ACIL ALLEN CONSULTING

REPORT TO
APA GROUP

27 AUGUST 2016

ROMA TO BRISBANE PIPELINE

ASSESSMENT OF DEMAND FOR SERVICES

FOR THE ACCESS ARRANGEMENT PERIOD 1 JULY 2017 TO 30 JUNE 2022

C O N T E N T S

C O N T E N T S

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GLOSSARY OF TERMS

AA	Access Arrangement - document governing terms of third party access to pipelines
AAI	Access Arrangement Information
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APA	The APA Group
APTPPL	APT Petroleum Pipelines Limited, owner of the RBP
As Available Capacity	Pipeline capacity made available on a non-firm basis to firm capacity entitlement holders, used and paid for by the shipper only when needed and only if the service provider has capacity available at the time. Shipper must hold firm capacity rights. See and compare with "Interruptible Capacity".
CCGT	Combined Cycle Gas Turbine (electricity generation plant)
Conventional gas	Natural gas produced from hydrocarbon reservoirs in sandstone or similar formations
CSG	Coal Seam Gas; natural gas adsorbed in coal seams and released by drilling and dewatering
Firm capacity	Pipeline capacity reserved under a gas transportation contract and paid for a user
Forward haul	Transportation service in the direction of physical flow on the pipeline.
Gas	Natural gas, a mixture of gases including hydrocarbon gases (predominantly methane, typically with lesser amounts of ethane and higher hydrocarbons) and small amounts of inert gases such as nitrogen and carbon dioxide. Includes both Conventional Gas and CSG.
GJ	Gigajoule (Joule x 10^9)

GPG	Gas-fired Power Generation
GSA	Gas Supply Agreement
GTA	Gas Transportation Agreement
Interruptible Capacity	Pipeline capacity made available on a non-firm basis, used and paid for by the shipper only when needed and only if the service provider has non-firm capacity available at the time. Shipper need not hold firm capacity rights. See and compare with “As Available Capacity”.
LF	Load Factor; average daily load/peak daily load. A measure of the degree of “swing” or inter-daily variation in gas flow.
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
MAQ	Maximum Annual Quantity entitlement under a Gas Transportation Agreement
MDQ	Maximum Daily Quantity entitlement under a Gas Transportation Agreement
MHQ	Maximum Hourly Quantity entitlement under a Gas Transportation Agreement
NEM	National Electricity Market; the central market for wholesale electricity in Eastern Australia, administered by AEMO.
NGL	National Gas Law
NGR	National Gas Rules
OCGT	Open Cycle Gas Turbine (electricity generation plant)
PJ	Petajoule (Joule x 10^{15})
QGP	Queensland Gas Pipeline (Wallumbilla to Gladstone and Rockhampton) operated by Jemena
RBP	Roma to Brisbane Pipeline
Shipper	A party contracting for services on a gas transmission pipeline; also known as a User.
SRMC	Short Run Marginal Cost
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline, operated by APA
TJ	Terajoule (Joule x 10^{12})
User	A party contracting for services on a gas transmission pipeline; also known as a Shipper.
WGSH	Wallumbilla Gas Supply Hub, a voluntary trading market for sale and purchase of gas. The WGSH is operated by AEMO.
Western Haul	Transportation service (physical or contractual) on RBP in a westerly direction (that is, towards Wallumbilla).

EXECUTIVE SUMMARY

ACIL Allen has been engaged to advise APA Group in relation to future demand for gas transmission services on the Roma to Brisbane Pipeline (RBP).

The RBP is a major gas transmission pipeline linking the Wallumbilla gas supply hub to gas demand centres in the Greater Brisbane region of southeast Queensland, South Coast and Darling Downs regions of southern Queensland. Gas transported on the RBP is predominantly Coal Seam Gas (CSG) produced from fields in the Surat Basin, near Roma in southern Queensland.

There are numerous gas transmission pipelines operating in the Surat Basin CSG fields. In particular, the three LNG proponent groups have developed independent upstream (production, processing, compression and transportation) systems that do not rely on third-party services to secure the transportation path from the CSG production fields to their LNG facilities. While these LNG projects may from time to time make use of negotiated services on the RBP to provide operational flexibility, the RBP is not an integral part of any of these delivery systems.

There are seven National Electricity Market (NEM) scheduled generators located in the vicinity of the RBP. Two of these stations (Oakey, Swanbank E) rely on RBP for gas supply. The other five stations (Roma, Condamine, Darling Downs, Braemar 1, Braemar 2) are connected to other transmission pipelines. The two Braemar stations are connected to RBP; the other three stations are not connected to RBP.

A number of recent and prospective market developments will significantly affect the future demand for transport services provided by RBP. These include the temporary closure (“mothballing” or “cold storage”) of the Swanbank E power station in December 2014; the permanent closure of the BP Bulwer Island refinery and co-generation plant from July 2015; and uncertainty over the longer term outlook for the Incitec Pivot Gibson Island fertiliser plant beyond expiry of the majority of its current gas supply arrangements in late 2017.

Forecast demand for eastern haul services

ACIL Allen has developed a Base Case forecast for annual east-bound throughput and peak daily demand, and has also described Low Case and High Case variants that seek to capture the potential downside and upside demand associated with the binary uncertainties in relation to Swanbank E and Incitec Pivot Gibson Island.

Figure ES 1 summarises the Base, Low and High Case history (including AER forecast for the current AA period) and forecasts for annual gas throughput over the next access arrangement period (1 July 2017 to 30 June 2022). Annual throughput is expected to fall from a peak of about 61,800 TJ in 2013–14 (driven in part by elevated levels of gas use for power generation in the lead up to commissioning of LNG facilities in Gladstone) to about 32,800 TJ in 2016–17. This steep decline has been driven by a number of market developments: withdrawal of the Swanbank E combined-cycle gas turbine (CCGT) plant in December 2014; closure of the BP Bulwer Island refinery and co-generation facility in July

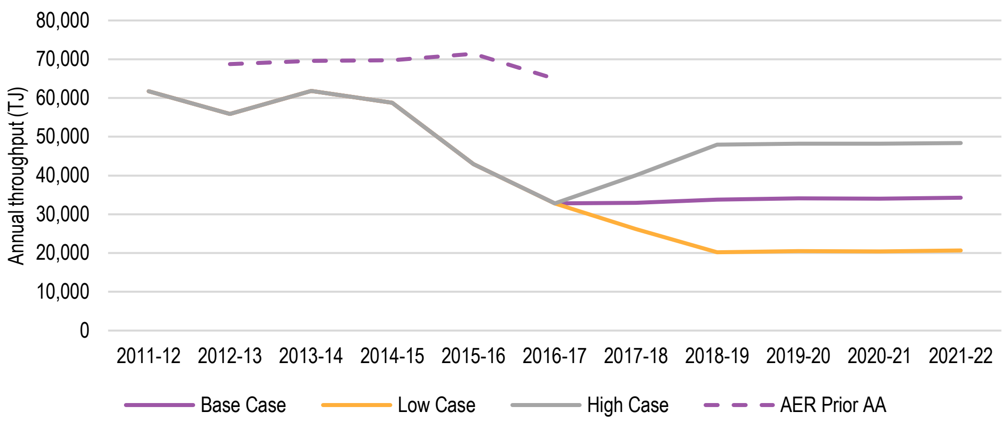
2015; and a reduction dispatch of gas-fired generation following commissioning of five LNG liquefaction trains in Gladstone over the period December 2014 to May 2016.

The Low Case shown in **Figure ES 1** reflects a scenario in which the Incitec Pivot Gibson Island plant ceases manufacturing operations after expiry of its current gas supply arrangements in late 2017, and the Braemar open cycle gas turbine plants draw less peak gas supply from the RBP.

The High Case shown in **Figure ES 1** reflects a scenario in which the Incitec Pivot Gibson Island plant continues manufacturing operations, the Swanbank E power station returns to service in late 2017, and the Braemar open cycle gas turbine plants draw more peak gas supply from the RBP.

As indicated, there is a wide range of potential outcomes for RBP that will be determined by a small number of binary decisions regarding continued operation or closure and utilisation levels of individual large loads (Swanbank E, Incitec Pivot Gibson Island, Braemar 1 & 2 power stations).

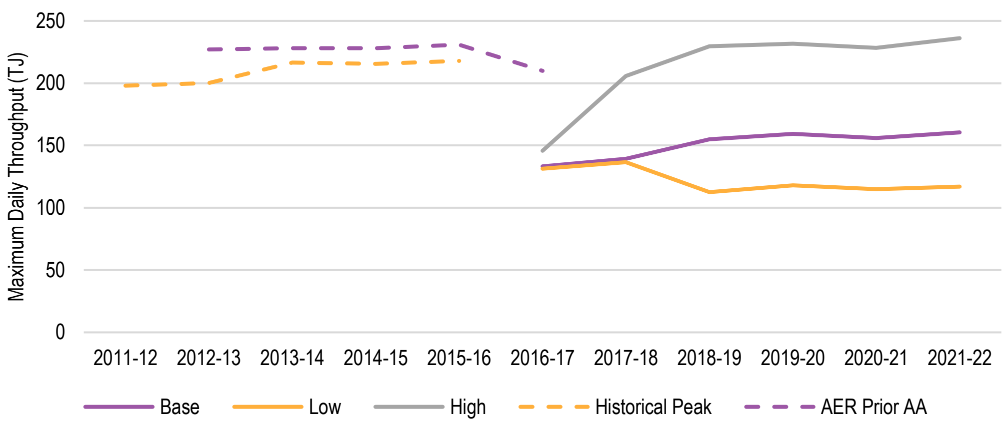
FIGURE ES 1 RBP ANNUAL THROUGHPUT: BASE, LOW AND HIGH CASES



SOURCE: ACIL ALLEN CONSULTING ANALYSIS

Figure ES 2 summarises the forecast for maximum peak day demand for east-bound services on RBP. Also plotted on **Figure ES 2** are the observed historical maximum daily throughput on RBP as recorded in the AEMO Actual Flow data and the AER forecast maximum demand for the current AA period.

FIGURE ES 2 RBP MAXIMUM DEMAND FOR EAST-BOUND SERVICES: BASE, LOW AND HIGH CASES



SOURCE: ACIL ALLEN CONSULTING ANALYSIS

The future system peak demand for east-bound services under the Base Case assumptions ranges between 139 and 161 TJ/day over the forecast period 2017–18 to 2021–22. The Low Case (early closure of Incitec Pivot Gibson Island and reduced demand from Braemar power stations) sees maximum demand ranging between 113 and 137 TJ/day while the High Case (early return to operation for Swanbank E power station and increased demand from Braemar power stations) sees maximum demand increase to between 206 and 236 TJ/day over the forecast period.

Implications for future services

Assuming no change in the physical capacity of the RBP, the forecast lower peak utilisation rates are likely to result in a shift in the service mix on the pipeline, with less demand for firm service and more demand for non-firm services. This is particularly the case for open-cycle gas turbine (OCGT) power generation users because they will see a reduced risk of non-firm (“as available” and interruptible) services being unavailable when needed. They may well will look to reduce their total cost of gas transportation by booking less firm service and relying on more non-firm service.

Similar considerations apply, but to a lesser extent, for gas retailers. Because retailers require a high level of confidence in their ability to meet customer supply obligations, they would normally be expected to cover most, if not all, of their peak supply requirement with firm capacity entitlements. However, this again depends on the risk associated with non-firm services. If there is ample spare capacity in the pipeline system and the risk of non-firm services being interrupted is very low, even on system peak days, there will be an incentive for retailers to book less firm capacity and more non-firm capacity.

The forecast lower peak utilisation rate for the RBP is therefore likely to result in a shift in the service mix on the pipeline, with less demand for firm service and more demand for non-firm services. However, it is not possible to say just how much impact this may have on future levels of firm capacity booking in the RBP, because each shipper will adopt a commercial contacting strategy that reflects their individual circumstances. Other relevant considerations will include:

— the relative levels of charges for firm and non-firm services
— the extent to which firm service entitlements are a pre-requisite for non-firm services
— the perceived risk that firm capacity in the RBP will be reduced in the future.

We have considered whether there may be strategies available to APA to encourage an early return to service of the Swanbank E power station, or to reduce the risk of losing the Incitec Pivot Gibson Island load. There may be limited opportunities (for example by offering “prudent discounts) but the commercial position of these key customers will ultimately be driven primarily by factors other than gas transportation charges.

Wallumbilla Gas Supply Hub

We have considered whether trading activities at the Wallumbilla Gas Supply Hub (WGSH) are likely to generate a demand for new or additional services on the RBP specifically to support trading activities (see Chapter 5). We have concluded that it is unlikely that the operations of the WGSH will generate demand for new or additional services on the RBP during the next access arrangement period, for the following reasons:

— The transport task associated with trading on the WGSH is highly variable and unpredictable with the quantity of gas traded through the hub varying widely from day to day. It is unlikely in our view that traders would seek firm transportation services specifically for the purposes of trading in such a volatile market.
— Some traders are likely already to hold negotiated gas transportation entitlements on RBP that offer sufficient flexibility to support trading activities, without the need to take out additional transport services specifically for the purposes of trading.
— Parties who wish to trade gas on the hub but who do not currently hold transportation services in their own right (for example, industrial Tariff D users who purchase gas on a delivered basis, through a retailer) could use the capacity trading service offered by AEMO to obtain access to transport, rather than entering into a GTA with the transmission pipeline owner. Alternatively, they might arrange with their retailer (who will already hold pipeline transport entitlements) to trade their gas entitlements on their behalf.

We nevertheless assume that there will be modest uptake of RBP Western Haul service to support trading activities at the hub.

Gladstone LNG plants

The RBP is not a primary source of transport services for the CSG LNG projects, each of the project proponents having developed its own dedicated gas gathering, processing, compression and transportation systems. However the RBP could provide a number of "supporting services" that may be called on by the LNG project operators in certain circumstances. Examples of services that the RBP could provide to the LNG projects include:

- "Western Haul" services to move gas from CSG fields in the eastern Surat Basin either to Wallumbilla or to mid-line delivery points at which the gas could be transferred into the CSG LNG delivery systems.
- Short-term east-bound transportation services to allow temporary redirection of CSG to gas-fired power generators in the event of planned or unplanned disruptions to LNG production.

Western Haul service

APA has provided Western Haul services on the RBP since mid-2015, around the same time as the major ramp-up in LNG production at Gladstone. Demand for **Western Haul services** on RBP has risen since the commencement of those services in mid-2015. However, much of this demand has been associated with transient seasonal (winter) demand in southern domestic markets and with LNG operational issues during commissioning.

While rates of western flow have been increasing, both average and peak rates of eastern flow have declined. The start-up of LNG operations at Gladstone has therefore coincided with a significant shift in the mix of transportation services being provided on RBP.

Future demand for Western Haul services to supply gas to the domestic market is likely to be irregular and seasonal: not generally a basis for long-term firm transportation contracts but more likely for short-term arrangements.

We have identified total demand for RBP Western Haul Services of up to:

- 32 TJ/day of firm service
- 16 TJ/day (probability weighted) of non-firm service.

Given the pipeline transport alternatives available to the majority of market participants, we see a significant risk that these levels of usage will not eventuate. We would regard any higher level of assumed uptake of RBP Western Haul service over the next access arrangement period as being highly speculative.

1 INTRODUCTION

The APA Group ("APA") is due to lodge its proposed access arrangement and access arrangement information for the Roma–Brisbane Pipeline (RBP) for the period 1 July 2017 to 30 June 2022 with the Australian Energy Regulator (AER) in August 2016. A key component of the access arrangement information will be a forecast of demand for Reference Services on the pipeline.

APA engaged ACIL Allen Consulting Pty Ltd ("ACIL Allen") to prepare an independent assessment of the future demand for services on the RBP. That assessment is set out in this report.

1.1 Key issues

The quantum and nature of services provided by the RBP has changed significantly in recent times. Throughput under firm eastern haul transport arrangements has declined as a result of the closure of major gas-using facilities in southeast Queensland. The emergence of a large-scale LNG export industry in Gladstone based on production of coal seam gas (CSG) in central and southern Queensland has had an impact on services provided by the RBP during the construction and commissioning stages of the LNG projects, and may lead to demand for new services (for example, to enable flexible re-direction of CSG from fields in the vicinity of the pipeline) once the LNG projects are fully commissioned.

The establishment of the Wallumbilla Gas Supply Hub, which provides a voluntary trading platform allowing wholesale trading of gas in the RBP, Queensland Gas Pipeline (QGP) and South West Queensland Gas Pipeline (SWQP), has also created new service opportunities for the RBP. To facilitate trading through the Wallumbilla hub, APA has undertaken capital works to enable bi-directional operation of the RBP. However physical transfer of gas from RBP into QGP or SWQP is requires compression to enable transfer of gas from RBP into the higher pressure pipeline systems.

In the context of this rapidly-changing gas market, the task of identifying and quantifying the services that users are likely to seek on the RBP during the forthcoming access arrangement period is not straightforward. The assessment needs to address a number of discrete but inter-related questions, including:

— What will be the annual and maximum daily gas demand in southeast Queensland served by the RBP during the forthcoming access arrangement period?

— How much of the above demand will be met through firm haulage transport arrangements?

— To what extent will shippers be willing to rely on short term, non-firm transportation services, bearing in mind the lower expected utilisation of the available capacity in the RBP?

— What impact will the emerging LNG industry in Gladstone have in terms of the services sought on the RBP?

— What impact will the Wallumbilla Gas Supply Hub have in terms of the services sought on the RBP?

— How much west-bound transport service on RBP will be sought and what will be the nature of that service requirement?

This report seeks to address these issues in a systematic way.

1.2 Data sources

The analysis in this report draws on a range of data sources including:

— historical data on gas production and transportation, including throughput on the RBP, published by the Australian Energy Market Operator (AEMO) on the Natural Gas Service Bulletin Board (public data)

— historical data on gas volumes and prices traded through the Short Term Trading Markets and the Wallumbilla Gas Supply Hub, published by AEMO (public data)

— historical data on electricity plant dispatch and wholesale electricity prices, published by AEMO (public data)

— historical data on gas injections and withdrawals at specific metering points on the RBP during the current access arrangement period, supplied by APA (confidential data)

— gas demand forecasts published by AEMO in its National Gas Forecasting Report

— forecast data and assumptions drawn from ACIL Allen's modelling of eastern Australian electricity and gas markets

— other internal sources available to ACIL Allen.

2

MARKET CONTEXT

This chapter provides a brief overview of the eastern Australian gas market. It is intended to provide context to the operations of the Roma to Brisbane Pipeline (RBP).

2.1 The Eastern Australian Gas Market

Figure 2.1 provides a diagrammatic representation of the eastern Australian gas market, showing the main supply sources (conventional and coal seam gas), demand centres and transmission pipelines, together with the net flow directions on those pipelines.

Whereas the gas market in eastern Australia previously comprised a number of physically separate “point-to-point” gas supply systems (single supply source to single demand centre), the market is now physically connected across an area from Mount Isa in the north to Hobart in the south, and from Gladstone and Brisbane in the east to Adelaide and Whyalla in the west.

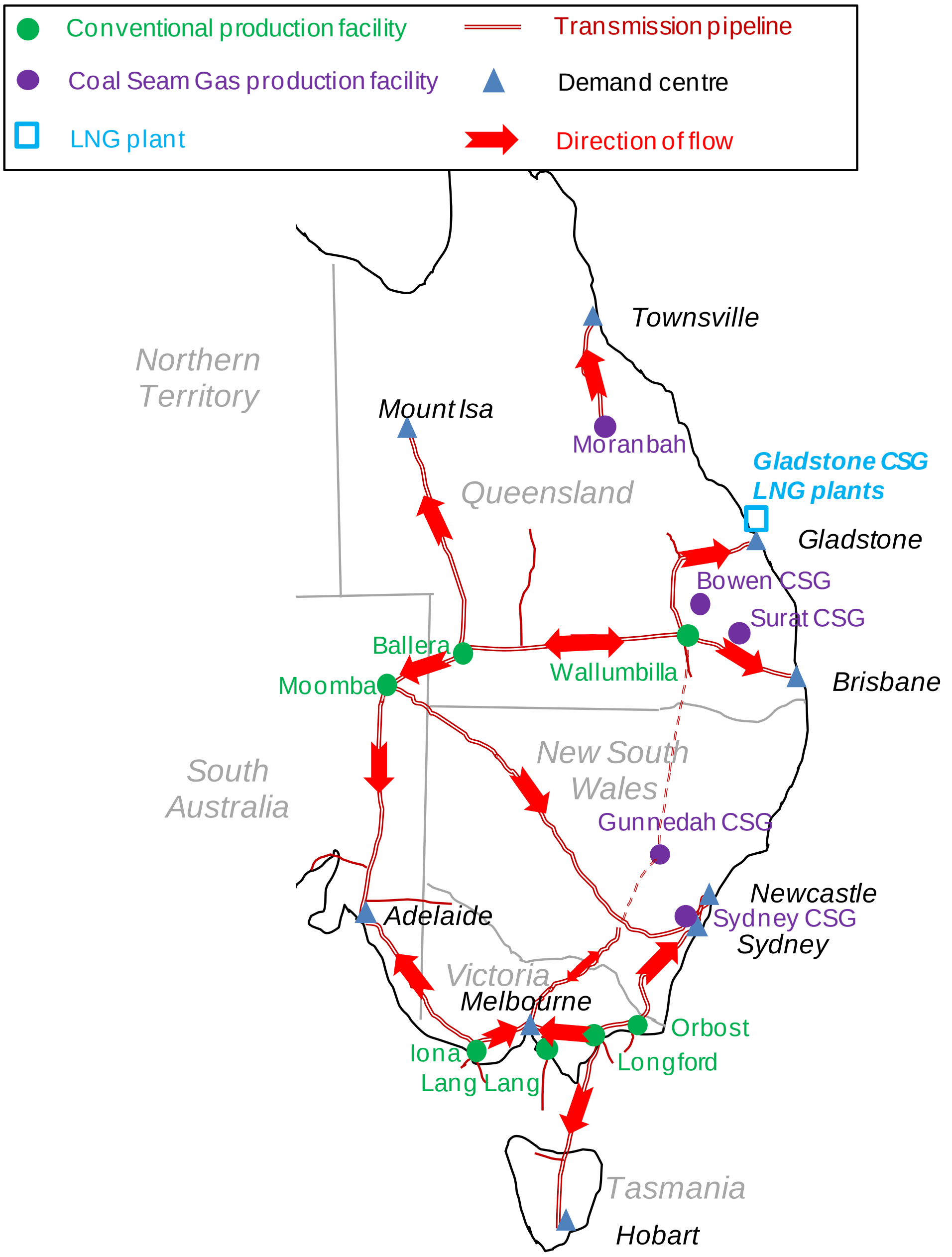
There are a number of indicators that the gas supply system illustrated in **Figure 2.1** now behaves more like a single integrated market than has been the case in the past: interconnection of the transmission pipeline system; increased levels of interstate gas trade; an increased role for aggregators; correlated price trends in regional short-term trading markets and limited emergence of swap arrangements. However the market continues to operate as a number of regional (intrastate) and state-level sub-markets between which there are developing but as-yet imperfect linkages. This is consistent with the fact that the Short Term Trading Markets which have been established in Sydney, Adelaide and Brisbane are city gate or “hub-based” markets. There are now six formal gas trading markets in operation in eastern Australia (Victoria, Sydney, Adelaide, Brisbane and most recently the Wallumbilla and Moomba gas supply hubs). Comparison of spot market pricing data demonstrates a level of correlation in price trends that strongly suggests an increasing level of regional inter-dependence. However, despite the emergence of these short-term trading platforms, the eastern Australian gas market continues to be heavily reliant on long-term bilateral contracts as the basis for gas supply and transportation.

