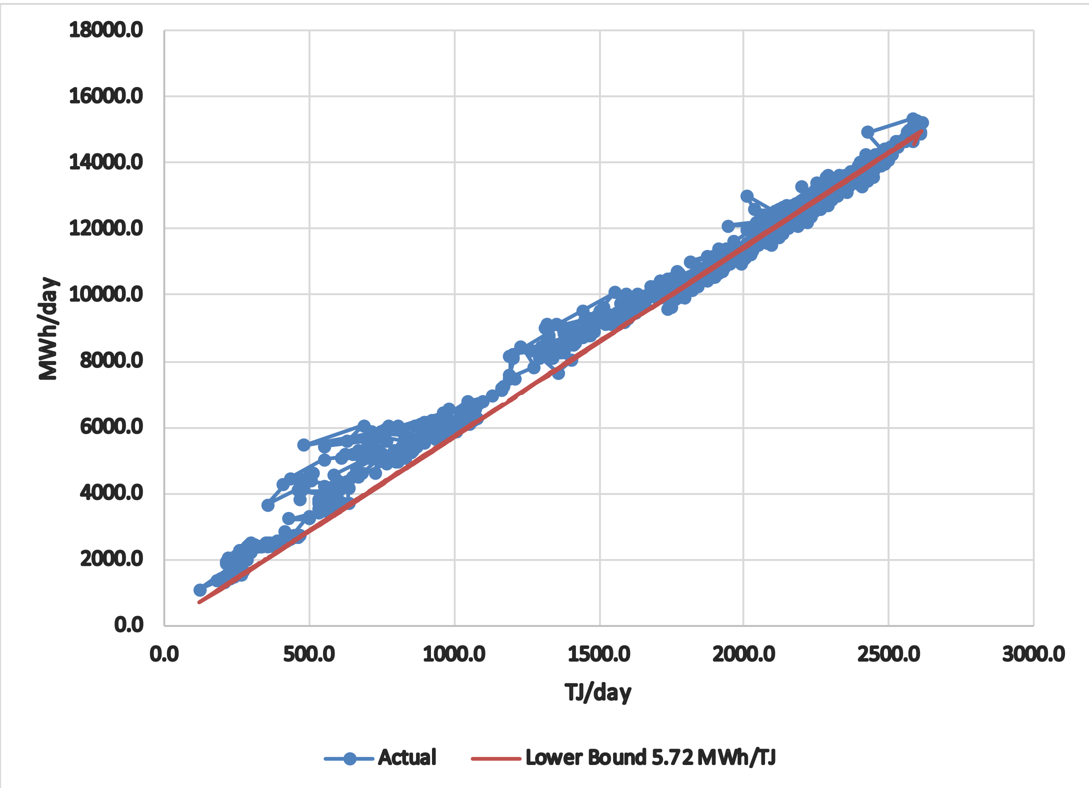
Sources: Queensland Department of Natural Resources and Mines; AEMO; Reference 1

Figure 3-11 Electricity usage per unit of gas production, aggregate of fields in production (MWh/TJ)



Sources: AEMO, Gas Bulletin Board

Figure 3-12 Aggregate daily electricity usage vs gas production



Sources: AEMO, Gas Bulletin Board

3.7.5.2 Note

The above is correct for the majority of electrically driven plants. However, recent data suggests that a small number of plants are operating at levels of electricity usage per TJ of gas production that are approximately 50% of the above, which is less than the theoretical minimum.

The low electricity usage suggests that these plants are using other power sources for gas compression at its plants, even though LGA had previously been advised this was not occurring.

For the purposes of the projections LGA has assumed that these plants are using gas direct drive for 50% of their plant power needs.

3.7.5.3 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 2016 NGFR LNG Projections report.

3.8 Estimates of peak gas and electricity demand

3.8.1 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 twenty months of Bulletin Board data on LNG pipeline volumes demonstrates this very clearly. As reported in Table 3-11, QCLNG's gas demand to date for its two trains has regularly peaked each month between 100% and 110% of nameplate plant capacity[35][36], in energy terms up to1549 TJ/d including gas used in liquefaction, while its load factor (average demand/peak demand) has varied between 76% and 94%. It is noted that QCLNG's peak utilisation is slightly less than its name plate pipeline capacity of 1588 TJ/d.

Table 3-11 LNG project actual demand patterns

	QCLNG		GLNG		APLNG		All Projects	
Period	Load Factor %	Peak % Nameplate	Load Factor %	Peak % Nameplate	Load Factor %	Peak % Nameplate	Load Factor %	Peak % Nameplate
Nov-15	95%	108%	41%	102%	20%	35%	78%	80%
Dec-15	83%	108%	81%	117%	35%	87%	73%	103%
Jan-16	94%	107%	91%	123%	79%	92%	91%	105%
Feb-16	96%	107%	84%	113%	60%	101%	90%	100%
Mar-16	97%	107%	92%	114%	80%	102%	93%	106%

[35] Nameplate capacities in MT terms are listed in Table 1-1
[36] It is common for LNG plants' actual capacities to exceed their nameplate capacities by 10-20%.

	QCLNG		GLNG		APLNG		All Projects	
Apr-16	94%	106%	74%	115%	87%	107%	91%	104%
May-16	88%	108%	79%	72%	84%	113%	90%	89%
Jun-16	95%	104%	87%	74%	92%	113%	93%	94%
Jul-16	84%	110%	81%	78%	99%	110%	93%	92%
Aug-16	93%	109%	91%	74%	98%	113%	96%	95%
Sep-16	84%	110%	84%	94%	82%	73%	94%	81%
Oct-16	94%	108%	71%	90%	75%	97%	95%	84%
Nov-16	89%	105%	85%	82%	87%	95%	95%	87%
Dec-16	85%	106%	82%	83%	86%	98%	94%	86%
Jan-17	94%	88%	91%	81%	95%	95%	96%	86%
Feb-17	82%	102%	87%	80%	92%	95%	96%	85%
Mar-17	90%	103%	83%	93%	68%	106%	92%	88%
Apr-17	90%	100%	81%	83%	70%	109%	92%	85%
May-17	87%	85%	88%	64%	100%	113%	95%	87%
Jun-17	82%	89%	91%	52%	98%	112%	94%	83%

GLNG's gas demand for its first operating train similarly peaked at 123% of nameplate plant capacity but since the start of the second train in May 2016 GLNG has averaged only 79% of plant capacity. In energy terms GLNG has used up to 1208 TJ/d including gas used in liquefaction, well below its pipeline capacity. Its load factor of has ranged from 71% to 91%.

APLNG's gas demand has peaked at 113% of nameplate plant capacity for both trains during its recent test period. In energy terms APLNG has used up to 1689 TJ/d including gas used in liquefaction, more than 100 TJ/day above its nominal pipeline capacity. Its load factor of has ranged from 68% to 100%.

Load data for all three projects combined differs structurally from that of the individual projects. Since all six trains have been operating the aggregate peak has varied narrowly over the range 83% to 88% of total nameplate plant capacity, suggesting that at present there is only sufficient gas for approximately five trains. Aggregate load factor of has also ranged narrowly, from 92% to 96%.

The above analysis suggests that peak gas demand modelling should have two components:

1. Individual plant peak gas demand, based on a percentage of nameplate plant capacity

2. Combined aggregate peak gas demand, based on a load factor calculation.

On the gas supply side, Table 3-12 details peak supply that:

a) has been demonstrated up to June 2017, i.e. the Roma Zone is the sum of the maxima produced by each Roma Zone plant independently (this capacity has increased by approximately 300 TJ/d since June 2016);

b) is planned capacity at existing plants, according to Bulletin Board data (the precise date this will become available is unknown);

c) includes capacity at planned plants under construction, including those of Meridian (65 TJ/d) and Senex (50 TJ/d), which are assumed to be available on or before 01 January 2019.

Table 3-12 Queensland Peak Gas Supply (TJ/d)

	Roma Zone	SWQP	Silver Springs	Roma Storage	Gross Supply
Demonstrated at 30-06-2017	4,059	250	40	100	4,449
Existing Plant at Planned Capacities	4,575	250	40	100	4,965
Planned Plant at Capacity, available by 01-01-2019	5,046	250	40	100	5,436

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 394 TJ/d in 2016-17) nor of CSG-direct connected GPGs, is detailed in Table 3-13. It is noted that the total nameplate pipeline capacity, which by virtue of interconnections is effectively shared among the projects, is 4,578 TJ/d, which is greater than the planned gas plant capacity and would therefore not be a constraining factor on peak demand.

Table 3-13 Net peak gas supply available for LNG (TJ/d)

		# LNG Trains Supplied at	
	Net Peak Supply for LNG (TJ/d)	**110%of nameplate capacity**	**100%of nameplate capacity**
Demonstrated at 30-06-2017	4,055	5.3	5.8
Existing Plant at Planned Capacity	4,571	6.0	6.6
Planned Plant at Capacity, available 01-01-2019	5,042	6.6	7.2

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.

For the purposes of the Neutral Scenario projections it is assumed that the individual plant peaks remain at 110% of nameplate capacity and the aggregate peak is determined by a load factor of 93%. For the Strong Scenario, with higher levels of aggregate production, it is assumed that the individual plant peaks reduce to 105% of nameplate capacity and the aggregate peak is determined by a load factor of 95%.

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 2018 to 2023 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.

3.8.2 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 3.7.4).

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?

  The proportion of the LNG Projects' CSG that is from electrically driven plant is currently averaging 80%, but a regression analysis of the most recent 12 months data (electrically driven vs total CSG) shows that electrically driven plant is used more flexibly than gas driven plant (the correlation coefficient is 92% with a negative constant of -406 TJ/day).

However, this is not a suitable model for predicting peak electricity driven plant output as it overpredicts this variable. The actual peak electricity driven plant output over this period was 2971 TJ, compared to predictions of 2995 TJ by this model and 2955 TJ by the simple average, which is closer to actual and therefore a more suitable peak demand model.

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

  Examination of electricity usage data for the past 12 months indicates that daily load factors at each plant average between 95% and 98%, with the aggregate also 98%. For forecasting purposes, a value of 98% is assumed for all plants, with zero diversity.

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.

3.9 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 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. On 14 April 2016, the ACCC granted conditional authorisation for five years. The condition requires the Applicants to publicly disclose maintenance schedule information that they have shared with one another, and to ensure that information remains accurate.

For the purposes of this study it is therefore assumed that this co-ordination ensures that no more than one train at a time undergoes scheduled maintenance, so 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 110% or more of capacity can offset a single plant going offline. Demand from the remaining five trains operating at 115% of capacity is only 114TJ/d to 229 TJ/d (3% to 5%) 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 capacity 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 115% capacity (5% above average in this scenario) is 448 TJ/d to 630 TJ/d (10% to 14%) 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

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

extent that the five trains online do not operate at capacity, minimum demand could be lower, though this is unlikely in this scenario.

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 the same as the average daily demand in this scenario.

In the Strong Scenario, minimum electricity demand is 90 MW (12%) less than the average daily demand in this scenario.

A comparison of peak, average and minimum demand in a representative year (2025) in the Neutral and Strong Scenarios is presented in Table 3-14.

Table 3-14 Comparison of Peak, Average and Minimum Demand in 2025

	Neutral Scenario		Strong Scenario	
	Gas (TJ/d)	Electricity (MW)	Gas (TJ/d)	Electricity (MW)
Peak	4,505	821	4,851	884
Average	4,189	774	4,608	854
Minimum	4,015	774	4,055	764

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

3.10.1 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 both the Neutral and Strong Scenarios. 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 on 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.

3.10.2 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 3-15. 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 3-15 Electricity grid prices at which centralised gas turbine compression power breaks even ($/MWh, $2017)

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

3.11 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 5-6 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 $833/MWh[38] to $2,000/MWh. Consequently, GPPs would be unlikely to voluntarily curtail electricity usage at pool prices below this range.

- At prices well below this level it could become profitable for LNG projects to divert gas from LNG to gas fired electricity generation, where there is any unutilised generation capacity. The marginal cost of gas fired generation with gas at $12/GJ, the upper end of its value as LNG, would be approximately $97/MWh for a typical combined cycle plant and $158/MWh for a typical open cycle plant. At pool prices above these levels it could therefore be profitable for LNG projects to divert gas from LNG to generation, either in plants owned

[38]($5000/TJ)/(6MWh/TJ) = $833/MWh

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.

3.12 Confidence in the Neutral Scenario projections

The following table describes the levels of confidence LGA ascribes to the components of the neutral 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 neutral 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 3-16 Confidence in Neutral Scenario projections to 2020

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

3.13 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 – 2^{nd} month total – 1^{st} 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 – 2^{nd} month peak – 1^{st} 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 2016 NGFR LNG Projections (dashed lines). In all scenarios, there is a slower ramp up to the plateau level compared with the 2016 Projections, with most of this attributable to the alignment of the 2017 scenarios with current weak global LNG market conditions. The Strong scenario has the same plateau levels as in 2016 but the Neutral Scenario is 6% higher, reflecting production at nameplate capacity instead of contract levels.

The decline in the Weak Scenario starts earlier than in the 2016 projections – the decline is due to non-replacement of CSG production capacity due to low LNG prices.

It is noted that initial 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. Mothballing would not affect exports but could reduce peak gas and electricity demand.