The RBP provides the transportation path shown between Wallumbilla and Brisbane on **Figure 2.1**. It is one of the major gas transmission assets located in the vicinity of the Surat Basin and Bowen Basin coal seam gas (CSG) fields which have undergone rapid development over the past ten years, principally to support liquefied natural gas (LNG) export operations at Gladstone. However, as will be discussed in section 2.3, there are numerous other gas transmission pipelines operating in the vicinity of these CSG fields. The three LNG proponent groups have developed independent upstream (production, processing, compression and transportation) systems that do not rely on third-party services to secure the transportation paths from the CSG production fields to their LNG facilities. The RBP is not an integral part of any of these delivery systems.

The eastern Australian gas market is currently in the midst of a remarkable transition, from a relatively small, domestically-focussed system that had experience slow, incremental growth over many years, to a much larger, export-focussed system with three large LNG facilities at Gladstone set to consume the majority of the gas produced in the region.

Domestic gas consumption has contracted in recent years, and is expected to fall further. However, the overall level of gas production in eastern Australia will rise strongly as a result of the Gladstone LNG plants.

FIGURE 2.1 THE EASTERN AUSTRALIAN GAS MARKET



SOURCE: ACIL ALLEN CONSULTING

2.1.1 Current patterns of gas consumption

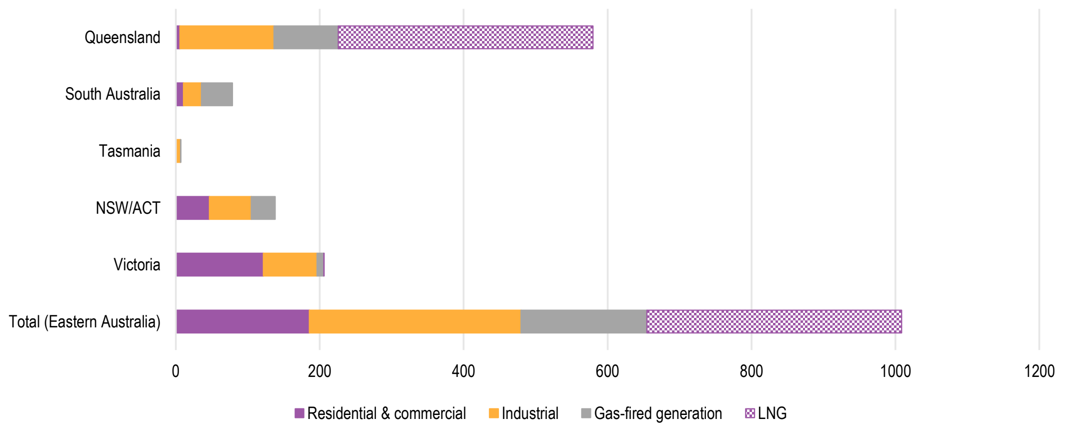
In 2015, the total amount of gas consumed in eastern Australia, excluding gas used for production of LNG, was around 655 PJ (**Table 2.1**, **Figure 2.2**). This was down about 30 PJ from the corresponding figure for 2014. Levels of domestic gas consumption have contracted over the past five years from a peak level of around 730 PJ/a. The contraction has been associated principally with the closure of a number of large gas consuming industrial facilities and, more recently, with reduced use of gas for electricity generation as a result of increasing gas costs and falling electricity demand. Gas use in 2015 for LNG production was 354 PJ, taking total eastern Australian consumption to 1,009 PJ.

TABLE 2.1 EASTERN AUSTRALIAN GAS CONSUMPTION, BY STATE AND SECTOR (CALENDAR YEAR 2015)

	Total (Eastern Australia)	Victoria	NSW/ACT	Tasmania	South Australia	Queensland
Residential & commercial	185.5	121.5	46.8	0.7	10.8	5.7
Industrial	294.3	74.9	58.2	5.8	24.7	130.7
Gas-fired generation	175.0	9.4	32.9	0.1	43.2	89.4
LNG	353.8	0.1	0	0	0	353.8
TOTAL	**1,008.6**	**205.9**	**137.8**	**6.6**	**78.6**	**579.6**

SOURCE: AEMO NATIONAL GAS FORECASTING REPORT 2015 VERSION 2 (MARCH 2016)

FIGURE 2.2 EASTERN AUSTRALIA GAS CONSUMPTION — 2015



SOURCE: AEMO NATIONAL GAS FORECASTING REPORT 2015 VERSION 2 (MARCH 2016)

In 2015, Queensland was the largest regional market with domestic consumption of 226 PJ/a. Unlike Victoria, where final end-user demand is dominated by small customers with low individual consumption (residential, commercial, and small industrial) the Queensland market is dominated by large industrial and power generation customers—both sectors that have grown rapidly in recent years. 2015 also saw the commissioning of three additional LNG production trains in Queensland (taking the total to four trains, with a combined production capacity of about 17 million tonnes of LNG per year). This sector will continue grow very rapidly over the next few years with gas demand for LNG production expected to triple total gas demand in eastern Australia.

In Victoria, gas consumption in 2015 totalled almost 206 PJ. Victoria has by far the largest proportion of residential and commercial gas consumption in its customer mix, a reflection of both the large number of gas connected customers and of the relatively high level of use per connection. This higher usage level is a result of the widespread use of gas in Victoria for space heating as well as hot water service and cooking.

Total gas consumption in New South Wales (including ACT) currently stands at around 138 PJ/a, with a customer profile more like Victoria than Queensland.

In South Australia gas consumption has decreased over the past decade from around 110 PJ/a to 79 PJ/a in 2015, with industrial plant closures and increased electricity imports having seen significant erosion of annual gas demand. However, peak demand requirements (and hence pipeline capacity demand) have remained fairly consistent with pronounced summer electricity demand peaks.

The Tasmanian market is a relatively recent development, with natural gas having only become available following the commissioning of the Tasmania Gas Pipeline (Longford to Bell Bay, Hobart and Port Latta) in 2002. Consumption in calendar 2015 was less than 7 PJ (well down from a peak level of about 18 PJ/a) following closure of the Tamar Valley CCGT power station[1]. Gas continues to be used principally for electricity generation and heavy industry.

2.1.2 Gas consumption

Over the past decade, it was widely expected that there would be strong growth in demand for natural gas in the eastern Australian domestic market, particularly as a result of increased gas use in electricity generation. However it has now become clear that domestic gas use in eastern Australia is contracting, not growing. Whereas five years or so ago most forecasters anticipated gas demand increasing to at least 1,200 PJ/a by 2030, demand forecasts now are much less bullish. AEMO now expects that eastern Australian gas demand will contract from recent levels of around 700 to around 500 PJ/a by 2018, followed by a slow recovery to about 700 PJ/a by 2035.

The much weaker outlook for domestic gas demand in eastern Australia is driven by developments on both the supply side and the demand side.

In terms of supply, the expectation of abundant, competitively priced CSG from Queensland and New South Wales has evaporated in the face of demand from the export LNG projects, high CSG production costs, low oil & LNG prices, and (particularly in New South Wales) public concern over the potential impacts of CSG exploration and production on rural activities and communities. The LNG export projects are facing higher-than-anticipated marginal costs of production for CSG within their controlled resource areas and are turning to third-party supply sources to bolster their feedstock inventories. Some recent gas supply contracts have reportedly been settled with prices linked to oil and at much higher levels than have prevailed in the past. Queensland CSG now appears very unlikely to provide an abundant, low cost source of gas for local industry.

With these price signals apparent in the market and the CSG LNG projects looking to acquire more third party gas, pricing expectations in the eastern Australian market have risen strongly despite the recent decline in oil prices.

2.1.3 Gas production

The eastern Australian gas market currently draws its supply from three main regional sources, supplemented by small amounts of production from other areas:

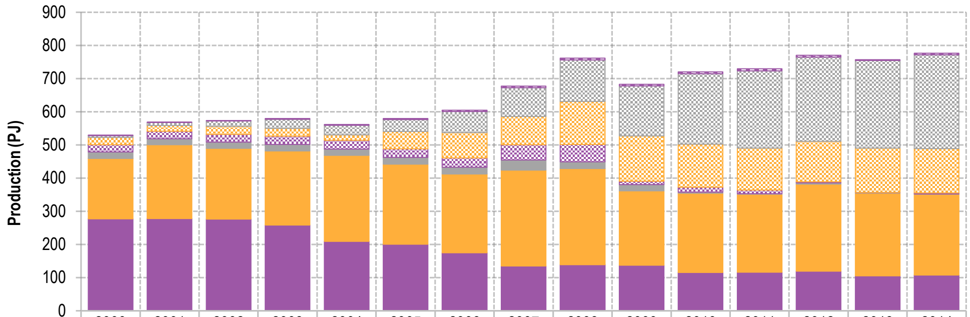
— the Bass Strait region in southern Australia (Gippsland, Otway and Bass Basins)
— the Cooper Basin in central Australia
— CSG fields in the Surat and Bowen Basins of eastern Queensland.

In New South Wales, CSG contributes modest quantities of supply (currently around 6 PJ/a). There is geological potential for NSW CSG production to grow significantly, but public opposition to the industry means that there is little prospect of a meaningful NSW CSG industry being established at least in the short to medium term.

Figure 2.3 shows levels of gas production in eastern Australia, by geological basin, since the year 2000.There have been a number of significant changes in the patterns of production over this period.

[1] Tamar Valley CCGT was recommissioned in early 2016 as a result of a prolonged outage of the BassLink interconnector with Victoria, combined with the effects of deep drought which limited Tasmanian hydro-electric capacity. Tamar Valley CCGT is expected to be mothballed once BassLink resumes normal operation.

FIGURE 2.3 EASTERN AUSTRALIA GAS PRODUCTION BY GEOLOGICAL BASIN



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
NSW CSG	1	1	1	2	2	3	4.5	5.1	5.5	4.8	5.9	5.8	5.9	2.9	4.6
Qld CSG	5.6	9.5	16.2	27.4	29.5	36.4	63.2	86.2	125.1	150.9	212.0	233.5	254.3	264.2	282.5
Otway/Bass	21.7	17.4	24.4	23.8	16.2	52.2	76.0	85.3	129.5	136.7	129.9	126.7	121.2	133.3	134.3
Bowen/Surat	22.5	22.5	23.1	24.9	26.7	25.7	28.2	46.4	52.7	9.7	14.8	10.7	3.2	1.1	2.4
Amadeus	19.0	18.1	18.8	19.4	18.4	20.5	20.4	30.1	19.7	18.7	3.1	1.8	4.2	0.6	1.0
Gippsland	182.3	222.6	213.5	223.7	259.9	241.8	238.2	289.6	290.3	224.3	239.5	235.5	262.4	250.2	243.6
Cooper/Eromanga	277.5	278.2	276.7	258.5	209.3	200.6	174.7	135.0	139.0	137.9	115.4	116.1	119.7	105.3	108.2

Note: Calendar 2014 data represents latest available as at 24 June 2016.

SOURCE: ACIL ALLEN INTERPRETATION OF APPEA PRODUCTION STATISTICS; QUEENSLAND CSG PRODUCTION FROM DNRM (GEOLOGICAL SURVEY OF QUEENSLAND)

Total conventional (non-CSG) gas production fell from 523 PJ in 2000 to 490 PJ in 2014. Production from the Cooper Basin in central Australia declined sharply, falling from 278 PJ/a in 2000 to 108 PJ in 2014. Production of conventional gas from the Surat and Bowen Basins in eastern Queensland also fell, although from much lower starting levels. These declines have been offset by an increase of more than 40 per cent in production from the Gippsland Basin, a five-fold increase in production from the Otway Basin (with the commencement of a number of offshore projects) and the start-up of production in the offshore Bass Basin.

The most dramatic change over this period was the rapid rise in Queensland CSG production, from less than 10 PJ/a in 2000 to more than 280 PJ/a in 2014 (and now running at an annualised rate of around 1,000 PJ/a – see section 2.1.1).

Future Production

With the rapid expansion of Queensland CSG production to supply very large volumes of gas to the Gladstone LNG plants and the commitment of much of the remaining reserves in the Cooper Basin to LNG exports, there will be considerable pressure on other sources of gas to supply the domestic market. In particular, increased production from the Bass Strait region will be needed to offset the declining availability of Queensland CSG and Cooper Basin conventional gas for domestic customers. New South Wales gas customers, in particular, are looking to alternative supply sources as its core gas supply from the Cooper Basin will largely dry up by 2018. A number of new gas supply deals with the Gippsland Basin producers for delivery of gas into New South Wales, and corresponding deals with APA Group and Jemena for expansion of transmission pipeline capacity between Victoria and New South Wales will support the increased production contribution that will come from the Gippsland Basin over the next few years. A key challenge will be to maintain increased levels of production as currently-developed fields begin to deplete. Higher wholesale gas prices and strong market demand should provide clear incentives for ongoing exploration and development, and the Gippsland, Bass and offshore Otway Basins offer significant potential for further discoveries. However, the recent collapse of oil prices has caused a short-term cutback in exploration activity and highlights the supply-side risk currently faced by the eastern Australian gas market.

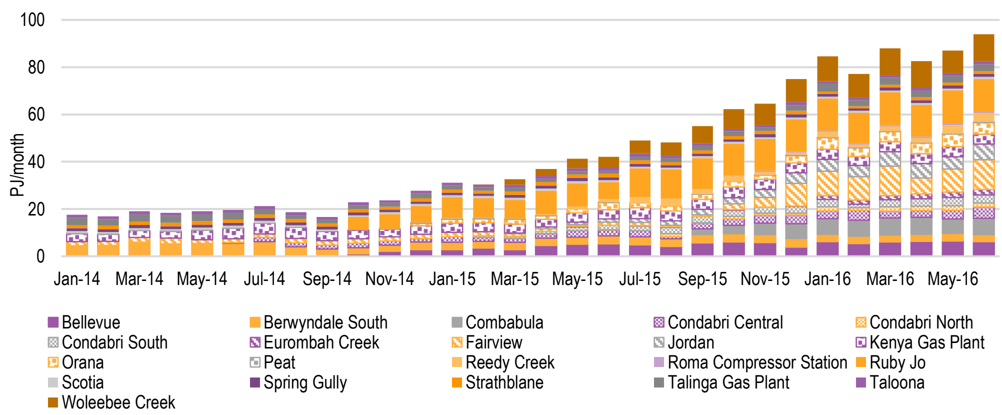
CSG production ramp up

An important factor in considering gas market responses in the transition to LNG exports is the production characteristics of coal seam gas (CSG), which provides most of the feedstock for the LNG plants. Because CSG production wells typically require an extended period of dewatering during which gas production builds up slowly as water production decreases, it was widely expected that prior to LNG start-up there would be excess gas available to the market that would suppress prices (so called "ramp-up gas"). There was also a perceived risk that the market would swing from an over-supply situation during the ramp-up period to an under-supply position following LNG plant commissioning.

In practice, the ramp-up gas issue did not affect the market as strongly as many had expected, largely because a number of mitigation strategies were employed. These included placement of ramp-up gas into underground gas storage; turn-down of some CSG wells after establishing production; use of "excess" CSG in power generation; and substitution of CSG for conventional gas within the diversified supply portfolios of some gas producers. Now that five of the six LNG trains at Gladstone have been commissioned, attention has turned to the question of whether or not the ramp up of CSG production will keep pace with the rapid increase in demand, and if not what impact this will have on eastern Australian domestic gas supply.

Data published by the Australian Energy Market Operator on the Natural Gas Services Bulletin Board (**Figure 2.4**) shows that Queensland CSG production built up strongly as the LNG plants were commissioned from late 2014 through to mid-2016.

FIGURE 2.4 RAMP UP OF QUEENSLAND CSG PRODUCTION



SOURCE: ACIL ALLEN COMPILATION OF NATURAL GAS SERVICES BULLETIN BOARD DATA

By September 2015 production had reached an annualised rate of around 660 PJ/a, at which level Queensland CSG for the first time accounted for production equivalent to the entire domestic gas demand of eastern Australia. By the end June 2016 total production of CSG in Queensland had risen to 94 PJ/month—an annualised rate of more than 1,100 PJ/a. The raw feed gas requirements for the six Gladstone LNG trains at full production will be about 1,500 PJ/a. Production levels therefore appear to be well on track, despite the adverse oil price environment in which start-up has occurred. By the end of June 2016 there were 21 CSG production and processing facilities contributing to the supply mix.

2.2 The Roma – Brisbane Pipeline

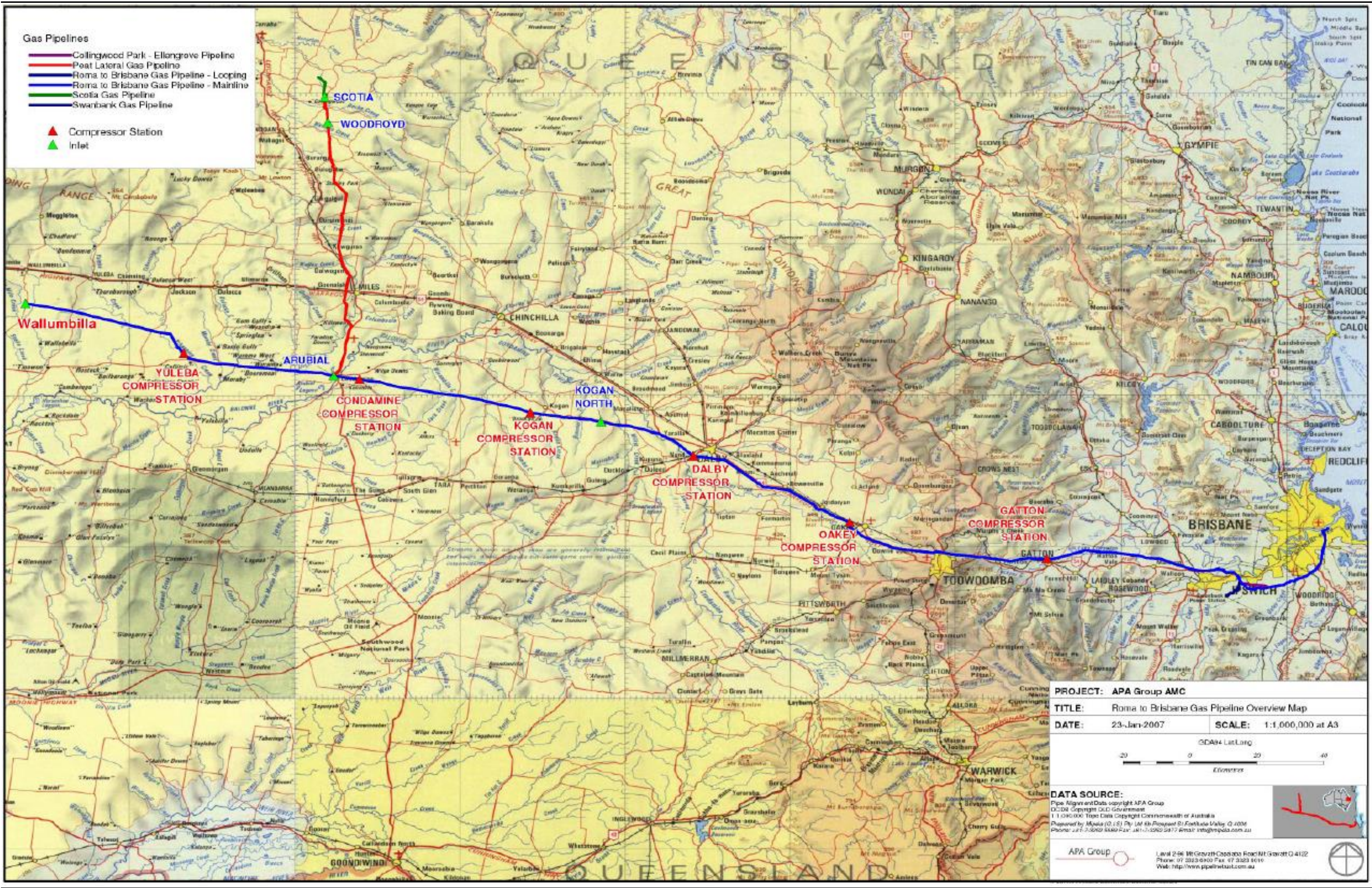
The APA Group (APA) owns the Roma to Brisbane Pipeline (RBP), a pipeline system that transports natural gas from Wallumbilla to gas users in the Brisbane metropolitan area, Toowoomba and the Gold Coast. The RBP also services mid-line loads in the Dalby region (town reticulation plus Braemer power stations), at Oakey west of Toowoomba (Oakey power station) and in the Ipswich/Swanbank region west of Brisbane (in particular the Swanbank E power station, currently closed).