Figure 4-1 Total LNG export projections

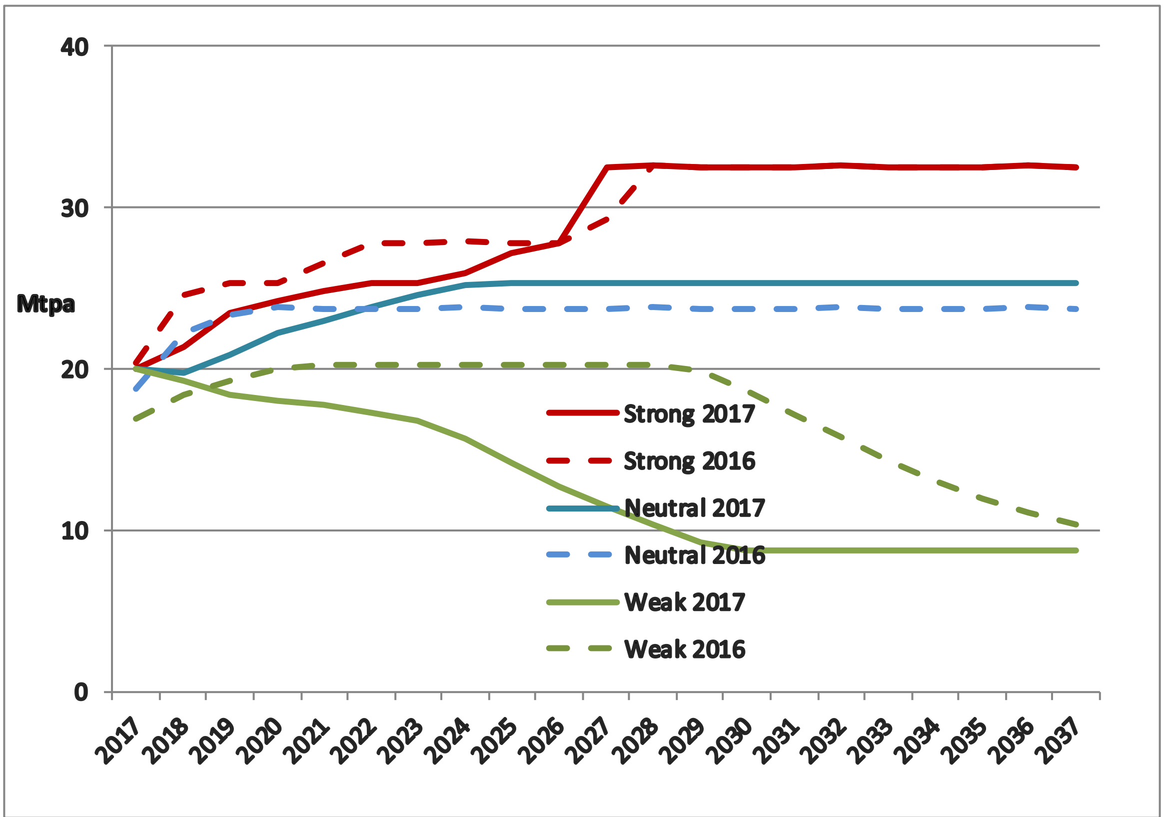


Figure 4-2 and Figure 4-3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production.

For gas usage, the significant increase in estimated gas used in 2017 compared to 2016 is due to the switch from theoretical unit usage rates for liquefaction to rates derived from actual production data (refer to section 3.4). The scenario relativities largely track the export relativities.

For electricity usage, the reduction in usage in 2017 compared to 2016 is mostly due to the lower usage in a small number of plants.

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

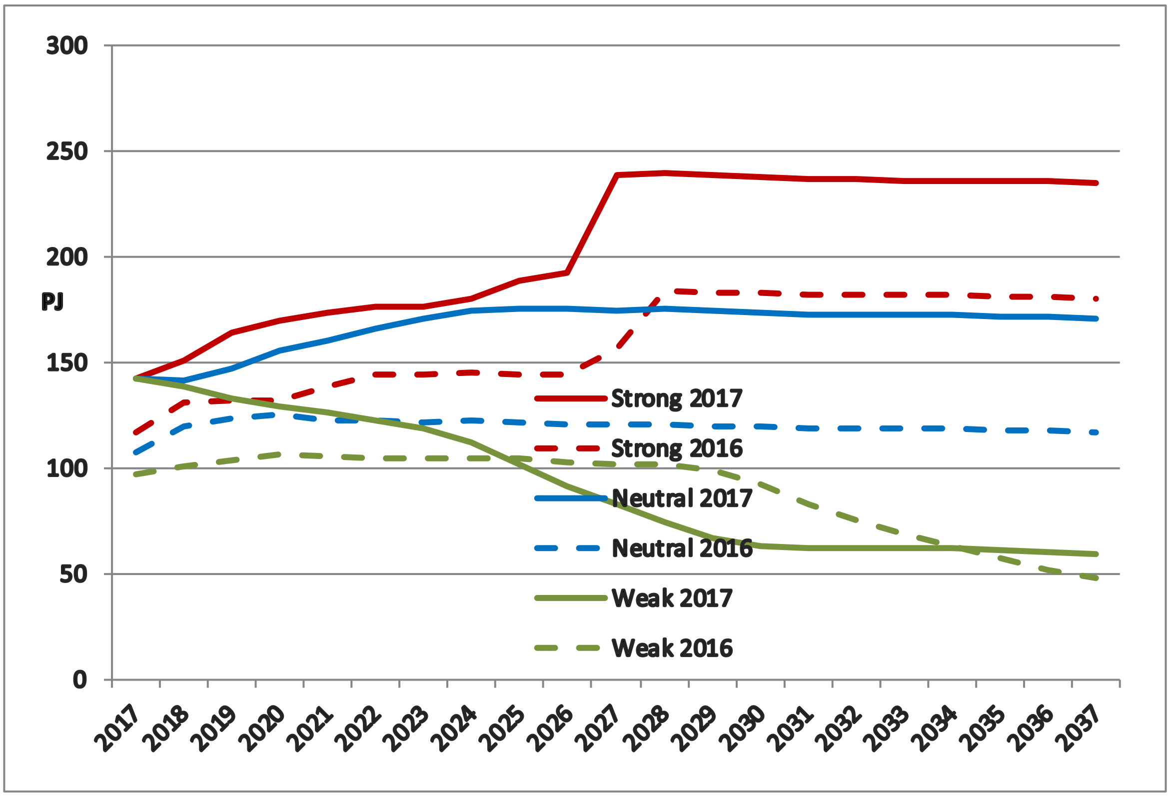


Figure 4-3 Total grid electricity usage in compression (GWh)

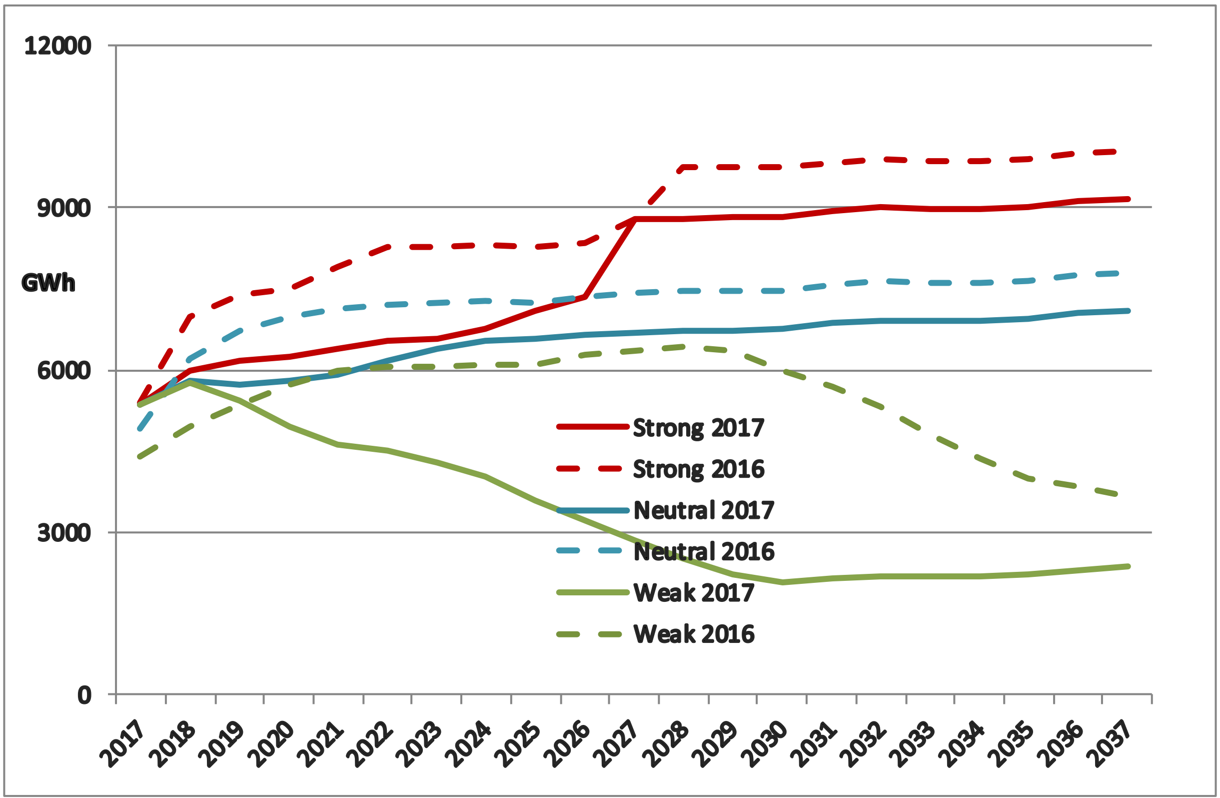


Figure 4-4 to Figure 4-5 show each projects' contribution to the Neutral Scenario projections, for LNG exports, and gas usage respectively. The decline in QCLNG exports in 2018 reflects the maintenance activities in the first half of the financial year. It is noted that AEMO has not provided LGA with each project's estimates for 2018 and 2019, hence these values are LGA estimates based on the projects' aggregate values.

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.

The decline in electricity usage up to 2021 is due to some electricity powered plants apparently being used to supply the domestic market in 2016 and 2017. This component is assumed to decline to zero over four years.

Figure 4-4 LNG export projections, Neutral Scenario

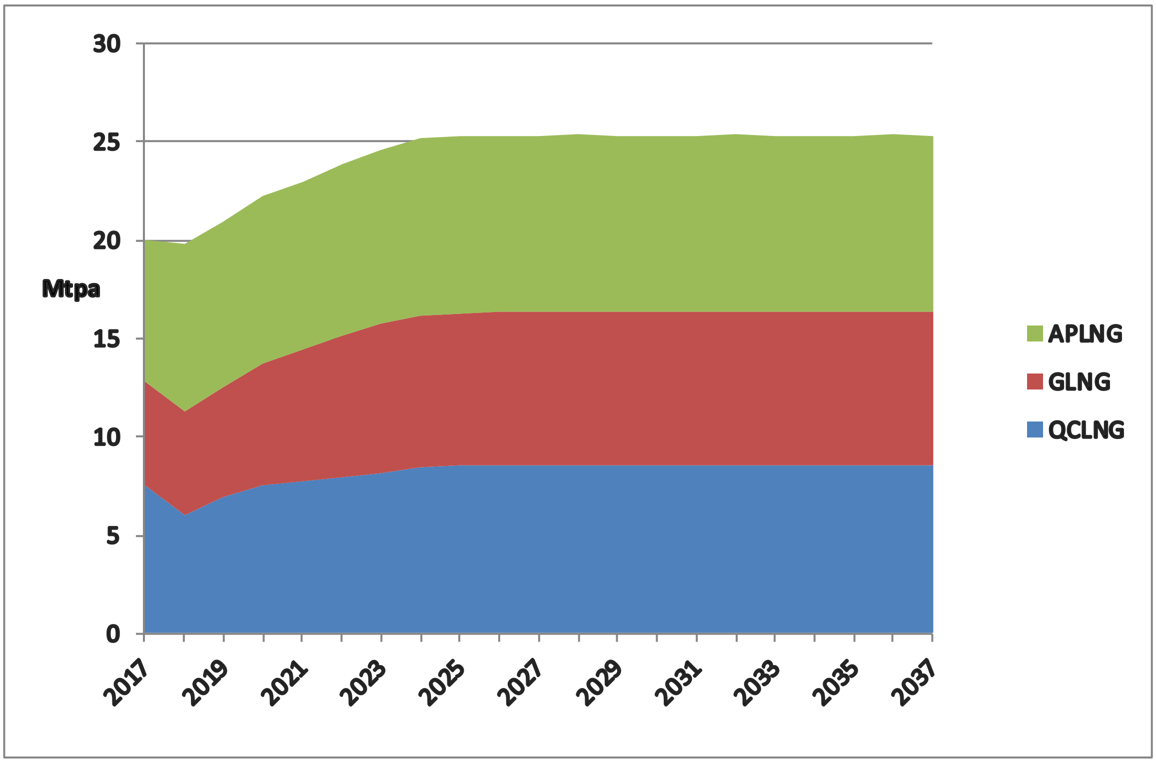
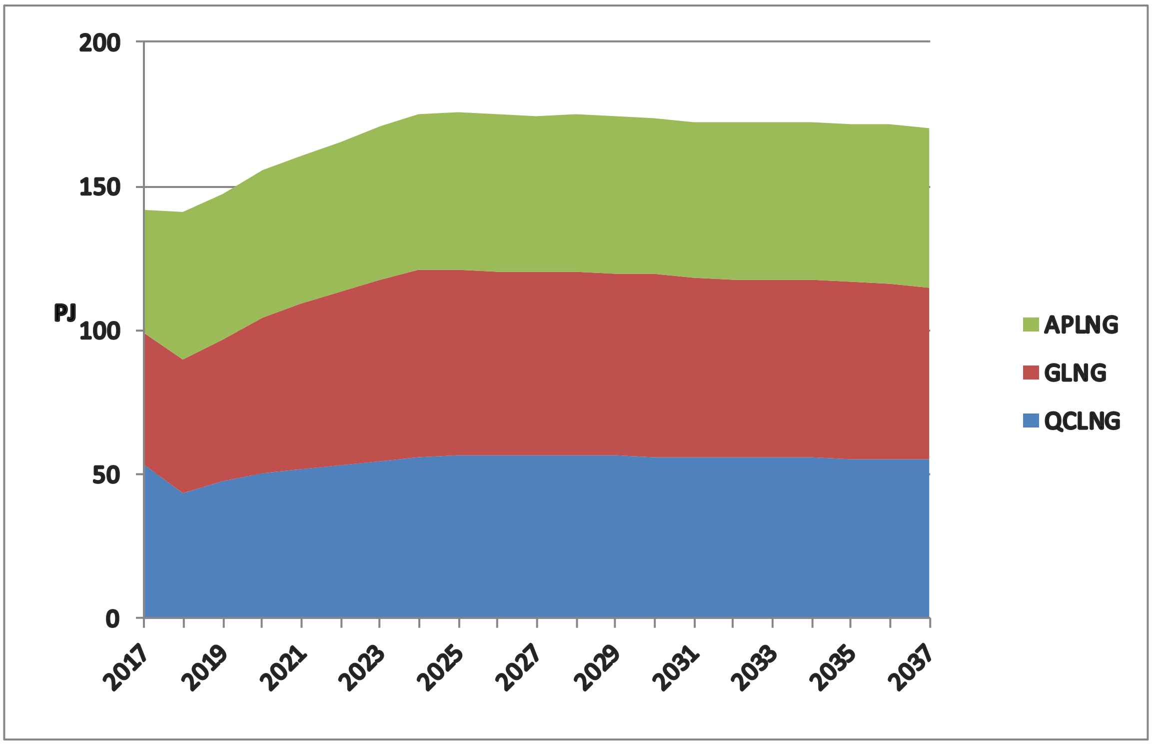