The RBP consists of two parallel pipelines and a number of laterals and looping pipelines that have been added to increase the capacity of the original system. The following summary of the main asset components has been drawn from the APT Petroleum Pipelines Limited "Asset Management Plan" covering the period 12 April 2012 – 30 June 2017:

1. **Roma – Brisbane Mainline (PL 2):** Starts at the Wallumbilla Meter Station, ends at Bellbird Park Meter Station. Length 400 km. Commissioned 1969. Diameter DN250 (10 inch).
2. **Roma – Brisbane Looping (PL 2):** Starts at the Wallumbilla Meter Station, ends at Ellengrove Meter Station. Length 400 km. Commissioned 1988 – 2003. Diameter DN400 (16 inch).
3. **Peat Lateral (PL 74):** Starts at the Scotia Meter Station, ends at Condamine Main Line Valve (RBP). Length 111 km. Commissioned 2000. Diameter DN250 (10 inch). A 10.7 km extension of the Peat Lateral known as the Scotia Extension connects the Scotia Coal Seam Gas Field to the Woodroyd Treatment Plant.
4. **Metropolitan Mainline (PL 2):** Starts at Bellbird Park Meter Station, ends at SEA Main Line Valve. Length 40 km. Commissioned 1969. Diameter DN300 (12 inch).
5. **Gibson Island Lateral (PL 2):** Starts at the SEA Main Line Valve, ends at Gibson Island Meter Station. Length 2 km. Commissioned 1969. Diameter DN200 (8 inch).
6. **Swanbank Lateral (PL 2):** Starts at the Redbank Station (RBP), ends at Swanbank Meter Station. Length 5 km. Commissioned 2001. Diameter DN400 (16 inch).
7. **Lytton Lateral (PL 2):** Starts at the SEA Main Line Valve, ends at Caltex Meter Station. Length 5.4 km. Commissioned 2010. Diameter DN200 (8 inch).

A location map showing the major features of the RBP is provided in **Figure 2.5**.

FIGURE 2.5 ROMA – BRISBANE PIPELINE LOCATION MAP



SOURCE: APT PETROLEUM PIPELINES LIMITED. ASSET MANAGEMENT PLAN COVERING THE PERIOD 12 APRIL 2012 – 30 JUNE 2017"

2.2.1 Capacity of the RBP

The current capacity of the RBP as reported by the Natural Gas Services Bulletin Board is 216 TJ/day.

The system previously had a higher nominal physical capacity of 232 TJ/day; the reduced capacity is a consequence of temporary pressure reductions that have been put in place while repair works are undertaken. Once these works are finished APA expects that the pipeline will return to nameplate capacity of 232 TJ/day. However, we have been advised by APA that consideration is being given to long term pressure reductions as part of its integrity management program. This would potentially reduce the capacity of the metropolitan pipeline section (downstream of the Brisbane City Gate at Ellengrove) to about 110 TJ/day, with a capacity of 216 TJ/day upstream of the city gate.

2.2.2 Receipt and Delivery Points

The RBP currently has gas **receipt points** located at:

- Argyle
- Condamine
- Kogan North
- Scotia
- Wallumbilla
- Windibri
- Woodroyd (Peat)

Gas **delivery and metering points** are located at:

- Braemar PS
- Brightview (currently inactive)
- Bulwer Island (currently inactive)
- Dalby Bio Refinery
- Dalby Town
- Ellengrove
- Gibson Island
- Lytton
- Mt Gravatt
- Murarrie
- Oakey
- Oakey PS
- Redbank
- Ritchie Road
- Riverview
- Runcorn (currently inactive)
- Sandy Creek
- Swanbank PS (currently inactive)
- Tingalpa
- Toowoomba

2.2.3 RBP Services

The main service provided by the RBP is a **firm service**. Historically this involved gas transport from Wallumbilla to any of the delivery and metering points to the east. More recently, it has included gas injection at mid-line receiving points and transport to delivery and metering points further east.

Following works to introduce bi-directional capability in 2015, a firm service can now be provided in either an easterly or a westerly direction[2].

This firm service includes the following:

a) receipt of gas at the Receipt Points;
b) transportation of gas through the Pipeline, including use of compression facilities installed on the Pipeline;
c) delivery of gas at the Delivery Points;
d) provision of an Overrun facility; and
e) for installations owned and operated by APTPPL, the measurement of gas quantity and quality and of gas pressures.

In addition to the firm service, APA provides other services including:

— **As-Available (AA) service:** gas injection at Wallumbilla and transport to delivery and metering points in an easterly direction, or mid-line receiving points and transport to delivery and metering points in either an easterly or westerly direction. Shippers must hold at least an equivalent level of firm service in order to access AA service. Shippers nominate for AA service on a day-ahead basis. Service is provided subject to availability of capacity in the pipeline system after meeting firm service nominations.

— **Interruptible service:** gas injection at Wallumbilla and transport to delivery and metering points in an easterly direction, or mid-line receiving points and transport to delivery and metering points in either an easterly or westerly direction. Shippers need not hold an equivalent level of firm service in order to access Interruptible service. Shippers nominate for Interruptible service on a day-ahead basis. Service is provided subject to availability of capacity in the pipeline system after meeting firm service and AA nominations.

  – Scheduling priority is given to Firm services, followed by As Available services and then Interruptible services. Where curtailment is required, Interruptible services are first curtailed, followed by As-Available and finally Firm services.

Bespoke Negotiated services are available under terms and conditions, including tariffs, negotiated between the user and APA.

[2] In order to physically transfer gas into other connecting transmission pipelines at the Wallumbilla Hub, compression services are required to raise the gas to the higher operating pressures of the receiving pipelines. Shippers need not purchase Eastbound Service in order to access the Westbound Service.

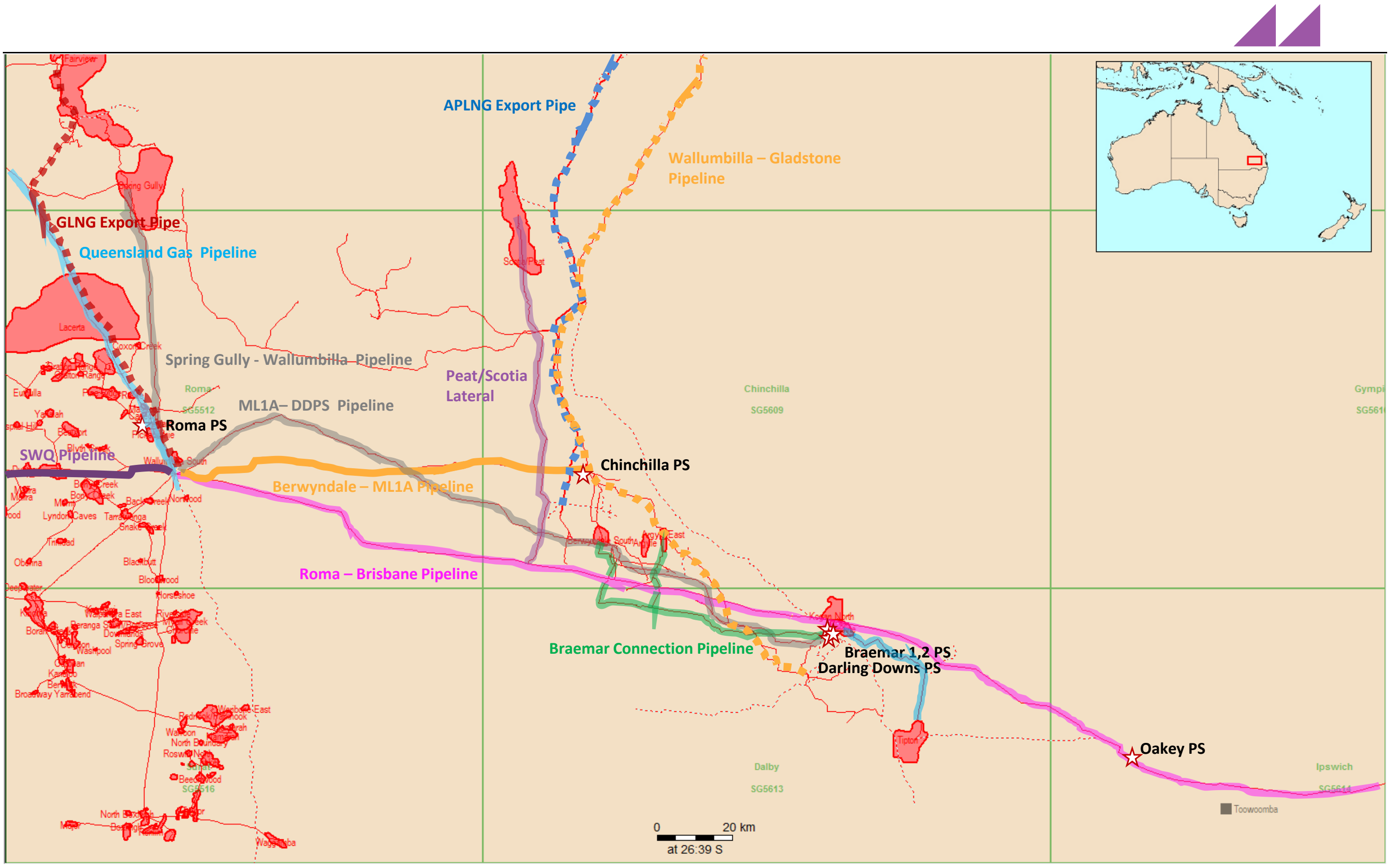
2.3 Interconnection with other transmission pipelines

The RBP traverses the southern Darling Downs, an area that in recent years has seen a major surge in gas production activity with the development of numerous CSG fields in the Surat Basin.

Early CSG developments in the Surat Basin were aimed at domestic gas sales in south east Queensland, with the RBP providing the sole means of access to this market. More recently, large scale CSG projects in the region have been established to supply gas into LNG export facilities in Gladstone. The RBP is not a primary source of transport services for the CSG LNG projects; the three LNG projects have each developed their own dedicated gas gathering, processing, compression and transportation systems. However some CSG producers in the area have, from time to time, used services on the RBP as a means of providing operational flexibility, allowing gas to be temporarily redirected to underground storage facilities, gas-fired generators, swap arrangements with other LNG operators and/or short-term or spot gas buyers.

The extensive upstream CSG developments in the Surat Basin region over the past decade have also seen the establishment of numerous gas gathering and transmission pipelines, some of which connect to the RBP. Others represent alternative transport pathways that effectively bypass the RBP. **Figure 2.6** shows the location of the RBP relative to other gas transmission pipelines and gas-fired electricity generators in the Darlings Downs region. Different pipeline systems have been colour coded to help distinguish the various assets and their inter-relationships:

FIGURE 2.6 ROMA–BRISBANE PIPELINE LOCATION RELATIVE TO OTHER GAS TRANSMISSION PIPELINES AND GAS-FIRED POWER STATIONS IN THE DARLING DOWNS AREA



SOURCE: ACIL ALLEN CONSULTING. BASE MAP FROM ENCOM GPINFO

- The **RBP** (highlighted in pink) traverses the whole area, from the Wallumbilla hub near Roma in the west to Toowoomba in the east. The RBP continues east, beyond the map boundary, to major market centres in the Ipswich, Brisbane and Gold Coast areas.
- The RBP connects to the **South West Queensland Pipeline (SWQP)** at Wallumbilla (highlighted in dark purple). The SWQP is a bidirectional pipeline. It is capable of carrying gas from Wallumbilla west

to Ballera and then on to Moomba for onward shipping to southern markets via the Moomba to Sydney Pipeline or Moomba to Adelaide Pipeline, or to Mount Isa via the Carpentaria Pipeline. The SWQP is also capable of transporting gas from the Ballera injection point east to Wallumbilla for onward delivery via the RBP, the Queensland Gas Pipeline (QGP), or into the gas processing, storage and pipeline transmission systems at Roma which form part of the Santos-operated Gladstone LNG Project.

  - The SWQP operates at a higher pressure than the RBP (up to 14.9 MPa for SWQP, compared to a maximum 9.6 MPa for RBP). Therefore gas can only be delivered from the RBP into the SWQP after compression to increase the pressure of the gas from the RBP to the pressure required for injection into the SWQP.

- The RBP connects to the **Queensland Gas Pipeline (QGP)** at Wallumbilla (highlighted in sky blue). The QGP primarily carries gas from Wallumbilla to domestic markets in Gladstone and Rockhampton.
  - The QGP operates at a higher pressure than the RBP (up to 10.2 MPa for QGP, compared to a maximum 9.6 MPa for RBP). Therefore gas can only be delivered from the RBP into the QGP after compression to increase the pressure of the gas from the RBP to the pressure required for injection into the QGP.
- The **GLNG Export Pipeline** (including the Comet Ridge – Wallumbilla Pipeline and the CRWP Loop Pipeline; highlighted with red dots) closely follows the QGP for much of its length. Gas could potentially be transferred between the GLNG Export Pipeline System and the RBP at Wallumbilla but, once again, the relatively low operating pressure of the RBP means that transfer of gas from RBP into the GLNG system would require access to compression services.
- Origin Energy operates a pipeline system extending from **Spring Gully to Wallumbilla** and then from **Wallumbilla to the Darling Downs Power Station** near Dalby (highlighted in grey).
  - This system links Origin/APLNG's Spring Gully (Bowen Basin) CSG fields and Surat Basin CSG fields with the Darling Downs Power Station which is owned by Origin Energy.
  - The system also acts as a header pipeline, gathering CSG from various APLNG fields for delivery into the **APLNG Export Pipeline** (highlighted in mid-blue dots). While the Origin/APLNG system is proximate to the RBP at Wallumbilla, at the "cross over" between Miles and Dalby, and at the Darling Downs Power Station site, the two systems are not physically connected.
- The **Berwyndale – ML1A (Wallumbilla) pipeline** (highlighted in orange) was built by QGC to enable gas from its CSG fields in the Berwyndale area to be delivered to Wallumbilla. From here, QGC gas can be directed into the RBP for delivery to domestic customers in south east Queensland; into the SWQP for transport to Mount Isa or southern state markets; or into the QGP for transport to Gladstone, Rockhampton and Hervey Bay. Following commissioning of the QCLNG facility at Gladstone, most of this gas is now being directed into the LNG plant via the **Wallumbilla–Gladstone Pipeline**[3] (WGP, owned by APA Group, highlighted by orange dotted line)
- The **Peat – Scotia Lateral** (highlighted in pale purple) carries CSG from the Peat and Scotia CSG fields to the RBP. Since 2000 this has been a significant supplier of gas into the Queensland domestic market. In recent years, the combined production from the two fields has been around 12 PJ/a.
- The 115 km, 16 inch diameter **Braemar Linepack Connection Pipeline**, commissioned in 2006, runs from near Chinchilla to near Dalby. It is highlighted in green on **Figure 2.6**. The pipeline provides operating linepack for Alinta Energy's Braemar–1 Power Station, near Dalby. It connects to the RBP at the Condamine Compressor Station, and also provides direct access to CSG from fields in the Berwyndale/Argyle region, north of the RBP. This system was effectively replicated in 2008 with construction of a 110 km, 16 inch diameter pipeline connecting the Braemar –2 Power Station (Arrow Energy) to the Condamine Compressor Station.
  - While this pipeline provides operating line pack for Braemar–2, the main gas supply to this station comes from Tipton West and Stratheden fields to the south-east, which are connected via the **Tipton West – Daandine Pipeline** (highlighted in pale blue)

The conclusion to be drawn from this analysis is that there are numerous gas transmission pipelines operating in the Surat Basin CSG fields. In particular, the three LNG proponent groups have developed independent upstream (production, processing, compression and transportation) systems

[3] Formerly known as the QCLNG Export Pipeline.

that do not rely on third-party services to secure the transportation path from the CSG production fields to their LNG facilities. While these LNG projects may from time to time make use of services on the RBP to provide operational flexibility, the RBP is not an integral part of any of these delivery systems.

2.4 Connection to gas-fired generators

Gas-fired generators are potentially large users of transportation services provided by the RBP. It is therefore important to understand clearly the extent to which the RBP provides services to gas-fired generators.

There are seven large NEM-scheduled, gas fired generators located in the vicinity of the RBP:

— Roma Power Station
— Condamine Power Station
— Braemar–1 Power Station
— Braemar–2 Power Station
— Darling Downs Power Station
— Oakey Power Station
— Swanbank E Power Station

The non-scheduled Daandine Power Station (Arrow Energy) is located on the Daandine CSG field, close to Dalby.

Three of the NEM-scheduled generators (Roma, Chinchilla and Darling Downs) have no direct connection to the RBP and make no direct use the RBP. To the extent that the operators of these stations (Origin Energy, QGC) have service entitlements on the RBP, they may be able to use those entitlements in ways that indirectly support the operation of the stations. However the main gas supply to these stations does not come via the RBP.

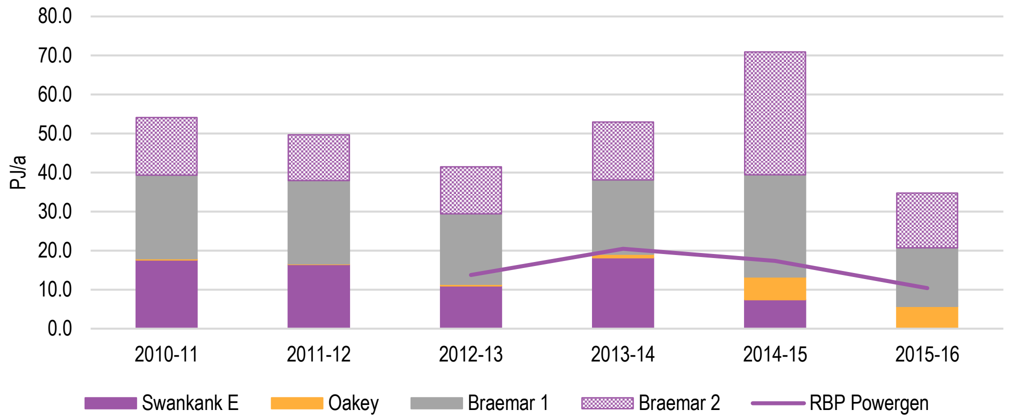
The two Braemar power stations connect to the RBP (at Condamine). They draw some gas from the RBP in order to maintain operational linepack. However, both stations have direct access to other sources of gas supply: from fields to the north-west (Berwyndale, Argyle) in the case of Braemar–1, and from fields to the south-east (Tipton West, Stratheden) for Braemar–2.

Two stations—Oakey and Swanbank E—are reliant on the RBP for fuel supply. Swanbank E ceased operation during 2014 and has not operated since.

Figure 2.7 shows historical average daily gas consumption, by generator, for NEM-scheduled gas-fired power stations that use transportation services on the RBP during the current access arrangement period. The data highlight a number of relevant considerations.

First, it can be seen that Swanbank E ceased generating during 2014–15 (the plant was mothballed in December 2014). The owner Stanwell Corporation determined that it was commercially preferable to sell the plant's contractual gas entitlements to other gas users who were willing to pay a relatively high price, rather than using this gas to generate electricity at lower implied gas values. Based on ACIL Allen's modelling of the NEM, we do not expect Swanbank E to return to service until after 2022 (see section 4.1.2).

FIGURE 2.7 AVERAGE DAILY GAS CONSUMPTION, BY GENERATOR



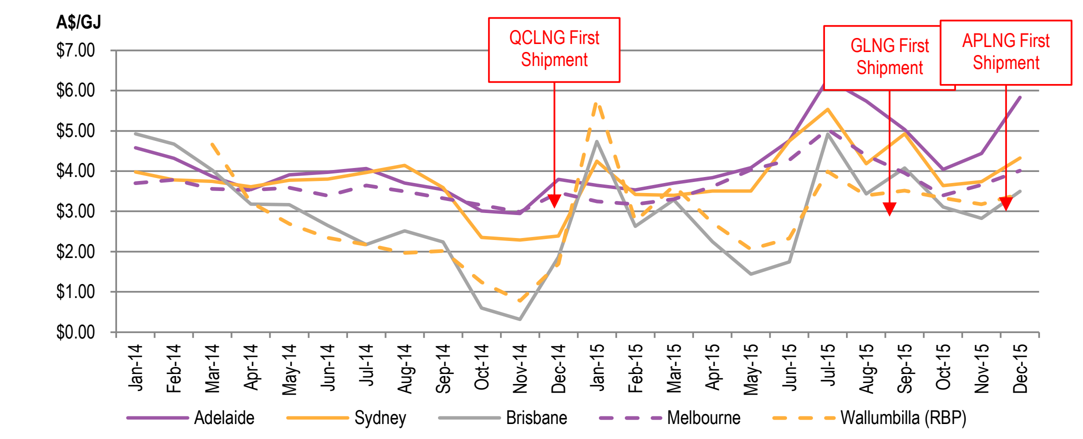
Note: Years are calendar years. Gas consumption calculated from actual plant dispatch as published by AEMO for 2010 – 2015 and 2016 to 16 June; balance of 2016 from ACIL Allen *PowerMark* modelling.

SOURCE: AEMO HISTORICAL DATA FOR THE NATIONAL ELECTRICITY MARKET; ACIL ALLEN POWERMARK MODELLING

Historical plant dispatch has been at considerably higher levels than might have been expected had these plants been run “in merit order” based on full arms-length fuel costs. This is particularly so for open-cycle plants such as Braemar-1, Braemar-2 and Oakey (the latter most noticeably in 2014–15 and 2015–16). A number of factors may have contributed to these outcomes. Initially, high levels of gas-fired plant dispatch were supported by Queensland Government policy (now discontinued) which mandated minimum levels of gas-fired generation and imposed financial penalties on electricity retailers who failed to comply[4]. High levels of gas generation were also a consequence of CSG operators needing to continuously produce CSG fields in order to achieve reserves certification: with limited opportunities to sell gas into a highly-contracted market, the gas-fired generators provided CSG operators with a convenient means of disposing of produced CSG and gaining some commercial return for it. During 2014–15 and 2015–16, levels of gas-fired plant dispatch rose further as excess gas production entered the market, associated with ramp-up of CSG fields in advance of LNG plant commissioning. The impact of “ramp-up gas” was also apparent in spot gas prices which fell to very low levels (particularly in the Brisbane and Wallumbilla markets) prior to the first shipment from the QCLNG plant in late 2014, and to a lesser extent ahead of first shipments from GLNG and APLNG in late 2015 (see **Figure 2.8**).