Figure 4-5 Gas used in liquefaction, transmission and production, Neutral Scenario



4.2 Peak demand projections

Figure 4-6 to Figure 4-8 show the peak winter gas and peak winter and summer grid electricity demand projections respectively. Winter/summer differentiation has been discontinued in 2017 owing to the adoption of actual gas usage rates, which do not exhibit the seasonality that was assumed in 2016.

At the individual project level, the peak projection model for 2017 is the same as in 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. Whereas in 2016 the aggregate projection was based on an estimated degree of coincidence among the projects, for 2017 this has been changed to a model relating the aggregate peak to aggregate annual usage, by means of a load factor, which recent data suggests is a more reliable model of aggregate peak demand. This is perhaps less appropriate in the Weak Scenario, where plants operate well below capacity, unless it is assumed that some plants are mothballed. LGA considers that mothballing is highly likely in this scenario.

The peak electricity model is based on the peak gas model hence the scenario patterns are as for peak gas. Neutral Scenario MD (winter and summer) is projected to be 712 MW in 2020, rising to 877 MW by 2037 owing to the assumed increase in the proportion of electrically compressed plant over time.

Figure 4-6 Peak winter gas demand

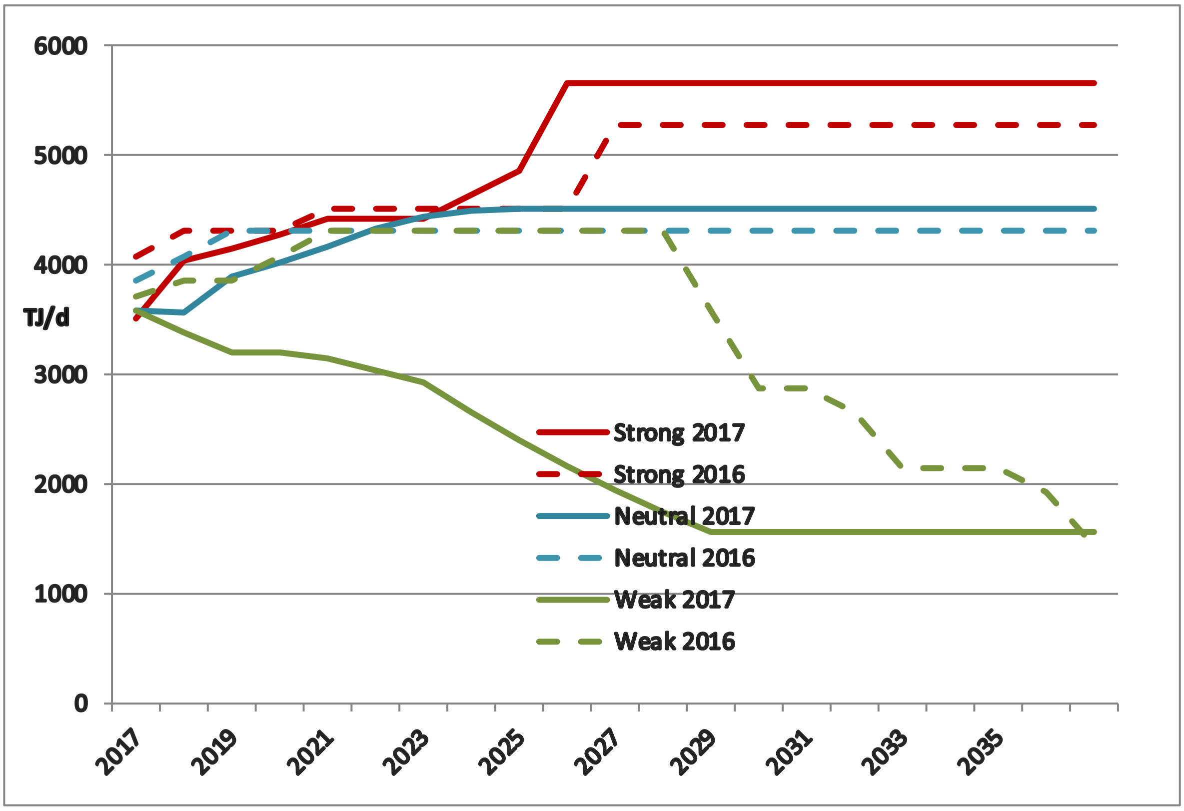


Figure 4-7 Peak winter grid electricity demand

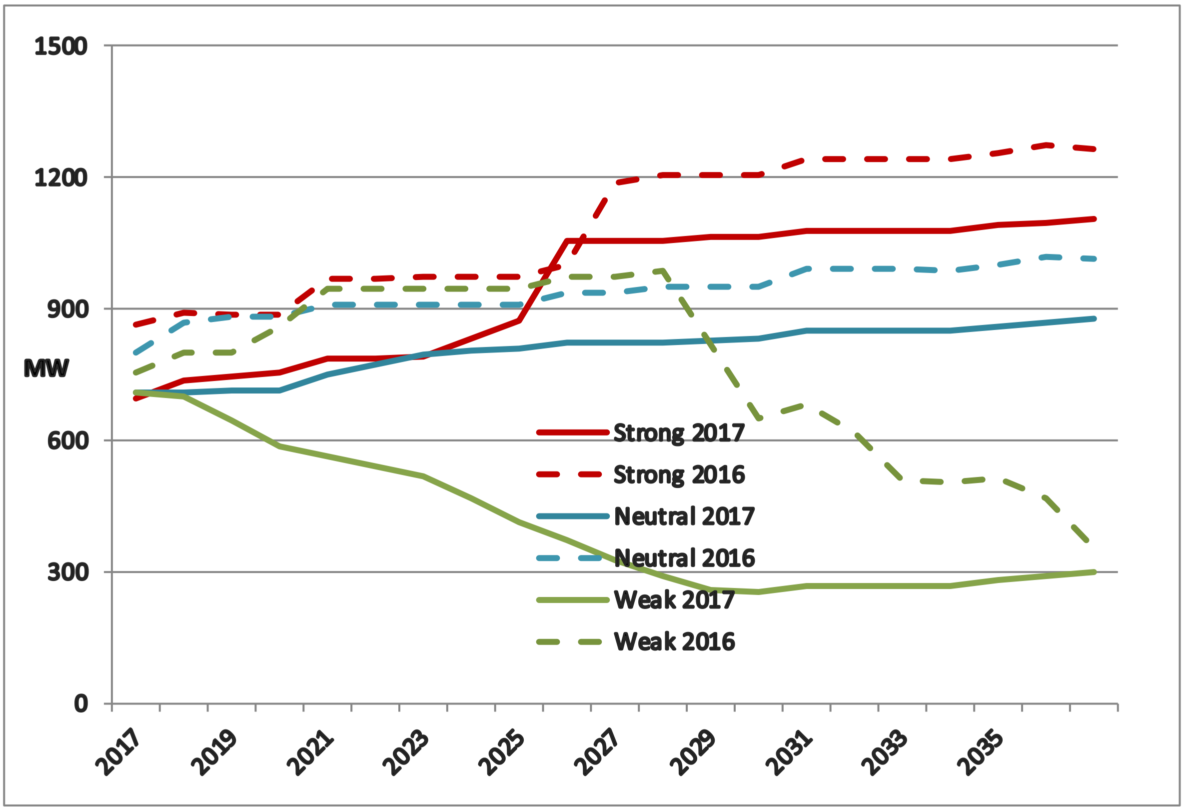
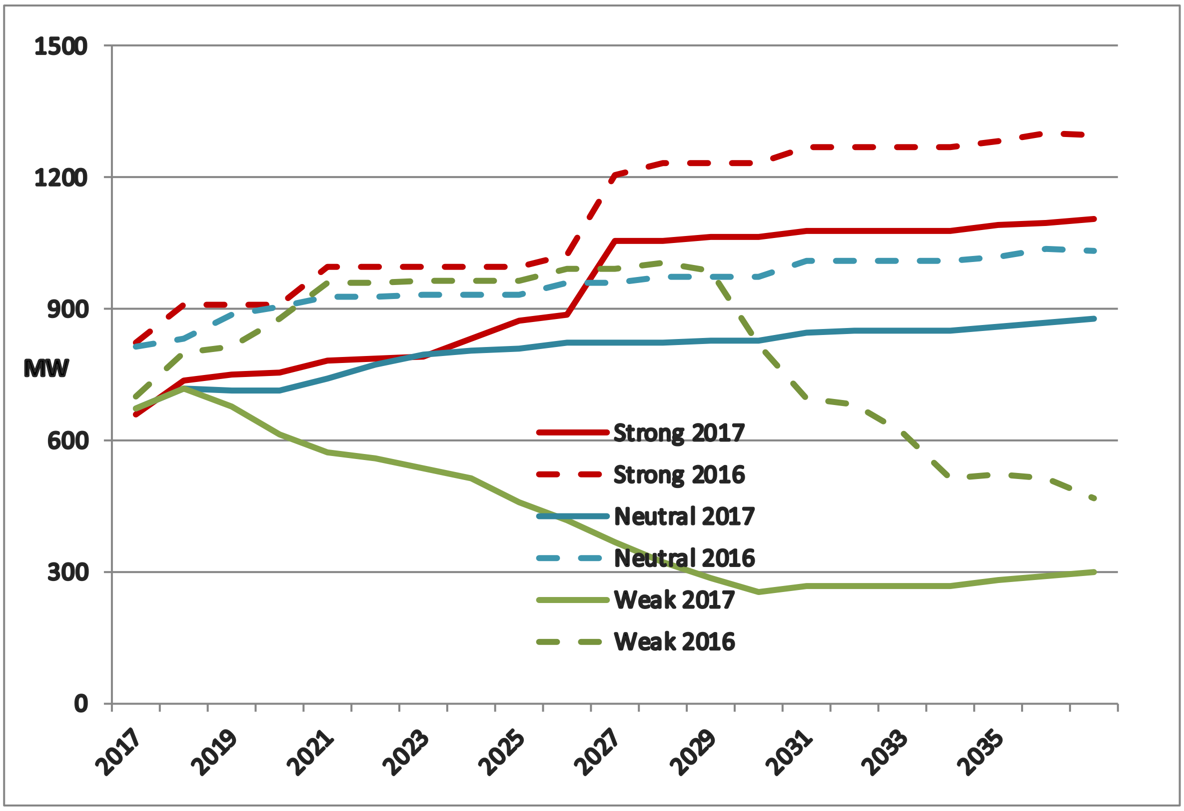


Figure 4-8 Peak summer grid electricity demand



4.3 Monthly projections

Monthly projections of LNG exports, gas usage and grid electricity usage to July 2021 are presented in Figure 4-9 to Figure 4-11. Specific points to note include:

- Values up to July 2017 are estimated actuals (in the 2017 Projections)
- Peaks and troughs in exports are mostly the result of differences in the numbers of days per month. The differences between the updated Neutral projections and the 2016 Neutral projections are largely due to slower ramp up of exports.
- For gas usage, the monthly charts no longer reflect the seasonality of liquefaction usage used in the 2016 projections (most gas is used in liquefaction). The differences between the updated projections and the 2016 NEFR projections are largely due to the higher usage rate in 2017.
- For electricity, the differences between the updated projections and the 2016 projections are largely due to slower ramp up and the revised estimates of the electricity requirements for gas compression.

Figure 4-9 Total LNG export projections (Mt/month)