[4] The Queensland Government “13 per cent gas scheme”, subsequently increased to an 18 per cent target by 2020 – see http://statements.qld.gov.au/Statement/Id/52184

FIGURE 2.8 EASTERN AUSTRALIAN SPOT GAS PRICES, JANUARY 2014 TO JANUARY 2016

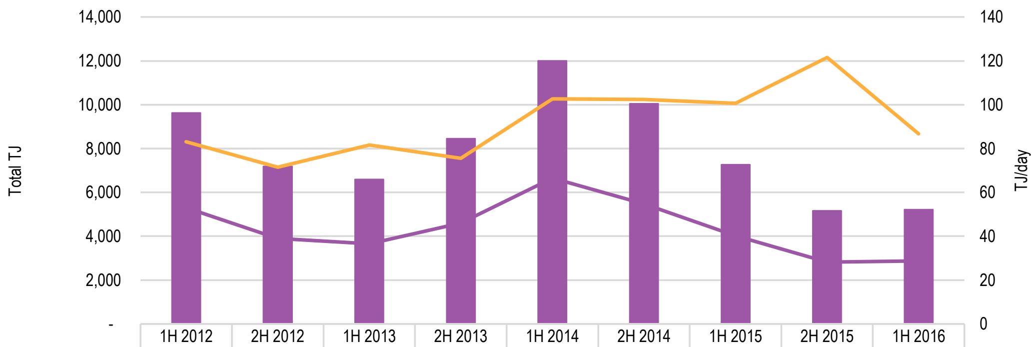


Note: Prices shown are simple monthly average prices (not volume adjusted).

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

The lower levels of average gas consumption shown in **Figure 2.7** for the 2015–16 year reflect actual dispatch data (ex AEMO) from 1 July until 16 June, with modelled dispatch data for the remainder of the year. The recent wind-back in gas-fired generation for the RBP-connected stations is seen clearly in the six-monthly data presented in **Figure 2.9**. Total gas consumption has dropped significantly since 2014, but peak levels remain high reflecting the intermittent operation of OCGT plant.

FIGURE 2.9 FUEL USE BY GAS-FIRED GENERATORS CONNECTED TO THE RBP

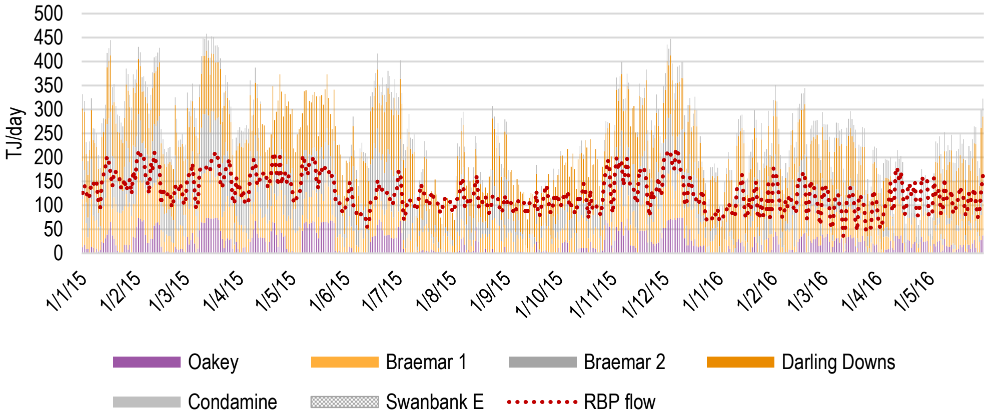


	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Total TJ	9,637	7,191	6,601	8,465	12,004	10,057	7,275	5,171	5,215
Avg TJ/d	52.9	38.9	36.5	45.9	66.5	54.8	40.1	28	29
Max TJ/d	83.0	71.5	81.6	75.6	102.7	102.4	100.7	121.5	86.8

SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

The daily gas consumption data presented in **Figure 2.10** shows that levels of gas-fired generation have declined since commissioning of the GLNG and APLNG plants toward the end of 2015. Continued decline in gas plant dispatch can be expected as LNG production ramps up.

FIGURE 2.10 DAILY GAS CONSUMPTION FOR ELECTRICITY GENERATION—JANUARY 2015 TO JUNE 2016



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DISPATCH DATA

Also plotted on **Figure 2.10** is the total gas flow on RBP over the same period. This represents deliveries to all customers (gas-fired power generation, residential, commercial, small and large industrial), and serves to illustrate the fact that most gas used by electricity generators in southern Queensland in recent times has been delivered by pipelines other than the RBP.

An important conclusion to be drawn from this analysis is that the high levels of gas-fired generation seen in southern Queensland over the current access arrangement period are unlikely to be maintained in future. As discussed in section 3.2.4, we expect to see much lower levels of gas use for power generation in the region over the next access arrangement period.

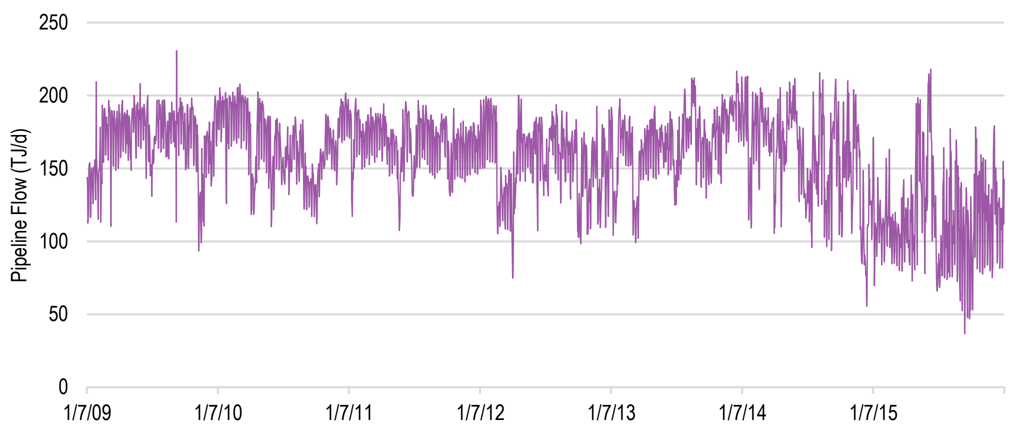
3 HISTORICAL REVIEW

3.1 Pipeline utilisation

Figure 3.1 summarises utilisation of the RBP during the current access arrangement period, based on daily gas flow data published on the AEMO Natural Gas Services Bulletin Board (Report INT 924, INT 925) for the period 1 July 2009 to 30 June 2016. The AEMO actual flow data represents the sum of daily gas quantities measured at all delivery points on the RBP.

ACIL Allen has cross-checked the AEMO data against confidential data provided by APA which shows daily gas injections and withdrawals on the RBP at receipt point/delivery point level, for the period 1 January 2012 to 30 June 2016[5]. This analysis confirms that the AEMO data corresponds to the sum of daily gas deliveries at all metered deliveries points on the RBP.

FIGURE 3.1 RBP DAILY GAS FLOWS: JANUARY 2010 TO JUNE 2016



Note: Daily flow represents sum of deliveries at all delivery points on the RBP.

SOURCE: AEMO NATURAL GAS SERVICES BULLETIN BOARD

Because the AEMO actual flow data represents the sum of daily gas quantities measured at all delivery points on the RBP, it does not distinguish between easterly flows (toward Brisbane) and westerly flows (toward Wallumbilla). Information provided by APA indicates that Western Haul services (toward Wallumbilla), which commenced in mid-2015, now account for a substantial proportion of total deliveries on RBP. The peak rate of Western Haul flow over the period 1 October

[5] The APA meter data is confidential because it reveals commercially-sensitive information about levels of gas consumption for individual customers. In this report we have, where necessary, aggregated the meter data in our analysis in order to avoid revealing information at individual customer level.

2015 to 30 June 2016 was 118 TJ/day, at an average rate of 24 TJ/day. The average daily rate of Western Haul flow was 75 TJ/day during June 2016. At the same time peak rates of eastern flow have declined from more than 200 TJ/day prior to commencement of Western Haul services to around 130 TJ/day during the first six months of 2016. The future outlook for Western Haul service is discussed in section 4.6.

The data presented in **Figure 3.1** show that there has been a very significant reduction in average daily throughput on RBP since late 2014, and in particular since mid-2015. These trends are evident in the summary data presented in **Table 3.1**. From FY 2010 to 2015, average throughput ranged from 155 to 169 TJ/day. Peak throughput over the same period ranged between 198 and 231 TJ/day. Annual aggregate throughput ranged from a maximum of 61.5 PJ in FY 2010 to a minimum of 56.5 PJ in FY 2013. However, FY2016 saw a sharp drop in average daily throughput (to 116 TJ/day) and in annual aggregate throughput (to 42.4 PJ) while peak throughput remained similar to previous years at 218 TJ/day. During the first six months of 2016 average daily throughput has fallen further to 111 TJ/d. The peak flow rate so far in 2016 has only reached 179 TJ/day (this may yet be exceeded toward the end of the year with higher seasonal gas demand for electricity generation). Aggregate throughput is down to 20.2 PJ for the six month period (around 40 PJ/a on a pro rata annualised basis).

Three factors that have contributed to the recent sharp decline in gas flow on the RBP are:

— Mothballing of the Swanbank E power station. The station has not run since the end of November 2014. Prior to closure of the station, Swanbank E drew an average 44 TJ/day from the RBP, with a peak rate of 69 TJ/day.[6]
— Closure of the BP Bulwer Island refinery in mid-2015. ACIL Allen estimates that the BP refinery drew an average 26 TJ/day of gas from RBP, principally for co-generation operations. The BP load was relatively flat; ACIL Allen estimates about 85 per cent load factor which implies a peak flow rate of approximately 30 TJ/day.
— Reduced availability of surplus CSG following commissioning of the first five LNG trains at Gladstone, commencing in December 2014 with the fifth train (GLNG 2) coming on line in May 2016.

TABLE 3.1 RBP HISTORICAL GAS FLOW DATA

Financial Year	Average Throughput	Peak Day Throughput	Annual Total
	TJ/day	TJ/day	TJ
2009–10	169	231	61,509
2010–11	167	208	60,911
2011–12	167	198	61,290
2012–13	155	200	56,537
2013–14	167	217	61,120
2014–15	158	216	57,776
2015–16	116	218	42,448

Note: Based on actual flow data for period 1 July 2009 to 30 June 2016

SOURCE: ACIL ALLEN ANALYSIS OF AEMO NATURAL GAS SERVICES BULLETIN BOARD DATA

3.2 Historical gas demand

The direct customers of the RBP include gas-fired power generators (Stanwell Corporation Swanbank E; ERM Oakey; Alinta Braemar), energy retailers (Origin, AGL) and major industrial users. The energy retailers contract for capacity on RBP in order to take delivery of wholesale gas which is then on-sold to their retail customers (residential, commercial and industrial), generally via the distribution networks operated by Allgas Energy and Australian Gas Networks. In this section we review the historical gas demand associated with these customer groups.

[6] ACIL Allen calculations based on AEMO data on generator dispatch.

3.2.1 Total gas deliveries on RBP

Figure 3.2 summarises total gas deliveries on RBP over the financial years 2010–11 to 2015–16, showing major load groups. As indicated on this chart, the estimates of total deliveries by major load group match closely with the historical actual flow data recorded by AEMO.

Total Retail averages of around 16 PJ/a, including Retail Tariff V and Retail Tariff D[7] values, reflect the approved volume forecasts for the Allgas Energy and Australian Gas Networks distribution networks for the current access arrangement period (1 July 2011 to 30 June 2016). We have augmented this forecast data with actual deliveries using confidential meter-level data provided by APA. This data covers the period 1 January 2012 to 30 June 2016.

Table 3.2 compares the approved retail volume forecasts with actual deliveries via RBP to retail market customers for the years 2012–13 to 2015–16 (the only full financial years for which ACIL Allen has access to meter data). The data show that actual deliveries via RBP to retail market customers have been between 1.6% and 4.9% below the approved retail demand forecast levels.

TABLE 3.2 COMPARISON OF APPROVED RETAIL DEMAND FORECAST WITH METERED DELIVERIES

Financial Year	Retail Tariff V + D Approved Forecast	Metered Deliveries	Metered/Forecast
	TJ/a	TJ/a	Per Cent
2012–13	15,916	15,187	95.4%
2013–14	15,955	15,168	95.1%
2014–15	16,067	15,756	98.1%
2014–15	16,328	16,073	98.4%

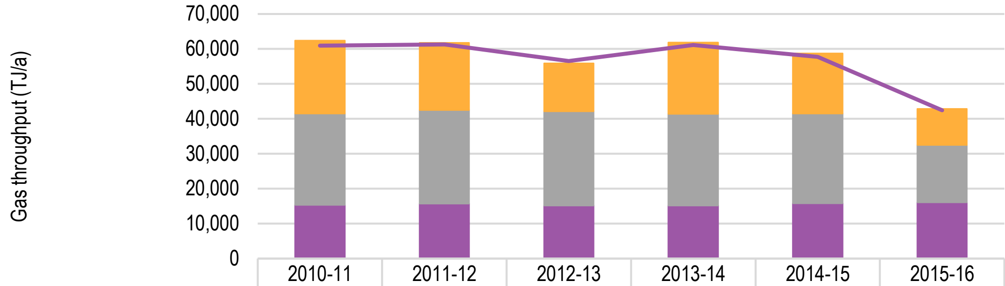
SOURCE: APPROVED FORECASTS FROM ALLGAS, AGN ACCESS ARRANGEMENTS; ACTUAL DELIVERIES TO RETAIL MARKET METERS ON RBP FROM CONFIDENTIAL DATA PROVIDED BY APA.

The **Large Industrial** customer group reflects ACIL Allen's current understanding of gas consumption within this group, which is generally confirmed by individual meter data provided in confidence by APA.

The **Total Powergen** data for the years 2012–13 to 2015–16 includes actual deliveries via RBP to Oakey, Swanbank E and Braemar 1 and Braemar 2 power stations, as revealed in confidential meter data provided by APA. For other years, gas consumption at Oakey and Swanbank E power stations have been calculated[8] on the basis of actual dispatch of these stations as recorded in public domain AEMO generation data. Similar calculations have been made for the Braemar stations, which draw most of their fuel gas from pipelines other than the RBP. In order to determine the proportion of gas consumed at the Braemar stations that is delivered via RBP, we compared metered deliveries for the years 2012–13 to 2015–16 with the calculated total gas consumption at these stations in those years. This allowed us to estimate the average proportion of total Braemar powergen gas feed delivered via the RBP. This ratio was then applied to total Braemar gas consumption in order to estimate RBP deliveries to Braemar in years for which meter data was not available.

[7] Tariff V represents those customers metered using volumetric meters (residential and commercial customers) whereas Tariff D represents those customers connected to the distribution system and metered on demand meters (generally small industrial customers).
[8] The calculation of gas consumption values involves taking AEMO dispatch data (GWh sent out) and applying ACIL Allen's in-house assumptions regarding heat rates for individual generation units.

FIGURE 3.2 HISTORICAL TOTAL GAS DELIVERIES ON RBP, BY MAJOR CUSTOMER GROUP



	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Total Powergen	20,869	19,274	13,793	20,469	17,331	10,386
Total Large Industrial	26,200	26,807	26,923	26,186	25,696	16,450
Total Retail	15,332	15,675	15,187	15,168	15,756	16,073
Historical Actual Flow	60,911	61,290	56,537	61,120	57,776	42,448

Note: 2015–16 represents a combination of actual gas for power generation (to end of May) inferred from AEMO generation dispatch data, and forecast gas consumption based on detailed electricity market modelling.

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL ACTUAL FLOW DATA FROM AEMO.

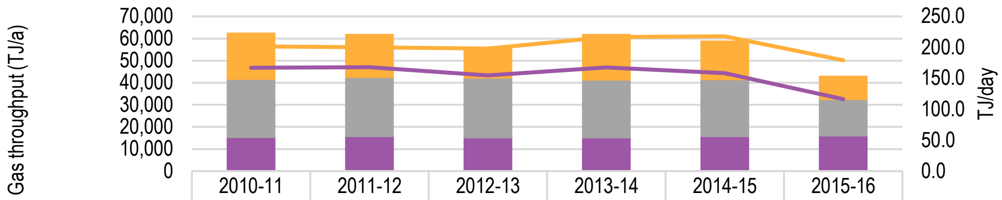
Figure 3.2 illustrates a number of significant features of the recent historical performance of RBP:

— Throughput in 2013–14 and 2014–15 was strong, driven by high levels of dispatch of gas-fired power stations. The drop in throughput resulting from closure of Swanbank E power station in December 2014 was offset by unusually high levels of gas delivery to other power stations.

— Total throughput fell sharply in 2015–16 as a result of the closure of the BP Bulwer Island refinery and co-generation plant (from July 2015). Abnormally high dispatch of the Oakey gas-fired power station (utilising ramp-up CSG in advance of commissioning of the GLNG and APLNG plants at Gladstone) was not sufficient to offset the loss of the BP Bulwer Island load and the earlier loss of Swanbank E. These closures, together with a return of the Oakey and Braemar stations to more “normal” running conditions following commissioning of the Gladstone LNG facilities and the continuing shutdown of Swanbank E, mean that total gas throughput on RBP can be expected to fall further in the 2016–17 financial year.

Figure 3.3 superimposes on the annual consumption data curves showing the average and peak daily flow on RBP. From 2010–11 to 2013–14, the annual system average load factor (average daily flow/peak daily flow) varied between 77 and 83 per cent. In 2014–15 system average load factor declined to 73 per cent following the closure of the Swanbank E CCGT power station mid-way through the year (December 2014). In 2015–16 system average load factor fell further, to 65 per cent, with the continued shutdown of Swanbank E and closure of the BP Bulwer Island refinery and cogeneration facility (July 2015). The outlook now is for an even “peakier” low load factor on the RBP system, with the loss of BP Bulwer Island load—a large, relatively stable load—exacerbated by reduced availability of “ramp gas” CSG following commissioning of the three Gladstone LNG plants. This is expected to lead to decreased dispatch, lower capacity factor and reduced pipeline load factor for the gas-fired power generation plants currently utilising the RBP (Oakey, Braemar 1 & 2).

FIGURE 3.3 HISTORICAL TOTAL ANNUAL, AVERAGE DAY AND PEAK DAY GAS DELIVERIES



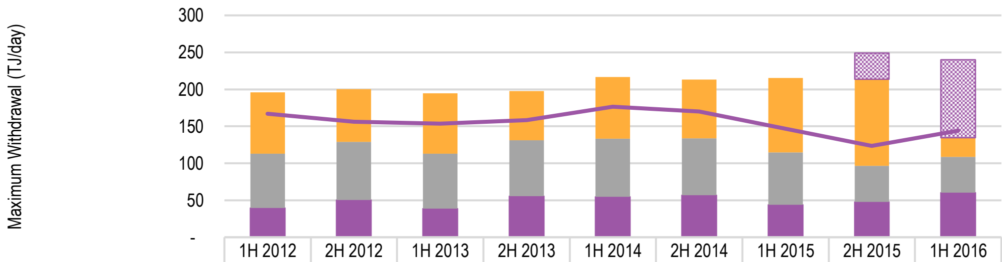
	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Total Powergen	20,869	19,274	13,793	20,469	17,331	10,386
Total Large Industrial	26,200	26,807	26,923	26,186	25,696	16,450
Total Retail	15,332	15,675	15,187	15,168	15,756	16,073
Average daily flow	166.9	167.9	154.9	167.5	158.3	116.3
Peak daily flow	201.7	200.2	197.8	216.6	217.9	179.1

SOURCE: ACIL ALLEN ANALYSIS OF CONFIDENTIAL DATA PROVIDED BY APA GROUP

Contributions to peak day demand

In **Figure 3.4** we have used detailed meter data provided by APA to determine the total system peak day demand for each six-month period since 1 January 2012, and then determined the contribution that each customer sector (retail, industrial, powergen and Western Haul flow to Wallumbilla) made to total demand on that peak day. The contribution of each customer sector to demand on the system peak day does not necessarily correspond to the peak demand for that customer sector during the period, because each customer sector is likely to see peak demand on a different day through the period. This chart highlights the fact that there has been a very significant change in the patterns of peak system demand in the RBP since mid-2015 when Western Haul services commenced. East-bound peak deliveries have fallen from around 215 TJ/day to 150 TJ/day reflecting a sharp downturn in GPG contribution to peak day demand and the closure of the BP Bulwer Island cogeneration plant. At the same time, Western Haul service contributed 118 TJ/day to peak system demand in the first half of 2016.

FIGURE 3.4 CONTRIBUTIONS TO PEAK DAY WITHDRAWALS—TOTAL SYSTEM DEMAND

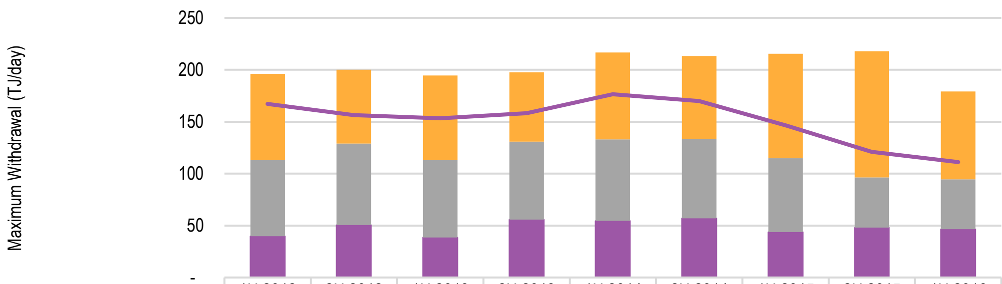


	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Westernhaul	-	-	-	-	-	-	-	35	105
Powergen	83	71	82	67	84	79	101	117	26
Industrial	73	79	75	75	79	77	71	49	48
Retail	40	50	39	56	55	57	44	48	60
Average Withdrawal	167	156	153	158	177	170	147	124	144

SOURCE: ACIL ALLEN ANALYSIS OF CONFIDENTIAL DATA PROVIDED BY APA GROUP

Figure 3.5 shows the corresponding analysis for Eastern Haul business only (excluding Western Haul). Because Western Haul service only commenced during the second half of 2015, the results for earlier periods are identical to those shown in **Figure 3.4**. However, for the last two periods (2H2015 and 1H2016) the peak days for Eastern Haul business are different from the total system peak days and so the contributions by customer sector are different. In particular, the peak day contribution to powergen is larger. The Eastern Haul peak day is potentially more relevant in terms of future contracting for firm service because, as discussed in section 6.3, users of the Western Haul service are likely in future to rely primarily on non-firm (as available and interruptible) services.

FIGURE 3.5 CONTRIBUTIONS TO PEAK DAY WITHDRAWALS—EASTERN HAUL ONLY



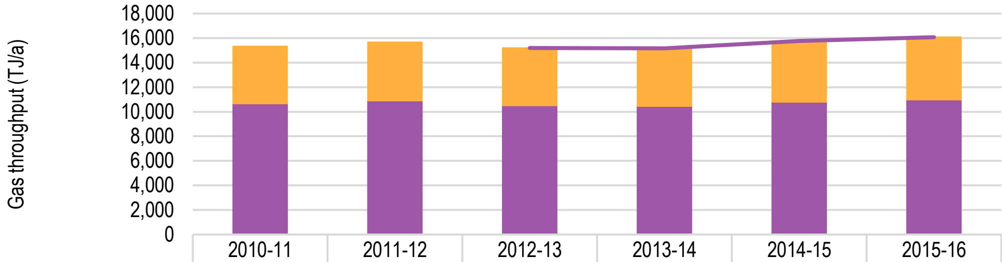
	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Powergen	83	71	82	67	84	79	101	121	85
Industrial	73	79	75	75	79	77	71	48	48
Retail	40	50	39	56	55	57	44	48	46
Average Withdrawal	167	156	153	158	177	170	147	121	111

SOURCE: ACIL ALLEN ANALYSIS OF CONFIDENTIAL DATA PROVIDED BY APA GROUP

3.2.2 Retail customers

The Retail Tariff V and Retail Tariff D values shown in **Figure 3.6** for 2012–11 and 2011–12 reflect the approved volume forecasts for the Allgas Energy and Australian Gas Networks distribution networks for the current access arrangement period (1 July 2011 to 30 June 2016). For the years 2012–13 to 2015–16, **Figure 3.6** shows actual deliveries to retail customers (total) using confidential meter-level data provided by APA.[9] The total retail deliveries have been divided between Tariff V (residential, commercial and small industrial) and Tariff D (larger industrial) customer groups based on the historical split between these groups (approximately 31:69 split).

FIGURE 3.6 RETAIL CUSTOMERS: HISTORICAL GAS DELIVERIES



	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Retail Tariff V	4,664	4,784	4,666	4,719	4,959	5,099
Retail Tariff D	10,668	10,891	10,520	10,448	10,797	10,973
Retail metered (APA)			15,187	15,168	15,756	16,073

Retail Tariff D Retail Tariff V Retail metered (APA)

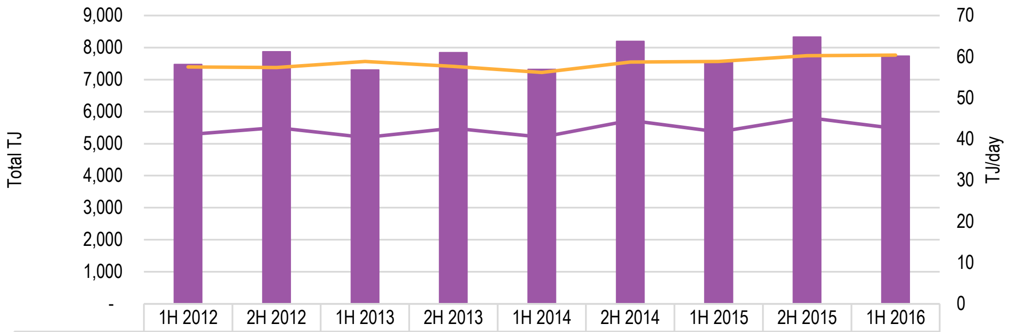
SOURCE: ACIL ALLEN ANALYSIS

Figure 3.7 shows at six-monthly intervals the total annual deliveries, average and peak daily demand for retail customers (residential, commercial and small to medium industrial) served by the RBP, based on confidential meter-level data provided by APA. The data, which covers the period 1 January 2012 to 30 June 2016, shows that average and peak demand in the retail sector has grown modestly,

[9] As discussed in section 3.2.1, actual deliveries to retail market meters located on the RBP have been between 1.6% and 4.9% below the approved retail forecast demand during the current access arrangement period.

from around 42 TJ/day to 44 TJ/day (average) and from 57 TJ/day to 60 TJ/day (peak) over the period.

FIGURE 3.7 RETAIL CUSTOMERS: HISTORICAL DELIVERIES, AVERAGE AND PEAK DAILY DEMAND



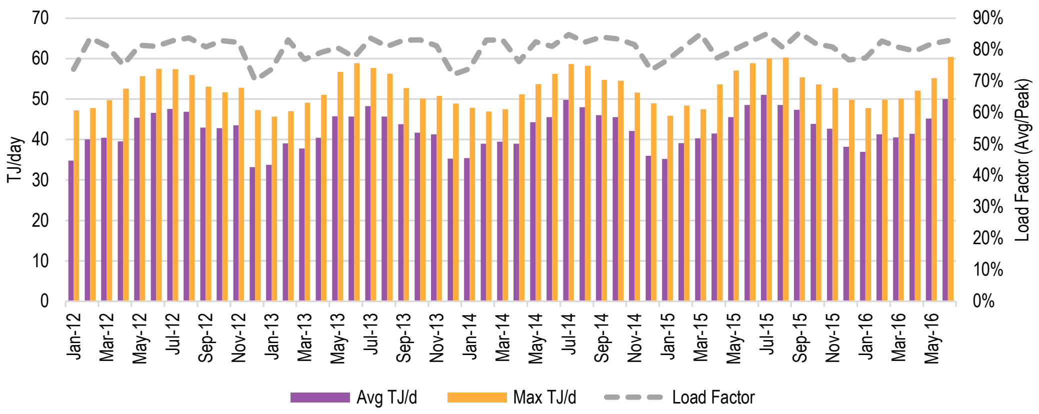
	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Total TJ	7,481	7,876	7,311	7,847	7,321	8,203	7,552	8,332	7,741
Avg TJ/d	41.1	42.8	40.4	42.6	40.4	44.6	41.7	45	43
Max TJ/d	57.5	57.4	58.9	57.7	56.2	58.7	58.9	60.3	60.4

SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

The monthly data presented in **Figure 3.8** shows that there is a moderate level of seasonal variation in the retail load, with peak demand of up to 60 TJ/day during the winter months and around 45 TJ/day during summer. However, the variation in load factor sees the greatest spread between average and peak demand in the summer months when load factor falls to around 70 per cent, compared to 80 to 85 per cent during the winter months. The relatively high load factor in winter reflects the fact that there is little use of gas for space heating in the southeast Queensland market: the main contributor to the seasonal winter increase in average and peak demand is most likely to be higher gas use for water heating as a result of lower ambient water temperatures.

The meter data provides no insight into the split between small customer (Tariff V) and larger customer (Tariff D) usage. Anecdotal evidence suggests that, despite some distribution-connected industrial customers having reduced their contract MDQ, demand across the Tariff D group has been relatively stable. For the Tariff V customer group, the approved volume forecasts for the distribution networks for the current access arrangement period anticipated an increase in connection numbers offset by lower gas use per connection, resulting in a modest level of overall growth in Tariff V demand. We would therefore expect the volume split between Tariff V and Tariff D consumption to have shifted slightly toward Tariff V customers over recent years.

FIGURE 3.8 RETAIL CUSTOMERS: HISTORICAL MONTHLY AVERAGE AND PEAK DAY DELIVERIES

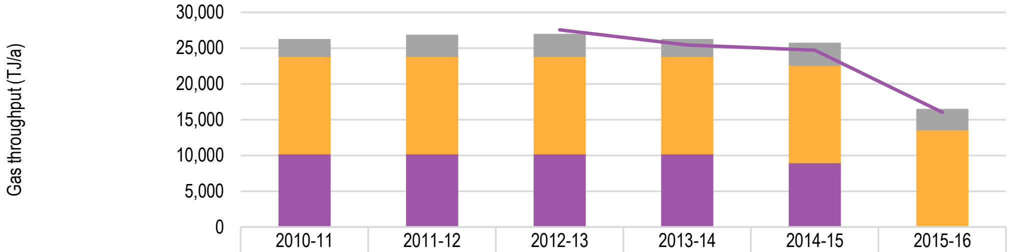


SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

3.2.3 Large industrial users

The estimated historical gas deliveries to Large Industrial Customers (broadly defined as those industrial customers that are directly metered at transmission level, rather than being serviced by energy retailers) are shown in **Figure 3.9**. The quantities shown for Incitec Pivot and BP Bulwer Island reflect ACIL Allen's understanding of the usual annual gas consumption of these customers, as reflected in our in-house gas market model. The "other industrial" category represents a number of other transmission-connected industrial customers, the consumption rates for which have been deduced from AEMO flow data with the aid of APA meter data for the period 2012–13 to 2015–16.

FIGURE 3.9 LARGE INDUSTRIAL CUSTOMERS: HISTORICAL GAS DELIVERIES

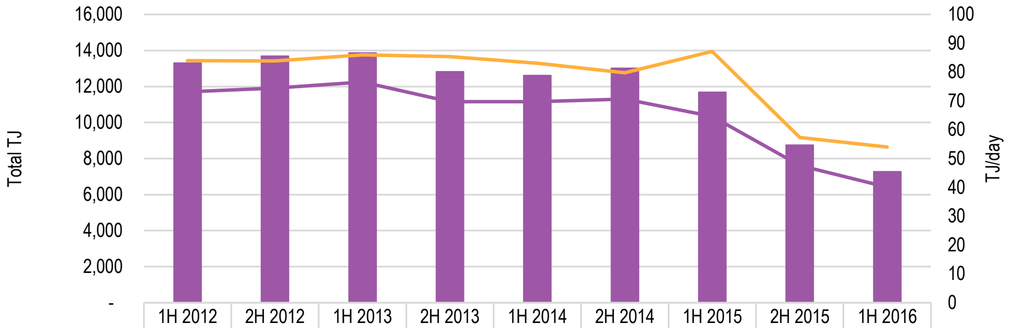


	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
Other industrial	2,350	2,957	3,073	2,336	3,096	2,850
Incitec Pivot	13,600	13,600	13,600	13,600	13,600	13,600
BP Bulwer Island	10,250	10,250	10,250	10,250	9,000	0
Large Industrial metered (APA)			27,560	25,458	24,706	16,037

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA (PUBLIC) AND APA DATA (CONFIDENTIAL)

Figure 3.10 shows for six-monthly intervals the total deliveries, average and peak daily demand for large industrial customers, based on confidential meter-level data provided by APA. The data, which covers the period 1 January 2012 to 30 June 2016, shows that average demand in the large industrial sector declined over this period. The closure of the BP Bulwer Island refinery and cogeneration plant (which ceased production in July 2015) is clearly reflected in these data. Maintenance outages at other industrial facilities during the first half of 2016 further suppressed deliveries during this period. Average daily demand for large industrial customers declined from 73 TJ/day to 40 TJ/day over the period, with the figure for 1H2016 impacted by the previously mentioned maintenance shutdowns; peak demand has declined over the same period from 84 TJ/day to 54 TJ/day.

FIGURE 3.10 LARGE INDUSTRIAL CUSTOMERS: HISTORICAL DELIVERIES, AVERAGE AND PEAK DAILY DEMAND

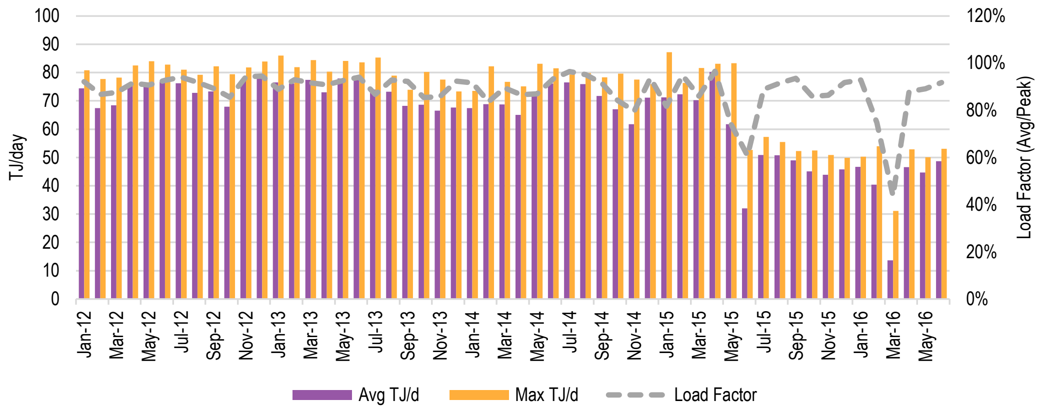


	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Total TJ	13,313	13,696	13,864	12,835	12,623	13,015	11,691	8,757	7,280
Avg TJ/d	73.1	74.4	76.6	69.7	69.7	70.7	64.6	48	40
Max TJ/d	84.0	83.9	86.0	85.4	83.1	79.8	87.2	57.3	54.0

SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

The monthly data presented in **Figure 3.11** shows that there is no seasonal variation in the large industrial load, which is generally flat with a high load factor typically around 85 to 90 per cent. The results for June 2015 and March 2016 are anomalous, reflecting both the cessation of operations at BP Bulwer Island and major shutdowns at other large industrial plants. The monthly data confirms a fall in average daily demand for large industrial customers from around 70 TJ/day to about 45 TJ/day in a typical month. The corresponding fall in peak demand is from about 80 TJ/day to about 50 TJ/day.

FIGURE 3.11 LARGE INDUSTRIAL CUSTOMERS: HISTORICAL MONTHLY AVERAGE AND PEAK DAY DELIVERIES

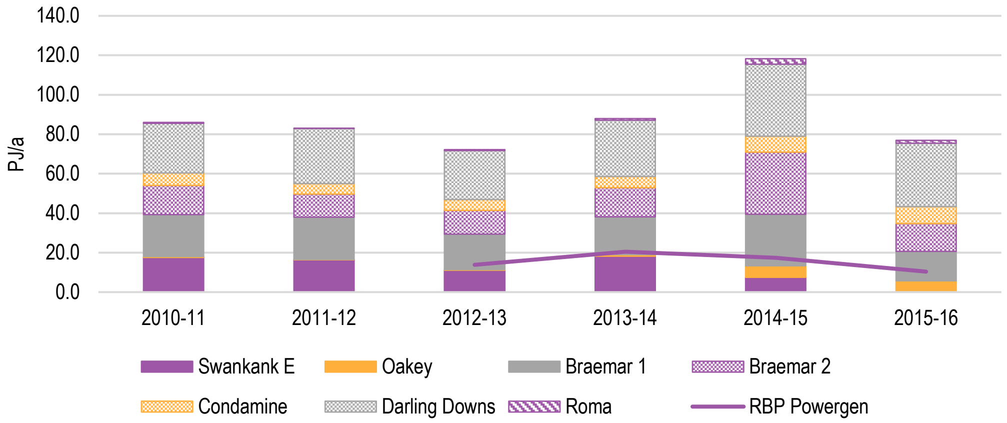


SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

3.2.4 Gas for Power Generation

Figure 3.12 shows inferred gas consumption for all gas-fired power generators in southern Queensland over the period 2010–11 to 2015–16, and compares the results with actual metered deliveries via the RBP to GPG sites for financial years 2012–13 to 2015–16. The data shows that the RBP serves only a relatively small proportion of the gas-fired power generation load in southern Queensland. Of the seven NEM-scheduled gas-fired generators in southern Queensland, only two (Swanbank E and Oakey) are reliant on RBP for gas supply. Two other stations (Braemar 1 and 2) take a relatively small proportion of their total gas feed from RBP. Three stations (Roma, Condamine and Darling Downs) are not reliant on RBP for gas supply.

FIGURE 3.12 SOUTHERN QUEENSLAND GPG CONSUMPTION HISTORY

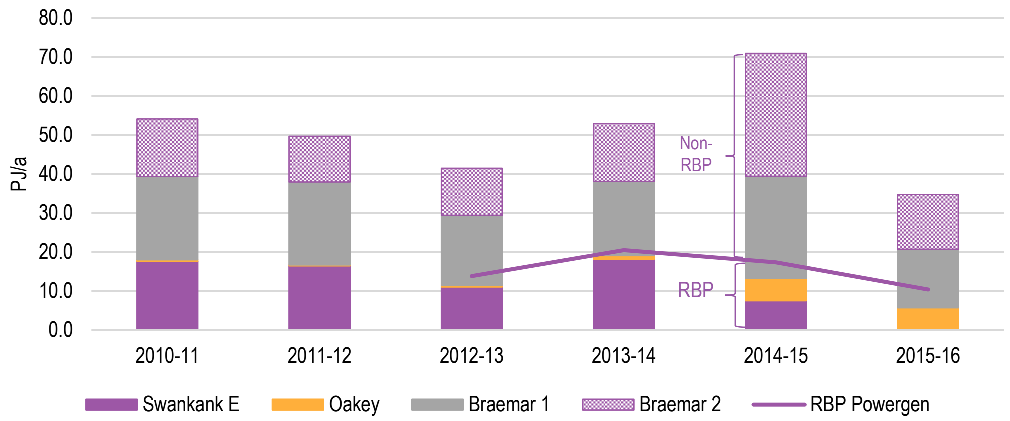


Note: Gas use inferred from AEMO public data on dispatch by generating unit, applying ACIL Allen data on individual generating plant heat rates.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO NEM DATA; DELIVERIES TO GPG METER SITES (2012–13 TO 2015–16) FROM APA METER DATA (CONFIDENTIAL)

Figure 3.13 shows the same data as **Figure 3.12** except that it excludes gas consumed in the stations that are not connected to the RBP. It shows the total gas consumption, from all supply sources (RBP and non-RBP), for the four gas-fired stations connected to the RBP. The purple line shows the total metered deliveries of gas from the RBP to these four stations. Given that all of the gas consumed by Swanbank E and Oakey is delivered via RBP, it can be seen that only a small proportion of the gas consumed in the Braemar 1 and Braemar 2 power stations is sourced from RBP.

FIGURE 3.13 GPG CUSTOMERS OF RBP: HISTORICAL GAS CONSUMPTION AND TOTAL RBP DELIVERIES



Note: Gas use inferred from AEMO public data on dispatch by generating unit, applying ACIL Allen estimates of individual generating plant heat rates.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO NEM DATA; DELIVERIES TO GPG METER SITES (2012 TO 2014) FROM APA METER DATA (CONFIDENTIAL)

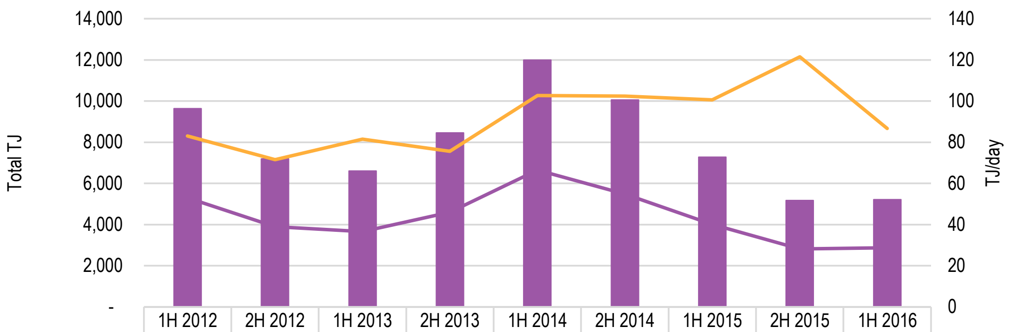
A major factor contributing to the recent sharp drop in GPG gas consumption was the closure of the Swanbank E power station. In late 2014 Stanwell Corporation announced that it would put Swanbank E into "cold storage" on 1 December 2014 "for up to three years", citing an expectation that sale of its gas entitlements would yield more value than using those entitlements to generate electricity.[10] On the basis of Stanwell's announcement, Swanbank E may return to service in late 2017. However, as discussed in section 4.1.2, ACIL Allen's electricity market modelling indicates that market justification for a restart of operations at Swanbank E is likely to be significantly later—after 2022—and dependent on re-introduction of an explicit carbon price as well as re-contracting for low-priced gas.

Oakey PS and other southern Queensland gas-fired generators ran at higher than usual levels during 2014–15 and 2015–16, taking advantage of abundant ramp-up CSG that was available ahead of the commissioning of LNG trains at Gladstone.

Figure 3.14 shows for six-monthly intervals the total deliveries, average and peak daily demand at GPG sites served by the RBP, based on confidential meter-level data provided by APA. The data highlights the high level of GPG usage in 2014 during the period of CSG ramp-up prior to commissioning of the GNLG and APLNG plants at Gladstone. Consumption during 2015 and the first half of 2016 remained strong considering that this data includes the shut-down of Swanbank E in December 2014.