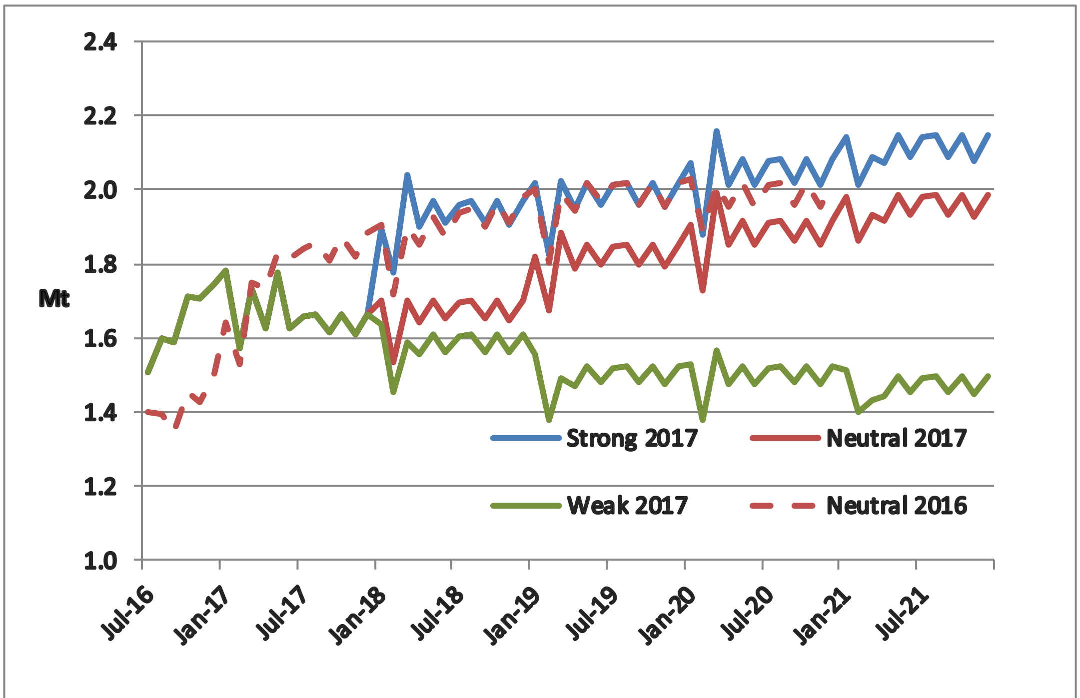


Figure 4-10 Total gas used in liquefaction, transmission and production (PJ/month)

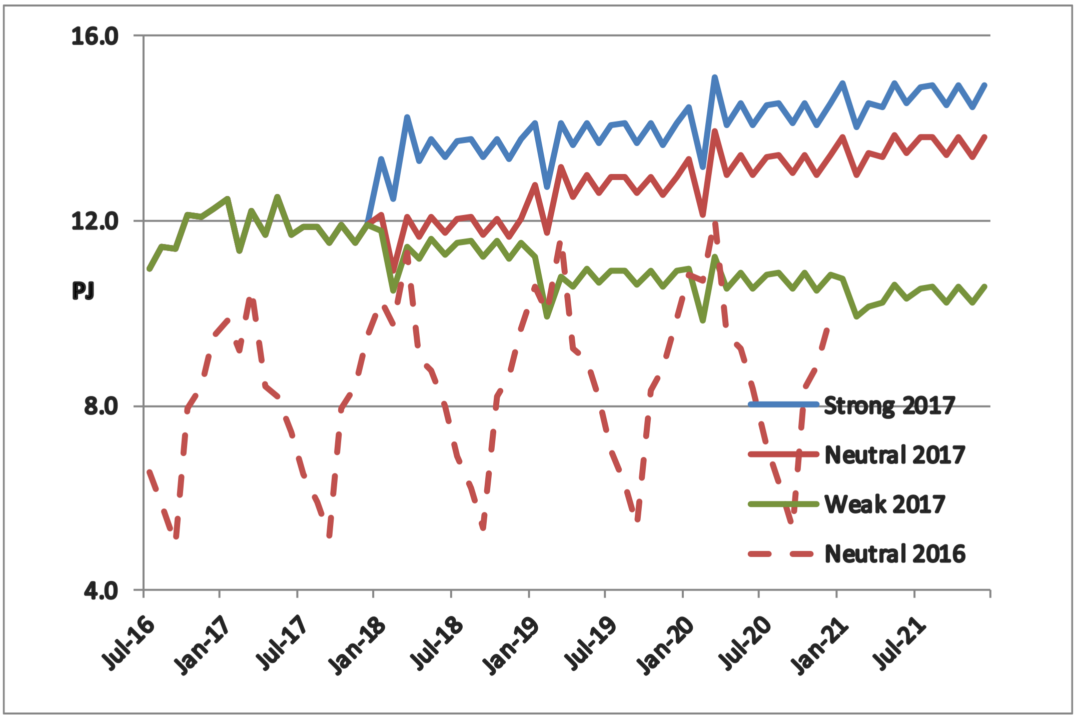
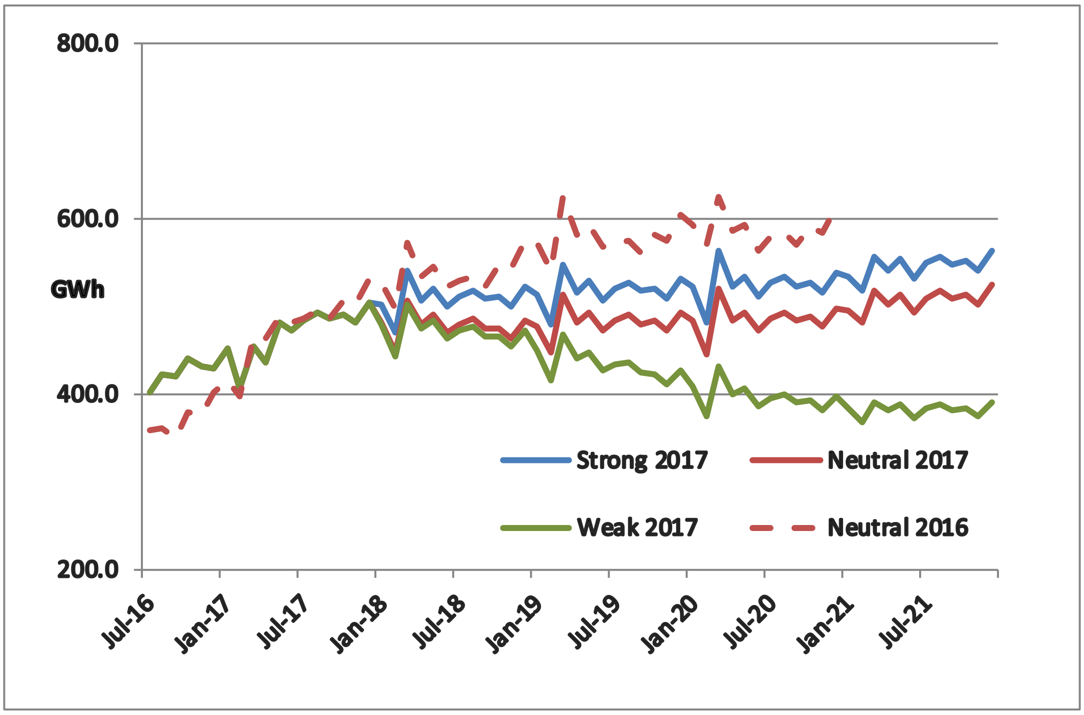


Figure 4-11 Total grid electricity usage (GWh/month)



Appendix A. RMMLNG

A.1 LNG Market Zones

The ten global LNG market zones in RMMLNG are defined as:

1. Five separate countries: China; India; Japan; South Korea; and Taiwan
2. Four regions:
   a. East Asia

      Bangladesh; Indonesia; Malaysia; Philippines; Singapore; Thailand; Vietnam

   b. Europe

      Austria; Belgium; Bulgaria; Croatia; Czech Republic; Denmark; Estonia; Finland; France; Germany; Greece; Hungary; Ireland; Italy; Latvia; Lithuania Luxembourg; Netherlands; Norway; Poland; Portugal; Romania; Serbia; Slovakia; Slovenia; Spain; Sweden; Switzerland; Turkey; UK

   c. Middle East/Africa

      Bahrain; Dubai; Kenya; Kuwait; Pakistan; South Africa

   d. South America

      Argentina; Brazil; Chile; Dominican Republic; Mexico
3. Bunker Fuel

A.2 LNG Producers and Costs

The following twenty producers are represented in RMMLNG:

Table A 1 LNG Producers and their marginal costs of gas production and liquefaction (2015 $US/mmbtu)

		Gas Production			Liquefaction			Combined		
Country	**Basin**	**Short-run**	**Long run T1**	**Long run T2**	**Short-run**	**Long run T1**	**Long run T2**	**Short run**	**Long run T1**	**Long run T2**
Algeria	**Atlantic**	$2.18	$3.50	$4.50	$1.58	$4.20	$6.00	$3.75	$7.70	$10.50
Other Africa	**Atlantic**	$2.18	$3.50	$4.50	$1.58	$6.00	$6.00	$3.75	$9.50	$10.50
Libya	**Atlantic**	$2.18	$3.50	$4.50	$1.58	$6.00	$6.00	$3.75	$9.50	$10.50
Nigeria	**Atlantic**	$2.18	$3.50	$4.50	$1.58	$4.20	$6.00	$3.75	$7.70	$10.50

		Gas Production			Liquefaction			Combined		
Country	**Basin**	**Short-run**	**Long run T1**	**Long run T2**	**Short-run**	**Long run T1**	**Long run T2**	**Short run**	**Long run T1**	**Long run T2**
Norway	**Atlantic**	\$2.18	\$3.50	\$4.50	\$1.58	\$6.00	\$6.00	\$3.75	\$9.50	\$10.50
Trinidad	**Atlantic**	\$2.25	\$4.00	\$5.00	\$1.65	\$6.00	\$6.00	\$3.90	\$10.00	\$11.00
Eastern US	**Atlantic**	\$2.10	\$3.00	\$4.00	\$1.43	\$3.85	\$5.50	\$3.53	\$6.85	\$9.50
Oman	**Middle East**	\$2.18	\$3.50	\$4.50	\$1.58	\$6.00	\$6.00	\$3.75	\$9.50	\$10.50
Qatar	**Middle East**	\$1.88	\$2.00	\$2.50	\$0.91	\$2.49	\$3.55	\$2.78	\$4.49	\$6.05
Mozambique &Tanzania	**Middle East**	\$2.03	\$3.50	\$3.50	\$1.43	\$6.00	\$6.00	\$3.45	\$9.50	\$9.50
W&N Australia	**Pacific**	\$2.21	\$3.95	\$4.74	\$1.65	\$4.38	\$6.25	\$3.86	\$8.32	\$10.99
Eastern Australia	**Pacific**	\$2.33	\$3.95	\$5.53	\$1.77	\$4.38	\$6.25	\$4.10	\$8.32	\$11.78
Brunei	**Pacific**	\$2.25	\$4.00	\$5.00	\$1.65	\$6.00	\$6.00	\$3.90	\$10.00	\$11.00
Indonesia	**Pacific**	\$2.25	\$4.00	\$5.00	\$1.65	\$4.20	\$6.00	\$3.90	\$8.20	\$11.00
Malaysia	**Pacific**	\$2.25	\$4.00	\$5.00	\$1.65	\$4.20	\$6.00	\$3.90	\$8.20	\$11.00
PNG	**Pacific**	\$2.10	\$3.00	\$4.00	\$1.50	\$6.00	\$6.00	\$3.60	\$9.00	\$10.00
Peru	**Pacific**	\$2.25	\$4.00	\$5.00	\$1.65	\$6.00	\$6.00	\$3.90	\$10.00	\$11.00
Russia (Sakhalin)	**Pacific**	\$2.40	\$6.00	\$6.00	\$1.80	\$4.20	\$6.00	\$4.20	\$10.20	\$12.00
Canada	**Pacific**	\$2.21	\$4.75	\$4.75	\$1.61	\$6.00	\$6.00	\$3.83	\$10.75	\$10.75
Russia Pipeline	**Russia**	\$2.03	\$3.50	\$3.50	\$0.00	\$0.00	\$0.00	\$2.03	\$3.50	\$3.50

Sources: Nexant, 2016 EIA Energy Conference, Washington, July 11-12, 2016; Gaffney Cline & Associates, Prospects for East African LNG, 2014; Oxford Institute for Energy Studies, The Impact of Lower Gas and Oil Prices on Global Gas and LNG Markets

A.3 LNG Shipping Costs

LNG shipping costs are represented on a basin to market basis, as below.

Table A 2 Shipping Costs ($US/mmbtu)

	From			
To	**Atlantic**	**Middle East**	**Pacific**	**Russia (Pipeline)**
Japan	$2.15	$2.00	$0.75	N/a
China	$2.05	$1.90	$0.65	$6.00
Other E Asia	$1.95	$1.80	$0.55	$6.00
India	$1.40	$0.25	$0.45	N/a
ME-Africa	$1.20	$0.15	$0.70	N/a
Sth America	$0.90	$1.70	$2.00	N/a
Europe	$1.50	$2.00	$2.60	$2.00

Sources: Nexant, 2016 EIA Energy Conference, Washington, July 11-12, 2016; Gaffney Cline & Associates, Prospects for East African LNG, 2014; Oxford Institute for Energy Studies, The Impact of Lower Gas and Oil Prices on Global Gas and LNG Markets

A.4 Gas reserves

Table A 3 Gas reserves available for LNG (PJ, End 2015)

Country	Total Reserves	Domestic & Pipeline Exports	Available for LNG
Algeria	167,851	86,754	81,097
Other Africa	11,812	4,352	7,460

Country	Total Reserves	Domestic & Pipeline Exports	Available for LNG
Libya	56,021	5,016	51,005
Nigeria	190,428	0	190,428
Norway	69,208	65,958	3,251
Trinidad	12,133	6,209	5,924
Eastern US	388,979	318,554	70,425
Oman	252,567	0	252,567
Qatar	913,841	74,328	839,513
Mozambique &Tanzania	171,052	0	171,052
W&N Australia	85,681	9,000	76,681
Eastern Australia	40,315	0	40,315
Brunei	10,234	0	10,234
Indonesia	105,817	55,290	50,527
Malaysia	43,572	30,704	12,868
PNG	21,100	0	21,100
Peru	15,403	8,550	6,853
Russia (Sakhalin)	52,750	0	52,750
Canada	95,161	70,262	24,899
Russia Pipeline	1,148,895	663,822	485,073
	3,852,816	1,398,798	2,454,018

Source: BP Statistical Review of World Energy 2016 and 2017.

A.5 Planning and Variation Scenarios

In a standard or planning scenario, RMMLNG balances demand in any year assuming that supply capacity can be constructed over the preceding four years, with perfect demand foresight, using all the capacity options. Variation scenarios are designed to test what happens when perfect foresight breaks down.

In a variation scenario, RMMLNG supply is constrained to values determined in a planning scenario for up to three years, while demand is increased or decreased relative to the planning scenario for the same period. If demand is higher, the prices rise until demand is cut back to the constrained supply level and similarly prices fall if demand is lower.

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
RMMLNG	Market Model Global LNG (LGA's Global LNG market model)
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