[10] Stanwell Corporation Fact Sheet "Swanbank E Power Station, December 2014 viewed at http://www.stanwell.com/wp-content/uploads/Swanbank-E-December-2014.pdf

FIGURE 3.14 GPG CUSTOMERS: HISTORICAL DELIVERIES, AVERAGE AND PEAK DAILY DEMAND



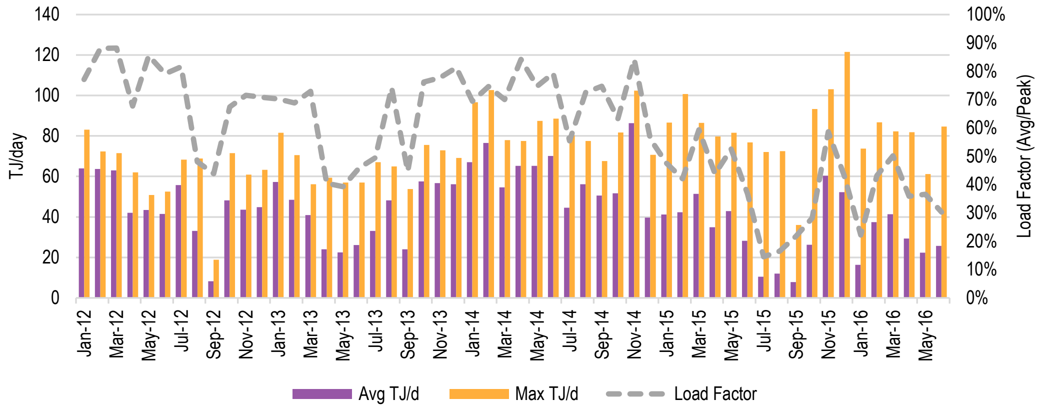
	1H 2012	2H 2012	1H 2013	2H 2013	1H 2014	2H 2014	1H 2015	2H 2015	1H 2016
Total TJ	9,637	7,191	6,601	8,465	12,004	10,057	7,275	5,171	5,215
Avg TJ/d	52.9	38.9	36.5	45.9	66.5	54.8	40.1	28	29
Max TJ/d	83.0	71.5	81.6	75.6	102.7	102.4	100.7	121.5	86.8

Note: 2011–12 data relates to last six months of the financial year only (1 January to 30 June).

SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

The monthly data (**Figure 3.15**) show a significant reduction in average GPG deliveries over the period December 2014 through to September 2015. This coincided with the first cargoes from QCLNG Train 1 (December 2014) and GLNG Train 1 (October 2015). Average deliveries then rose sharply ahead of the commissioning of APLNG January 2016 and QCLNG Train 2 (May 2016). The decline in average daily GPG consumption following commissioning of the various LNG trains is consistent with excess “ramp-up” gas being redirected to the LNG facilities. At the same time, maximum daily GPG use has remained relatively high—up to 120 TJ/day—indicating that the overall load factor is falling. Whereas GPG load factor ranged between 70 and 80 per cent for most of 2013–14, it fell to around 30 per cent by the end of 2015–16.

FIGURE 3.15 GPG CUSTOMERS: HISTORICAL MONTHLY AVERAGE AND PEAK DAY DELIVERIES



SOURCE: ACIL ALLEN ANALYSIS OF APA METER DATA

4

FORECAST GAS DEMAND

In this Chapter, the Base Case forecast for east-bound annual throughput, average daily throughput and peak demand on RBP is presented, together with Low Case and High Case alternative forecasts that incorporate some of the binary uncertainties to the Base Case forecast, specifically whether or not Incitec Pivot Gibson Island plant will continue to operate beyond its currently contracted gas supply arrangements, and the timing of return to service of the Swanbank E CCGT plant.

4.1 Base Case Forecast – Methodology and Key Assumptions

ACIL Allen has developed a Base Case forecast of east-bound annual gas throughput, average daily throughput and peak day throughput on the RBP for the upcoming access arrangement period (1 July 2017 to 30 June 2022) by separately projecting demand in the following customer classes:

— Retail gas (residential, commercial, small and medium industrial)
— Large industrial
— Gas-fired Power Generation (GPG)

For retail gas, the steps in formulating the forecast were as follows:

1. We took as our starting point the Access Arrangement Information (AAI) for the Allgas Energy and Australian Gas Networks South East Queensland gas distribution network forecasts for the access arrangement period 1 July 2011 to 30 June 2016. These include historical retail demand for 2006–07 to 2009–10, plus the forecast demand (Tariff V Residential, Tariff V Commercial and Tariff D) for 2010–11 to 2015–16.
2. We used a simple trend function to extrapolate the demand by customer class to 2020–21.
3. We established the percentage that each retail customer class bears to the total forecast demand over the period to 2020–21.
4. We then substituted the actual total retail demand for years 2012–13 to 2015–16 (as recorded in the APA meter data) for the AAI forecasts for those years; actual demand ranged between 1.6 per cent and 4.9 per cent below forecast demand in those years.
5. The adjusted total retail demand was then pro-rated to individual customer classes using the percentages determined in step 3.
6. Finally, we used a trend function to extrapolate the historical data (2009–10 to 2015–16) for each class over the forecast period to 2021–22.

For large industrial sites, we have used ACIL Allen's current understanding of gas consumption within this group, which is generally confirmed by individual meter data provided in confidence by APA. Large industrial customers include the Incitec Pivot Gibson Island fertiliser plant, BP Bulwer Island refinery and co-generation plant and other industrial users in the Port of Brisbane and Darling Downs areas.

The BP oil refinery ceased operations on 1 July 2015. With a capacity of around 100,000 barrels per day it was one of the smaller Australian refineries. Gas was used for cogeneration (steam, electricity) and hydrogen manufacture. There is currently no prospect of the refinery resuming operations; recent history suggests that when such Australian refineries close they do not re-open.[11] We therefore exclude the BP Bulwer Island load (previously around 10.3 PJ/a) from all future scenarios.

There is also a degree of uncertainty regarding the longer-term future for the Incitec Pivot Gibson Island fertiliser plant which, with annual demand of 13–14 PJ/a, is the largest single-location load in southeast Queensland. Incitec Pivot produces ammonia, urea and ammonium sulphate Gibson Island. The plant has the capacity to manufacture 300,000 tonnes of ammonia, 280,000 tonnes of urea and 200,000 tonnes of ammonium sulphate. Natural gas is used as a feedstock for the production of ammonia, which in turn is used in the manufacturing of fertiliser products including urea and ammonium sulphate.

In September 2004 Incitec announced[12] the signing of 10-year natural gas supply and transport agreements with:

— Origin Energy for about 50 per cent of its gas supply requirements (70 PJ over 10 years from 3Q2007)
— QGC/Pangaea Oil and Gas for the remainder of its gas supply requirements (74 PJ over 10 years from mid-2007)
— APA for transport on the RBP.

The gas sales agreements were therefore for the supply of approximately 144 PJ of gas over 10 years (notionally 14.4 PJ/year). All three agreements commenced in the second half of 2007 on the expiry of Incitec Pivot's previous gas supply contracts. Gas supply is therefore currently contracted to 2H2017.

It is not yet clear whether Incitec Pivot will secure new gas supply to continue operations beyond mid-2017. In May 2016 Incitec Pivot announced a 79 per cent decline in first-half net profit after high energy prices forced it to write down the value of its Gibson Island plant by $105.6 million[13]. Management at the time said the write-down reflected “ongoing challenges facing energy-intensive trade-exposed manufacturing in Australia” and flagged a need “to lower Gibson Island’s non-gas costs so we are globally competitive by the end of 2016”.[14] We have assumed for the Base Case forecast that the Gibson Island plant continues to operate at current levels throughout the next access arrangement period. However, there is clearly a degree of uncertainty regarding this assumption and the outcome is likely to have a binary effect on the demand for services on RBP. The closure scenario is reflected in the Low Case discussed in section 4.3.

For GPG we have calculated daily gas demand for each scheduled[15] gas-fired NEM-participant station located in southern Queensland based on modelled dispatch of each unit using ACIL Allen’s current Reference Case electricity market modelling. Gas consumption is calculated from the modelled hourly dispatch (GWh) by applying the heat rate and auxiliary energy requirement appropriate to each unit.

The two NEM-participant gas-fired power stations that are directly reliant on RBP are the Oakey open-cycle gas turbine (OCGT) power station, which runs on gas delivered via RBP with liquid fuel back-up from on-site storage, and the Swanbank E combined cycle gas turbine (CCGT) plant, which is fully reliant on gas supply via RBP. The outlook for these two stations is of key importance to the future demand for services on the RBP, and is therefore discussed in detail the following sections.

[11] Closure of the BP Bulwer Island refinery follows closures of ExxonMobil Port Stanvac (Adelaide, 2009); Shell Clyde (Sydney 2012) and Caltex Kurnell (Sydney 2014).
[12] “Gas agreements secure future of fertiliser plants”, Incitec Pivot ASX Release dated 6 September 2004.
[13] “IPL releases results for the half year to 31 March 2016”, Incitec Pivot Media Release dated 10 May 2016.
[14] Sydney Morning Herald, http://www.smh.com.au/business/incitec-pivots-net-profit-dives-79pc-on-gibson-island-plant-writedown-20160509-goqcgw.html
[15] “Scheduled” means that the plant is a participant in the NEM and is therefore centrally dispatched by AEMO.

4.1.1 Oakey Power Station

Oakey PS – Key metrics

Capacity — 282 MW[16]

Plant efficiency — 32.6%

Heat Rate — 11.04 GJ/MWh

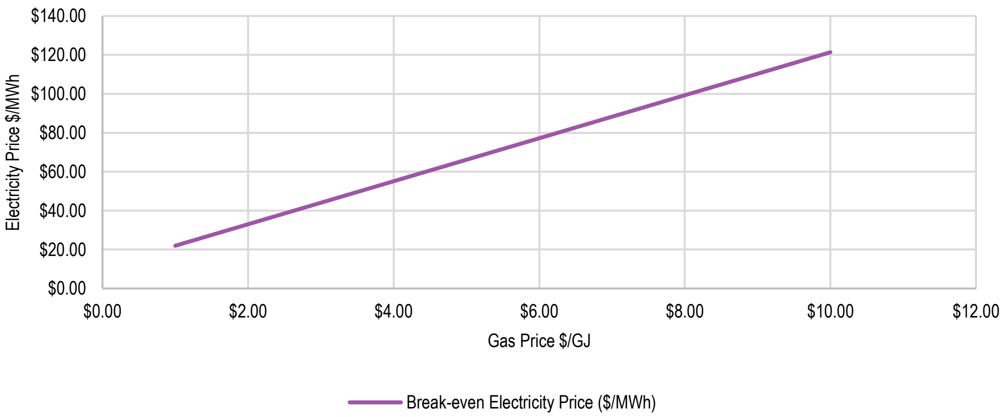
Variable Operating and Maintenance Cost — $10.93/MWh[17]

On this basis, the break-even prices of wholesale electricity (that is, the electricity price that would cover Oakey PS fuel and variable operating & maintenance costs) at different gas prices are as shown in **Figure 4.1**.

— A gas price of $4.00/GJ means that Oakey PS needs to achieve a wholesale electricity price of $55.10/MWh to cover short-run marginal costs.

— A gas price of $8.00/GJ means that Oakey PS needs to achieve a wholesale electricity price of $99.27/MWh to cover short-run marginal costs.

FIGURE 4.1 BREAK-EVEN ELECTRICITY PRICES AT DIFFERENT GAS PRICES



SOURCE: ACIL ALLEN ANALYSIS

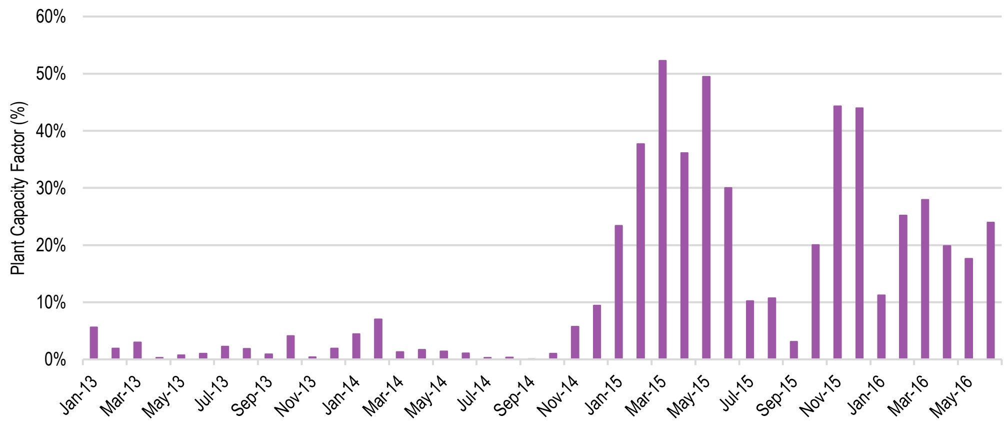
Historical dispatch of Oakey PS

Figure 4.2 shows the historical monthly average capacity factors (actual dispatch GWh/total GWh at 100% dispatch). Prior to December 2014, average capacity factor was about 2 per cent. From December 2014 to June 2016, average capacity factor was 22 per cent.

[16] 282 MW is the effective capacity according to AEMO (“Generation Information Queensland” April 2016), rather than the theoretical “nameplate” capacity of 332 MW listed on owner ERM’s website.

[17] $10.40/MWh in 2014 as set out in ACIL Allen 2014 “Fuel and Technology Cost Review Data” prepared for AEMO, June 2014, escalated annually at 2.5 per cent.

FIGURE 4.2 OAKEY PS HISTORICAL CAPACITY FACTOR (MONTHLY AVERAGES)



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

An important question is whether the change in dispatch pattern was driven by market conditions that are likely to persist in the future. To assess this we look at:

— To what extent was the level of dispatch over the period December 2014 to June 2015 an "economically rational" response to the gap between electricity and gas prices?

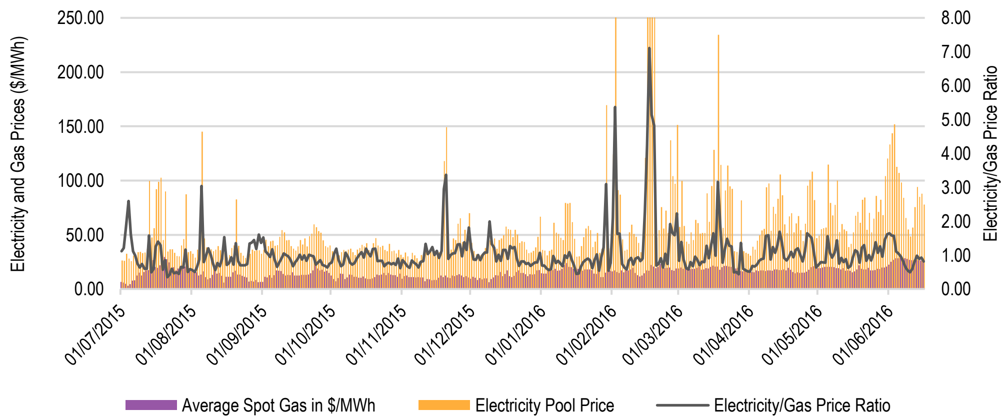
— To what extent was the level of dispatch over the period December 2014 to June 2015 driven by factors other than the gap between electricity and gas prices?

In order to determine whether dispatch was "economically rational" we first examine the relationship between electricity and gas prices.

Electricity Prices compared to Gas Prices

Figure 4.3 compares daily electricity and gas prices in southern Queensland over the period 1 July 2015 to 15 June 2016. The electricity/gas price ratio shows several peaks when open cycle gas-fired generation would have been profitable.

FIGURE 4.3 DAILY PRICE COMPARISON: ELECTRICITY VS GAS



Note: Electricity Price is average of half-hourly Queensland reference pool prices for the relevant day. Average Spot Gas Price is average of the ex-post price for the day in the Brisbane STTM and the Wallumbilla Hub (RBP).

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Because electricity prices are determined every half hour, the daily electricity prices in **Figure 4.3** represent the arithmetic average of the prices recorded by AEMO for each of the 48 individual half-hourly prices in that day. On the other hand, spot gas prices in the Brisbane Short Term Trading Market (STTM) and at the Wallumbilla Gas Supply Hub are set once per day. This is important because it means that electricity prices may be high enough to provide economic justification for generating during some half-hourly periods of the day, but not at other times.

Figure 4.4 shows, at half-hourly resolution, the periods when the difference between electricity prices and gas prices was large enough to allow profitable dispatch of Oakey PS. We refer to the difference between electricity prices and gas prices as the "electricity price differential or EP_Δ; it is sometimes referred to as the "spark spread". The EP_Δ values shown in **Figure 4.4** are calculated as follows:

$$EP_\Delta = P_e - (P_g \times 3.6 \div \varepsilon + VOM)$$

where P_e = price of electricity in \$/MWh

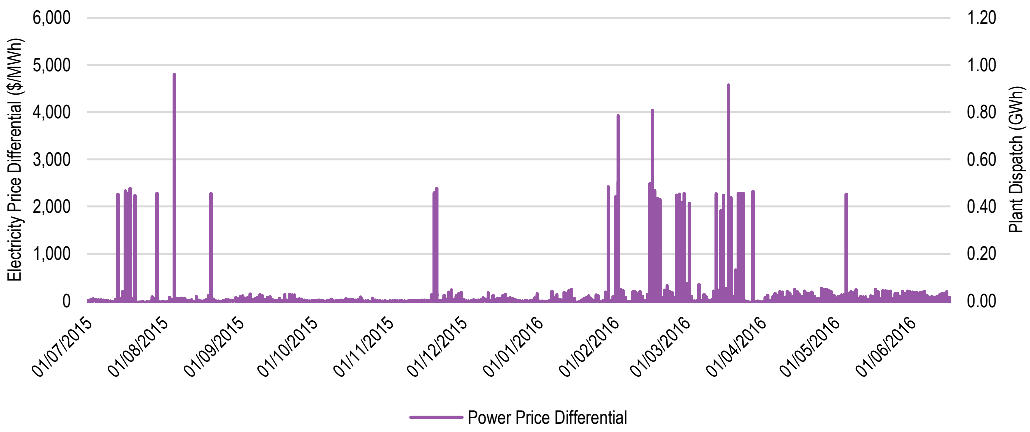
P_g = price of gas in \$/GJ

ε = thermal efficiency of Oakey PS (= 32.6%)

VOM = Variable Operating and Maintenance Cost in \$/MWh

Figure 4.4 shows only values of EP_Δ greater than zero. These effectively represent periods when electricity prices were high enough to enable Oakey PS to make a profit after recovering its Short-Run Marginal Cost of generation (SRMC, equal to fuel cost plus VOM). The heights of the purple columns in **Figure 4.4** reflect the size of the opportunity for profitable generation, with higher differentials representing greater profit opportunities.

FIGURE 4.4 POSITIVE ELECTRICITY PRICE DIFFERENTIALS, JULY 2015 – JUNE 2016



Note: Only positive price differentials are shown

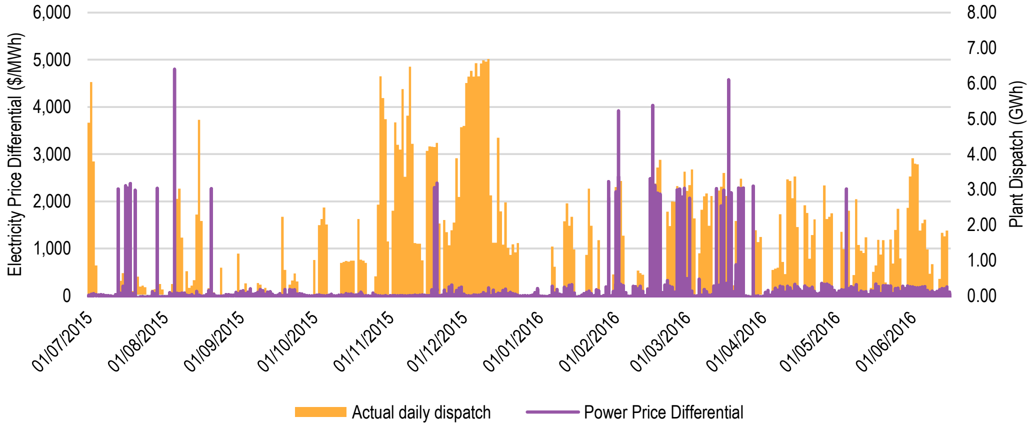
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Figure 4.5 superimposes the actual daily dispatch of Oakey Power Station (in GWh per day) on the EP_Δ values shown in **Figure 4.4**.

It can be seen that over the year 2015–16 there were many periods when Oakey PS ran at high levels despite the fact that the EP_Δ values were zero (or less than zero). There were some periods when the price data indicates that Oakey PS could have dispatched profitably but did not run. Similarly there were significant periods (for example, on numerous occasions over the period January–February 2016) when the station dispatched much more than would have been expected purely on the basis of the electricity–gas price relativities.

These observations suggest that factors other than the EP_Δ values influenced the levels of dispatch of Oakey PS at these times.

FIGURE 4.5 OAKEY PS ACTUAL DISPATCH COMPARED WITH POSITIVE ELECTRICITY PRICE DIFFERENTIALS, JULY 2015 – JUNE 2016

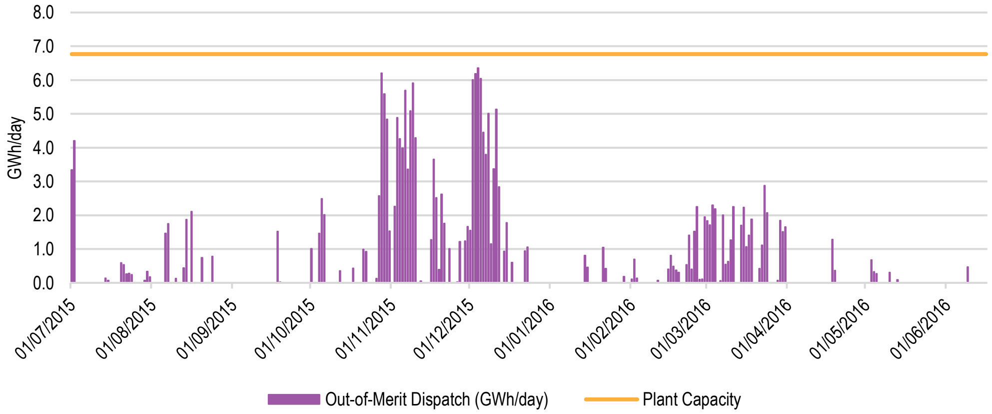


Note: Only positive price differentials are shown

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Figure 4.6 shows the extent of out-of-merit[18] dispatch of Oakey PS. The purple bars show the level of dispatch (GWh per day) at times when the EP_{Δ} values were zero or negative (in other words, at times when electricity prices were too low to cover the plant's SRMC). There were many days in late 2015 and early 2016 when the station dispatched at high levels, close to full plant capacity over the entire day, at times when the EP_{Δ} values were not high enough to cover SRMC.

FIGURE 4.6 OAKEY PS OUT-OF-MERIT DISPATCH FOR PERIOD 1 JULY 2015 TO 16 JUNE 2016



SOURCE: ACIL ALLEN ANALYSIS DRAWING ON AEMO DATA

Cause of Out-of-Merit Dispatch

There are a number of possible explanations for the out-of-merit dispatch seen in **Figure 4.6**:

— Oakey PS may have had access to low cost gas at these times (that is, lower prices than those reflected in the spot market prices). This could come about through provisions of gas sales contracts such as take-or-pay obligations, expiry of gas banking entitlements or other commercial arrangements. However, if the spot market valued these gas entitlements at the time more highly than the actual contract price, Oakey PS could have profited by selling the gas into the spot or short-term trading market rather than using the gas to generate at low implied gas values.

[18] The term "out-of-merit" is used here to refer to a situation in which a generator bids into the electricity market at prices that would not cover its short-run marginal costs if the gas it used was costed at full market price.

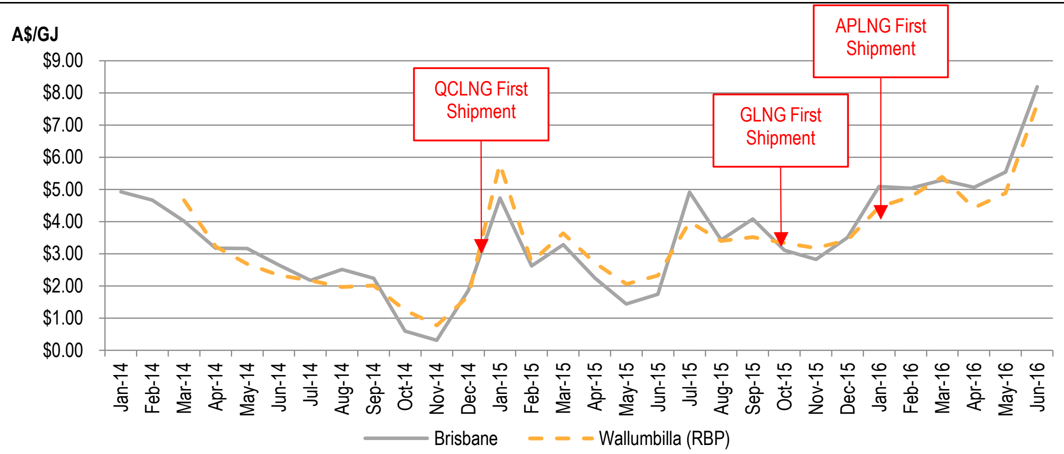
— Oakey PS may have had electricity market contracts (for example, hedge contracts) that obliged it to run. This is an unlikely explanation because when electricity/gas price differentials are low, wholesale electricity prices are low. Therefore at these times Oakey PS could meet its hedge contract obligations at lower cost by purchasing electricity from the wholesale market, rather than supplying electricity into the market at a cost higher than the wholesale price of electricity.

— A gas producer—most likely one of the LNG projects—may have provided Oakey PS with gas that was surplus to requirements at the time, at low or zero cost. In effect, the gas producer in such circumstances would have paid a "tolling fee" to the power station owner in order to get some return from gas that had to be produced but could not be stored or sold at the time. Such a situation could arise in the case of "ramp up" gas which is gas produced in advance of the start-up of the LNG facilities. The "ramp up" gas effect occurs because the CSG wells that provide most of the gas to the LNG plants are typically unable to achieve full production rates immediately on start-up. Instead they have to be brought into production ahead of LNG plant commissioning, building up to their maximum production rates over a period of several months as the CSG wells "dewater".

In our opinion, "ramp up" gas for the LNG plants provides the most likely explanation for the observed out-of-merit dispatch of Oakey PS. We think it is no coincidence that the high levels of out-of-merit dispatch over the period October 2015 to January 2016, and again in March–April 2016, occurred during periods immediately ahead of the commissioning of new LNG trains at Gladstone. GLNG Train 1 made its first LNG shipment in October 2015 and APLNG Train 1 its first shipment in January 2016. The first peak period of out-of-merit dispatch can therefore be explained by a short period of excess gas supply as the CSG production wells to supply these two new liquefaction trains were brought on line during the commissioning period. Similarly the second peak period in March–April 2016 corresponds with the commissioning period for GLNG Train 2 which received its first gas into the LNG plant in May 2016.

One question which arises is why, if the above explanation for the high levels of out-of-merit dispatch of Oakey PS seen during 2015–16 is correct, the same behaviour was not observed during the second half of 2014 immediately prior to commissioning of the first Gladstone LNG plant (QCLNG Train 1, which loaded its first shipment during December 2014). "Ramp-up" effects on gas prices were clearly apparent at that time, with both Brisbane STTM and Wallumbilla spot prices at historic low levels of around $1.00/GJ (**Figure 4.7**)—much lower than the spot prices during the periods of high Oakey PS dispatch in later 2015 and early 2016. Yet, as shown in **Figure 4.2**, Oakey PS achieved very low levels of dispatch—less than 1 per cent—at this time.

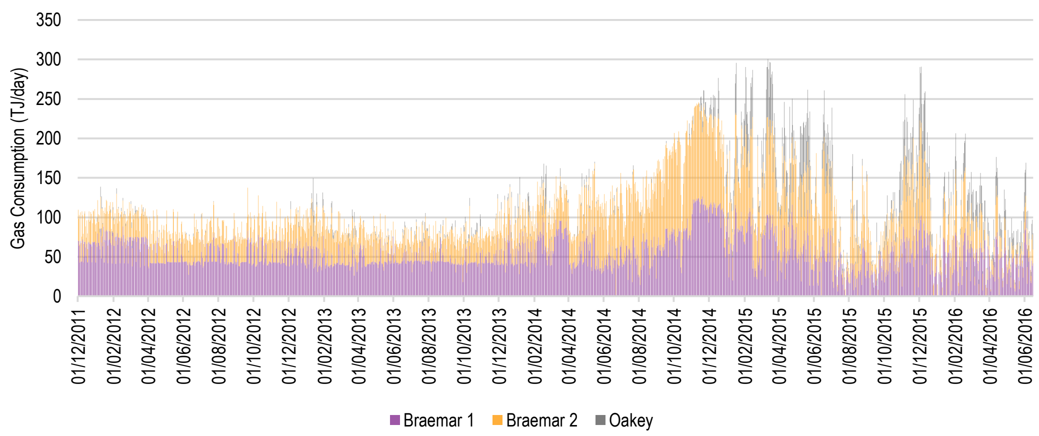
FIGURE 4.7 BRISBANE STTM AND WALLUMBILLA RBP SPOT PRICE HISTORY



SOURCE: ACIL ALLEN COMPILATION OF AEMO PRICE DATA. COMPANY MEDIA RELEASES ON LNG PROJECT START-UPS

The explanation is that during the second half of 2014 the ramp up gas produced ahead of commissioning of QCLNG Train 1 was used to drive abnormally high levels of generation at the Braemar 1 and 2 power stations, but not at Oakey PS. This is illustrated in **Figure 4.8** which shows gas consumption[19] for Braemar 1, Braemar 2 and Oakey PS over the period from January 2011 to June 2016. The fact that Oakey PS did not run at abnormal levels through the first ramp up period in the later part of 2014, while the Braemar units did, suggests that the consumption of ramp up gas in these stations was driven by commercial tolling agreements or similar arrangements between the generator and the LNG developer, rather than as a result of the generators opportunistically buying spot gas prices at low prices. This is an important observation because it suggests that the high running rates seen in southern Queensland gas-fired generating plants (including Oakey) in recent times are more likely to be transient commercial arrangements to accommodate LNG ramp up, rather than a response that can be expected whenever spot gas prices are low.

FIGURE 4.8 BRAEMAR–1, BRAEMAR–2 AND OAKEY PS, HISTORICAL GAS CONSUMPTION



Note: Gas consumption derived from AEMO data on plant dispatch

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Future dispatch of Oakey PS

If the high levels of out-of-merit dispatch of Oakey PS over the period late 2015 to mid-2016 are indeed related to the availability of excess gas supply in advance of commissioning of new LNG trains at Gladstone, then it would be reasonable to expect that such patterns of dispatch will be much less common in future. There may be some higher-than-usual dispatch of Oakey PS in the lead up to commissioning of APLNG Train 2 during the second half of 2016. However, once all six planned LNG trains at Gladstone are fully operational, excess gas production is likely to occur only as a result of unplanned LNG plant outages. To the extent that planned outages can be accommodated by placing excess gas into underground gas storage (Silver Springs, Roma, Cooper Basin), by use of line pack capacity in the large diameter export pipelines, or by commercial gas swap arrangements between the LNG project proponents, there will be no need to force gas into generators such as Oakey PS at times when electricity prices imply low gas values.

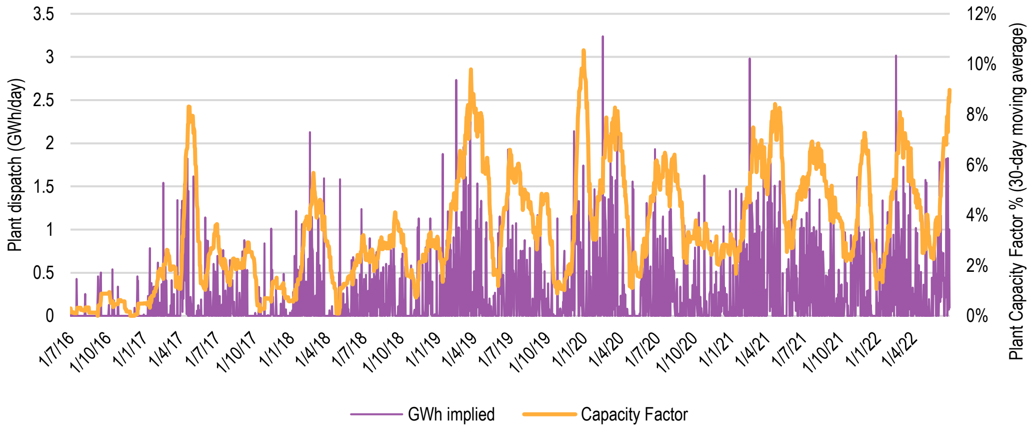
There will no doubt be times when Oakey PS and other southern Queensland gas-fired power stations will be able to take advantage of short-term availability of low-cost gas as the LNG plant operators manage day-to-day operational variations in their gas requirements. The operation of the Brisbane STTM and Wallumbilla Gas Supply Hub should facilitate the realisation of such opportunities. However they will be transient and largely unpredictable in terms of their extent and timing. In our opinion they are unlikely to provide a basis for booking firm capacity services on RBP.

Figure 4.9 shows the modelled future dispatch of Oakey PS based on ACIL Allen's current Reference Case electricity market assumptions. The modelled dispatch represents "economically efficient" levels of operation, with the station dispatching only when it is able to cover its SRMC. It does not include out-of-merit dispatch such as has been seen over the past year during the period of LNG ramp-up. On this basis we would expect, over the period of the next RBP access arrangement, to see Oakey PS operating at a capacity factor between 2 per cent and 10 per cent, averaging about 4 per cent. There

[19] Gas consumption has been calculated from actual levels of dispatch (GWh/day) for each plant, as recorded by AEMO public data.

will be occasional peak days when the station will generate at up to 3.25 GWh/day (drawing gas at up to 35 TJ/day) but these peak days will be infrequent.

FIGURE 4.9 MODELLED FUTURE DISPATCH OF OAKEY POWER STATION



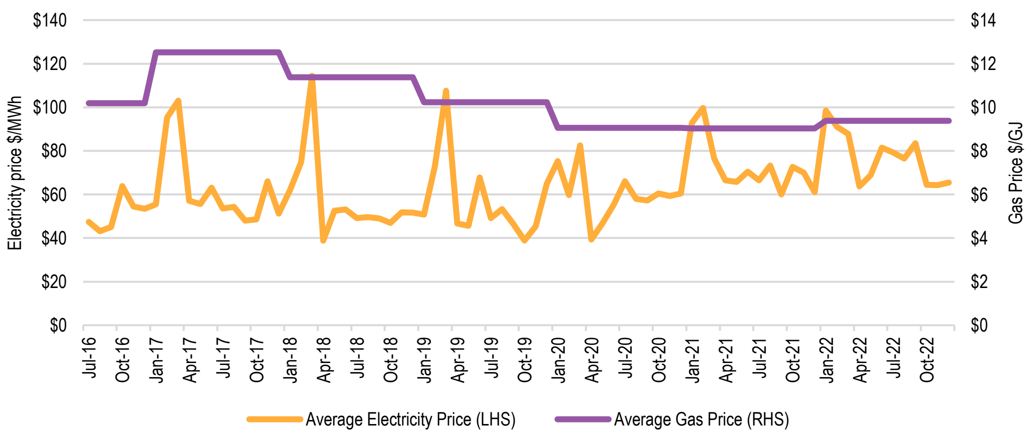
SOURCE: ACIL ALLEN ELECTRICITY MARKET MODELLING

4.1.2 Swanbank E Power Station

Swanbank E CCGT presents a particular challenge for the Base Case forecast of future demand for services on the RBP. As previously discussed (see section 3.2.4) Swanbank E was withdrawn from service on 1 December 2014 with the owner Stanwell Corporation announcing that it would sell its gas entitlements, rather than using them to generate electricity. At the time, Stanwell Corporation indicated that Swanbank E would remain off line “for up to three years”. This timing may have reflected the tenor of Stanwell’s existing gas supply arrangements, some of which we understand are due to expire in late 2017. However, the question of whether Swanbank E will be restarted at that time will depend to a large extent on whether or not Stanwell is able to negotiate new gas supply arrangements at a price that makes it economically viable to restart operations. ACIL Allen’s electricity market modelling suggests that this is unlikely.

Figure 4.10 show the gas prices (modelling inputs) and electricity prices (modelling outputs) over the next access arrangement period, under ACIL Allen’s current Reference Case electricity modelling assumptions.

FIGURE 4.10 MODELLED GAS AND ELECTRICITY PRICES OVER THE NEXT ACCESS ARRANGEMENT PERIOD

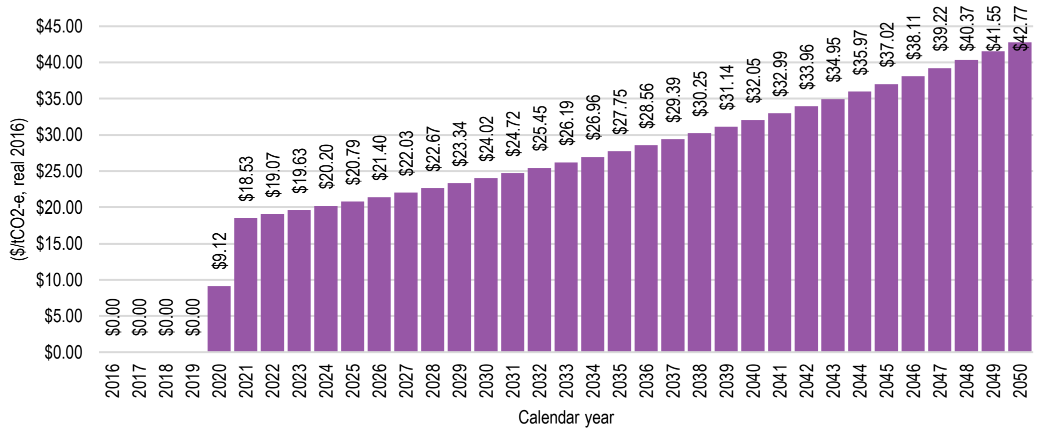


Note: The gas and electricity prices in this chart are shown in nominal dollars of the day.
SOURCE: ACIL ALLEN ELECTRICITY MARKET MODELLING

Our modelling assumptions include the reintroduction of explicit carbon pricing from mid-2020 at the levels shown in **Figure 4.11**. As shown in **Figure 4.10**, the reintroduction of carbon prices at these levels causes the lower bound of average wholesale electricity prices to rise from around $40/MWh to $60/MWh.

AEMO in its 2016 National Electricity Forecasting Report (NEFR) Methodology Paper makes no mention of carbon price assumptions. However a report prepared for AEMO by Jacobs as input to the 2016 NEFR forecast explicitly assumes the reintroduction of a carbon scheme from 2020 at $25/t CO2-e escalating linearly to $50/t CO2-e by 2030.[20] AEMO appears to have accepted the Jacobs assumption on the reintroduction of a carbon price, although it does not comment on the reasonableness of that assumption.

FIGURE 4.11 CARBON PRICE ASSUMPTIONS USED FOR ACIL ALLEN'S ELECTRICITY MARKET MODELLING



SOURCE: ACIL ALLEN CONSULTING

It is important to note that there is no current policy basis for assuming the reintroduction of a carbon price. The Australian Government has committed to reduce greenhouse gas emissions to 26–28 per cent below 2005 levels by 2030[21]. It proposes to achieve this target by implementing "a suite of Direct Action policies, including the $2.55 billion Emissions Reduction Fund". The government has announced that it will review the overall design of Australia's 2030 target policy framework in 2017–18, and there is an expectation that additional measures beyond the current Direct Action initiatives will be required to achieve the target. However the government's position remains that it is "committed to tackling climate change without a carbon tax or an emissions trading scheme that will hike up power bills for families, pensioners and businesses".[22]

The assumptions that we have made regarding carbon prices therefore do not reflect current government policy: they have been made for modelling purposes and to aid comparison between our results and those produced by AEMO. We make no comment on the reasonableness or otherwise of the assumption that carbon prices will be reintroduced—that will be a matter for Government to decide.

Modelling results

We have modelled the levels of dispatch that Swanbank E could expect to achieve, under a range of gas price assumptions, if it was to re-enter the market. The results are summarised in **Figure 4.12**. The purple columns in **Figure 4.12** show that, under the electricity, gas and carbon price assumptions

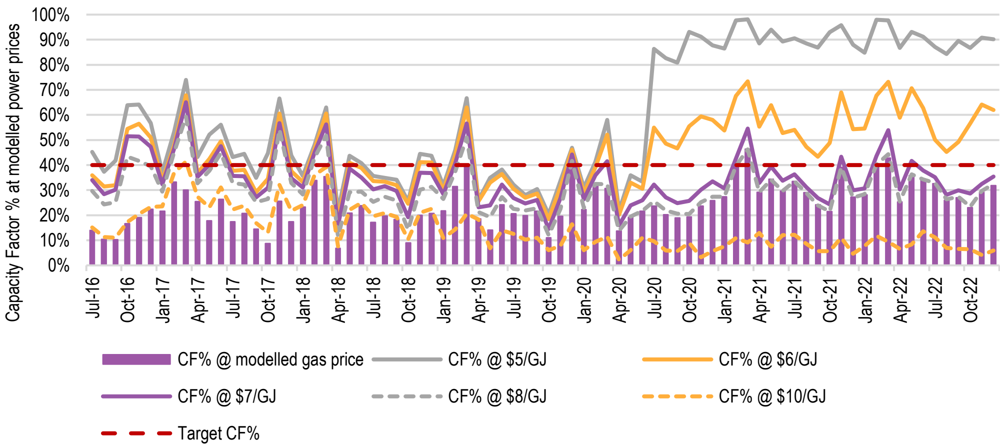
[20] Jacobs 2016: "Retail electricity price history and projections", dated 23rd May 2016, at p.28. Report available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/-/media/E32734E08CD54504B2A5F408FAAB1870.ashx

[21] "Australia's 2030 Emission Reduction Target", https://www.dpmc.gov.au/sites/default/files/publications/Summary%20Report%20Australias%202030%20Emission%20Reduction%20Target.pdf

[22] "Australia's 2030 emissions reduction target", Joint media release by The Hon Tony Abbott MP, Prime Minister; The Hon Julie Bishop MP, Minister for Foreign Affairs; The Hon Greg Hunt MP, Minister for the Environment. 11 August 2015

set out above, Swanbank E would achieve a modelled average capacity factor of 25 per cent over the period July 2017 to June 2022, with a maximum monthly average capacity factor of 46 per cent (March 2021). Prior to the assumed re-introduction of carbon pricing the modelled average capacity factor of Swanbank E is 22 per cent, rising to 30 per cent after carbon prices are re-introduced.

FIGURE 4.12 MODELLED CAPACITY FACTOR OF SWANBANK E UNDER DIFFERENT GAS PRICES



Note: CF% means Capacity Factor Per Cent which is equal to modelled operating hours/total available operating hours at the nominated gas prices. The gas prices are expressed in real 2016 terms.

SOURCE: ACIL ALLEN CONSULTING ANALYSIS

The technical design of Swanbank E is not well-suited to running at low capacity factors; our understanding is that for both technical and commercial reasons it is unlikely that Swanbank E could be operated on a sustained basis at capacity factors less than about 40 per cent. Hence we conclude that, under the gas price assumptions used in ACIL Allen's current electricity Reference Case, Swanbank E would not achieve levels of dispatch high enough to justify a return to service during the next access arrangement period. **Figure 4.12** also shows the capacity factors that Swanbank E could be expected to achieve under a range of different gas prices (from $5/GJ up to $10/GJ), assuming that the modelled electricity prices shown in **Figure 4.10** remain the same for all cases.[23] The step-change increases in Swanbank E capacity factor from July 2020 at lower gas prices (the yellow and grey lines) relate to the assumed reintroduction of carbon pricing at this time. Carbon prices have the effect of increasing the competitiveness of Swanbank E relative to some less efficient and more carbon-intensive coal-fired plant.

The results show that at gas prices of $7/GJ or higher, Swanbank E would not achieve a target capacity factor of 40 per cent on a sustained basis at any time over the next access arrangement period, even with carbon prices at the levels assumed. At gas prices of $6/GJ or lower, the target capacity factor would be regularly exceeded from mid-2020, indicating a possible return to service *if a carbon price is introduced at this time*. In the absence of a carbon price, capacity factors would continue at around the pre-2020 modelled levels.

We think it is unlikely that gas will be available under firm supply contracts for a delivered price of $6/GJ or less. This view is supported by analysis undertaken by CORE Energy for AEMO in 2015.[24] CORE presented forecasts of gas prices for power generation in the eastern states. In relation to Swanbank E, CORE stated that "Swanbank E is assumed to close after 2015, therefore CORE has not provided a price forecast for this power station".[25] However, for other GPG sites in Southern Queensland (Darling Downs, Braemar 1 & 2 and Condamine) CORE estimated that delivered prices would increase to between $8.00/GJ and $8.50/GJ by 2017–18 under their Base Case assumptions. The corresponding ranges for CORE's Low and High Cases were $7.50–$7.90/GJ and $9.50–$10.20/GJ respectively.

[23] The re-entry of Swanbank E would in fact be likely to result in lower modelled electricity prices (more supply, same demand). As a result, the levels of economic dispatch of Swanbank E would be lower than shown in this analysis.
[24] CORE Energy Group (2015): *AEMO Gas Price Consultancy*, August 2015.
[25] CORE Energy Group (2015), p.21.

Future dispatch of Swanbank E

Based on this analysis, we conclude that Swanbank E is unlikely to return to service during the next access arrangement period unless two conditions are fulfilled:

a) a carbon price is reintroduced, at a meaningful level of, say, \$20/t CO_2e; and

b) long term gas supply is available at a delivered price of \$6/GJ or less.

With regard to carbon prices, the modelling shows clearly that Swanbank E is unlikely to achieve viable levels of dispatch in the absence of an explicit carbon pricing mechanism. This is so even if gas supply can be secured at prices well below those modelled for this report. As previously discussed, there is no current policy basis for assuming that a carbon price will be reintroduced. A conclusion that Swanbank E will return to service based on reintroduction of a carbon pricing mechanism would therefore be highly speculative.

With regard to gas prices, there is good evidence to support the view that Stanwell is unlikely to be able to secure firm, long term gas supply for Swanbank E post-2017 at a delivered price of \$6/GJ or less.

On this basis we find no market justification for a return to service of the Swanbank E power station during the next access arrangement period.

This represents a binary outcome for the market forecast: if Swanbank E does restart and achieves dispatch comparable to its historic performance, it will consume around 15 PJ/a at an average rate of about 41 TJ/day, peaking at 60–70 TJ/day. If, as we consider more likely, it does not resume operation before 2022 then Swanbank E will not require any services on RBP during the next access arrangement period. We have attempted to reflect the binary nature of this outcome by excluding Swanbank E load from the Base Case and Low Case forecasts, but including Swanbank E load at 41 TJ/day average, 60 TJ/day peak from the beginning of 2018 under the High Case forecast.

4.1.3 Other gas-fired power stations

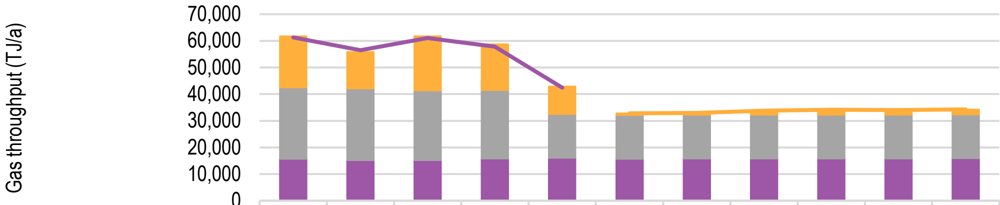
Other gas-fired stations on the Darling Downs may use some gas from RBP, but have access to gas supply delivered via other pipelines. The evidence available to us (AEMO data on plant dispatch; APA confidential meter data) indicates to us that the Darling Downs CCGT (Origin Energy) and Condamine CCGT (QGC) have not, in the past, used any gas delivered via RBP, and that the Braemar Power Stations have used RBP for between 6 per cent and 10 per cent of their total gas supply. For purposes of the Base Case forecast, we therefore assume that the Braemar Power Stations will, in future, draw on RBP for 8 per cent of their combined gas requirements.

4.2 Base Case Forecast

4.2.1 Annual east-bound throughput

Figure 4.13 shows the Base Case forecast for annual east-bound gas throughput on the RBP.

FIGURE 4.13 BASE CASE FORECAST FOR RBP ANNUAL EAST-BOUND THROUGHPUT



	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Powergen	19,274	13,793	20,469	17,331	10,386	655	787	1,586	1,862	1,789	1,973
Total Large Industrial	26,807	26,923	26,186	25,696	16,450	16,450	16,450	16,450	16,450	16,450	16,450
Total Retail	15,675	15,187	15,168	15,756	16,073	15,703	15,733	15,762	15,791	15,821	15,850
Historical Actual Flow	61,290	56,537	61,120	57,776	42,448						
Forecast Annual Flow						32,809	32,969	33,798	34,104	34,060	34,273

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL ANNUAL THROUGHPUT DERIVED FROM AEMO DATA

The forecast sees total Retail annual demand growing modestly from 15,733 to 15,850 TJ/a over the forecast period 2017–18 to 2021–22.

The total for Large Industrial Customers fell to about 16,450 TJ/a in 2015–16 (reflecting a full year of closure of the BP Bulwer Island refinery and co-generation plant) and is expected to remain at this level throughout the next access arrangement period. This assumes that the Incitec Pivot Gibson Island fertiliser plant and other large industrial loads in the Port of Brisbane and Darling Downs areas continue to operate at around current levels. We are not aware of any plans for new Large Industrial loads that would use the RBP. In this regard, it is worth noting that AEMO in its most recent National Gas Forecasting Report expects total industrial demand in Queensland, under Mid Scenario assumptions, to decline at an average 3.8 per cent per year, from 130.7 to 108.2 PJ/a, over the period 2015 to 2020. Even under its High Scenario assumptions, AEMO expects industrial gas use in Queensland to decline at an average 0.1 per cent per year to 2020.[26] We expect that most of this contraction will occur in the Gladstone (non-LNG) and Townsville areas.

Supply to GPG shows a dramatic reduction in annual gas demand, reflecting a return to normal merit order dispatch of open-cycle gas fired plant after several years of operation at considerably higher levels. As discussed in section 2.4, a number of factors contributed to these outcomes, including the (now discontinued) Queensland Government policy which mandated minimum levels of gas-fired generation; CSG operators needing to continuously produce CSG fields in order to achieve reserves certification; and excess gas production associated with ramp-up of CSG fields in advance of LNG plant commissioning. The levels of forecast GPG consumption reflect the following assumptions:

— Oakey PS operates at efficient levels as indicated by ACIL Allen's Reference Case electricity market modelling. These are generally consistent with pre-2014 historical dispatch levels, and are much lower than the actual 2014 and 2015 dispatch levels which were driven by supply of excess CSG ramp-up gas.

— Swanbank E does not return to service during the next access arrangement period. As discussed in section 4.1.2, ACIL Allen's electricity market modelling indicates that, over the next access arrangement period, Swanbank E would not achieve high enough levels of dispatch to justify a return to service.

— Total annual gas requirements for the two Braemar OCGT plants are determined from ACIL Allen's detailed electricity market modelling which allows calculation of daily fuel requirements for each

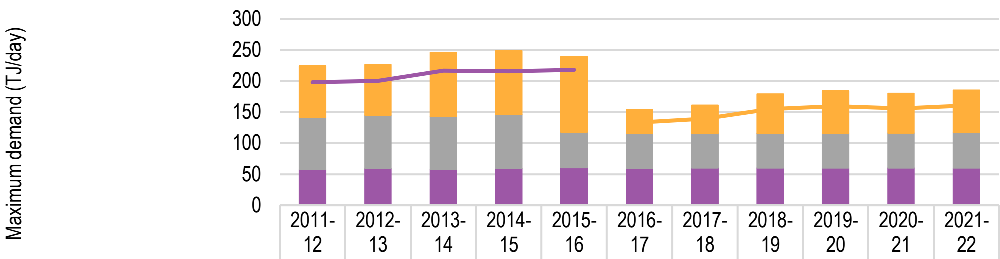
[26] AEMO National Gas Forecasting Report for Eastern and South-eastern Australia, 2015. Revised version published March 2016.

generation unit. The Braemar power stations are assumed to take 8 per cent of their annual gas requirements from the RBP, consistent with historical metered performance over the period 2011–12 to 2015–16.

4.2.2 Peak demand for east-bound throughput

Figure 4.14 shows historical and forecast peak demand for east-bound throughput on RBP, under Base Case assumptions.

FIGURE 4.14 BASE CASE FORECAST FOR RBP EAST-BOUND PEAK DAY FLOW



	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Powergen	83.0	81.6	102.7	102.4	121.5	38.2	45.1	63.1	68.1	64.0	68.2
Total Large Industrial	84.0	86.0	85.4	87.2	57.3	55.9	55.9	55.9	55.9	55.9	56.9
Total Retail	57.5	58.9	57.7	58.9	60.4	59.8	59.9	60.0	59.9	60.2	60.3
Historical System Peak	198.0	200.2	216.6	215.5	217.9						
Forecast aggregate peak						133.3	139.3	154.9	159.3	156.0	160.5

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL DAILY THROUGHPUT DERIVED FROM AEMO DATA

The columns in **Figure 4.14** represent the historical and forecast peak demand levels for each of the three different customer groups (retail, industrial and powergen), not the contribution of these groups to demand on the system peak day (which is discussed in section 3.2.1). We have done this because, in order to forecast peak demand we need to consider how peak demand in each customer sector is likely to change over time. However, the peak demand levels for different customer sectors normally fall on different days. For example, peak demand in the retail sector falls in winter, but peak demand in the powergen sector normally falls in summer. As a result, adding together the peaks for each sector produces totals that are higher than the actual total system peaks. Over the past five years the total system peaks (purple line in **Figure 4.14**) have ranged between 198 and 218 TJ/day. However, the sum of the peaks for each customer sector have generally been around 10 to 15 per cent higher, ranging between 225 and 250 TJ/day.

When we add together the forecast levels of peak demand in each of the three customer groups, we therefore need to discount the total similarly in order to derive a forecast for the total system peak.

The historical peak flow levels (purple line in **Figure 4.14**) provide a close approximation to levels of firm contract capacity on RBP. This implies that some of the historical individual sector peak deliveries were achieved by accessing non-firm (as-available or interruptible) services. As discussed in section 4.6 the level of future firm capacity bookings will be dependent on the contracting strategies of gas shippers, which may in turn be influenced by levels of spare capacity in the system and user expectations regarding the likelihood of non-firm services being available when they require them.

The forecasts for the three customer groups have been derived as follows:

— For the **total retail load**, peak day demand was determined by grossing up the forecast average daily throughput by the historic load factor for the retail delivery points which, over the period 2011–12 to 2015–16, was found to lie within a tight range of 71 to 73 per cent (average 72 per cent).

— For the **large industrial loads**, peak day demand was determined as the average of the peak demand for large industrial delivery points over the period 2011–12 to 2015–16, with the peak for the BP Bulwer Island site reduced to zero from mid-2015.

— For **gas-fired power generation** (GPG) the metered peak flows for the period 2011–12 to 2015–16 represent the sum of the actual peaks for the relevant delivery points determined from meter data.

From 2016–17 on the GPG peak flows represent the modelled year-on-year peak day flows for Oakey PS and Swanbank E, plus 20 per cent of the modelled year-on-year peak day flows for the Braemar 1 & 2 power stations. The 20 per cent factor is close to the historical proportion of Braemar peak demand serviced by RBP which, over the period 2011–12 to 2015–16 averaged 21 per cent based on a comparison of total peak flows for these stations with the relevant RBP metering point data.

Also plotted on **Figure 4.14** is the observed historical east-bound peak flow data for RBP as recorded in the AEMO Actual Flow data and APA meter data. The observed peak flow over the period 2011–12 to 2015–16 ranged between 87 per cent and 91 per cent (average 89 per cent) of the sum total of the retail, large industrial and power generation peaks. As noted above, adding together the peak demand for the three different customer classes overstates the total system peak demand because the demand peaks for the different classes are not usually coincident.

Taking into account a diversification factor of 89 per cent (equal to the average over the period 2011–12 to 2015–16) the future system aggregate east-bound peak demand under the Base Case assumptions ranges between 133 and 161 TJ/day over the forecast period 2017–18 to 2021–22, as represented by the yellow line in **Figure 4.14**.

4.3 Low Case Forecast

The Low Case Forecast is designed to illustrate the downside risk for RBP east-bound throughput during the next access arrangement period as a result of uncertainty regarding roll-over of large industrial contracts and the level of utilisation of RBP services for gas-fired generation.

The Low Case Forecast adopts the same assumptions as the Base Case except that:

— Incitec Pivot is assumed not to secure a new competitive gas supply contract to replace its current contract which expires late 2017. Accordingly the Incitec Pivot Gibson Island plant is assumed to close at the end of 2017.

— It is assumed that the Braemar Power Stations (which historically have obtained around 20 per cent of their peak gas supply requirements from the RBP) will source 10 per cent of their peak gas supply requirements from RBP and 8 per cent of annual gas supply from RBP (the Base Case assumes 20 per cent of Braemar peak requirement and 8 per cent of annual gas supply sourced from RBP).

4.3.1 Annual east-bound throughput: Low Case

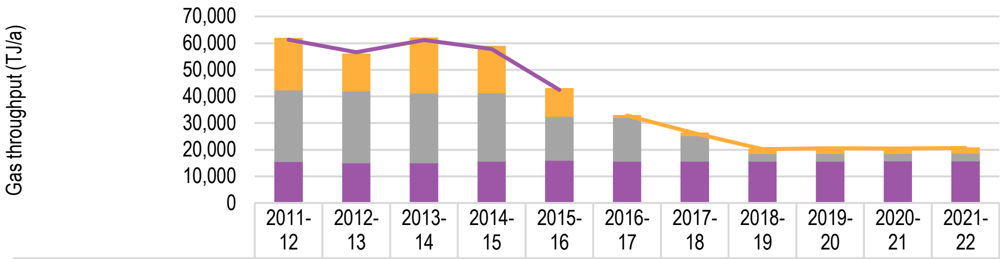
Figure 4.15 shows the Low Case forecast for annual gas throughput on the RBP.

The forecast sees total retail annual demand unchanged from the Base Case. The total for Large Industrial Customers falls steeply to 2,850 TJ/a in 2018 following the assumed closure of the Incitec Pivot Gibson Island fertiliser plant.

Other large industrial loads in the Port of Brisbane and Darling Downs areas continue to operate at current levels.

Supply to GPG is the same as for the Base Case assumptions.

FIGURE 4.15 LOW CASE FORECAST FOR RBP ANNUAL EAST-BOUND THROUGHPUT



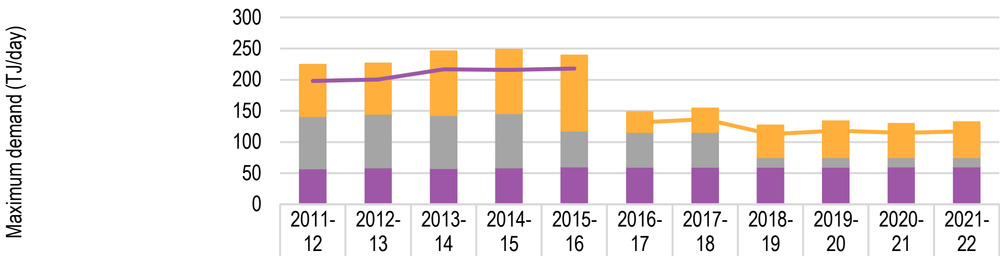
	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Powergen	19,274	13,793	20,469	17,331	10,386	655	787	1,586	1,862	1,789	1,973
Total Large Industrial	26,807	26,923	26,186	25,696	16,450	16,450	9,650	2,850	2,850	2,850	2,850
Total Retail	15,675	15,187	15,168	15,756	16,073	15,703	15,733	15,762	15,791	15,821	15,850
Historical Actual Flow	61,290	56,537	61,120	57,776	42,448						
Forecast Annual Flow						32,809	26,169	20,198	20,504	20,460	20,673

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL ANNUAL THROUGHPUT DERIVED FROM AEMO DATA

4.3.2 Peak demand for east-bound throughput: Low Case

Figure 4.16 shows the forecast for peak day east-bound throughput on RBP, calculated by adding together the peak demand for the three different customer classes under the Low Case assumptions. Total retail load peak day demand is unchanged from the Base Case assumptions. For the large industrial loads, peak day demand falls from 56 TJ/day to 15 TJ/day in 2018–19 following the assumed closure of the Incitec Pivot Gibson Island plant. For GPG peak flows are up to 11 TJ/day lower than for the Base Case.

FIGURE 4.16 LOW CASE FORECAST FOR RBP EAST-BOUND PEAK DAY FLOW



	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Powergen	83.0	81.6	102.7	102.4	121.5	32.8	38.5	52.1	58.4	54.5	56.8
Total Large Industrial	84.0	86.0	85.4	87.2	57.3	55.9	55.9	15.1	15.1	15.1	15.1
Total Retail	57.5	58.9	57.7	58.9	60.4	59.8	59.9	60.0	59.9	60.2	60.3
Historical Peak	198.0	200.2	216.6	215.5	217.9						
Forecast aggregate peak						131.5	136.6	112.6	118.1	114.8	117.0

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL DAILY THROUGHPUT DERIVED FROM AEMO DATA

Also plotted on **Figure 4.16** is the observed historical peak flow data for RBP as recorded in the AEMO Actual Flow and APA meter data. Taking into account an assumed diversification factor of 89 per cent (equal to the historical average) the future system aggregate peak demand under the Low Case assumptions ranges between 113 and 137 TJ/day over the forecast period 2017–18 to 2021–22, as shown by the yellow line in **Figure 4.16**.

4.4 High Case Forecast

The High Case Forecast is designed to illustrate the upside opportunity for RBP east-bound throughput during the next access arrangement period as a result of uncertainty regarding the timing of return to service of the Swanbank E CCGT power station.

The High Case Forecast adopts the same assumptions as the Base Case except that:

— Swanbank E is assumed to return to service from 1 January 2018, at a level of utilisation equal to the average of that observed over the period 2010–11 to 2014–15 (around 15.2 PJ/a)

— It is assumed that the Braemar Power Stations (which historically have obtained around 20 per cent of their peak gas supply requirements from the RBP) will source 40 per cent of their peak gas supply requirements and 8 per cent of annual gas supply from RBP (the Base Case assumes 20 per cent of Braemar peak requirement and 8 per cent of annual gas supply sourced from RBP).

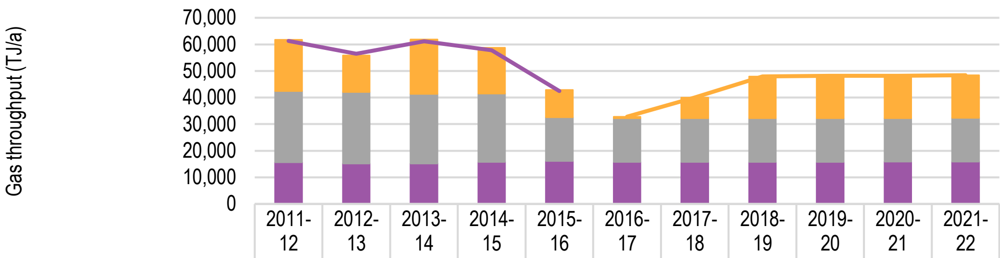
4.4.1 Annual east-bound throughput: High Case

Figure 4.17 shows the High Case forecast for annual east-bound gas throughput on the RBP.

The forecast sees total Retail and Large Industrial Customers demand unchanged from the Base Case.

Compared to the Base Case, supply to GPG shows an increase of 14,140 TJ/a from January 2018 on as a result of the early return to service of the Swanbank E power station.

FIGURE 4.17 HIGH CASE FORECAST FOR RBP ANNUAL EAST-BOUND THROUGHPUT



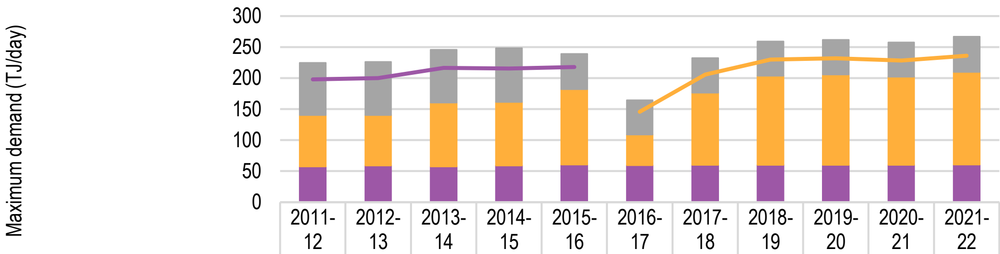
	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Powergen	19,274	13,793	20,469	17,331	10,386	655	7,857	15,727	16,003	15,930	16,113
Total Large Industrial	26,807	26,923	26,186	25,696	16,450	16,450	16,450	16,450	16,450	16,450	16,450
Total Retail	15,675	15,187	15,168	15,756	16,073	15,703	15,733	15,762	15,791	15,821	15,850
Historical Actual Flow	61,290	56,537	61,120	57,776	42,448						
Forecast Annual Flow						32,809	40,040	47,939	48,244	48,201	48,413

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL ANNUAL THROUGHPUT DERIVED FROM AEMO DATA

4.4.2 Peak demand for east-bound throughput: High Case

Figure 4.18 shows the forecast for east-bound peak day throughput on RBP, calculated by adding together the peak demand for the three different customer classes under the High Case assumptions.

FIGURE 4.18 HIGH CASE FORECAST FOR RBP EAST-BOUND PEAK DAY FLOW



	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total Large Industrial	84.0	86.0	85.4	87.2	57.3	55.9	55.9	55.9	55.9	55.9	56.9
Total Powergen	83.0	81.6	102.7	102.4	121.5	49.0	116.7	143.6	146.0	141.8	149.5
Total Retail	57.5	58.9	57.7	58.9	60.4	59.8	59.9	60.0	59.9	60.2	60.3
Historical Peak	198.0	200.2	216.6	215.5	217.9						
Forecast aggregate peak						145.8	205.8	229.7	231.8	228.3	236.1

SOURCE: ACIL ALLEN ANALYSIS; HISTORICAL DAILY THROUGHPUT DERIVED FROM AEMO DATA

Total peak day demand for both retail loads and large industrial loads are unchanged from the Base Case assumptions. For GPG peak flows are up to 82 TJ/day higher than for the Base Case. 59 TJ/day of this increase is a result of the early return to service of the Swanbank E power station. Peak deliveries to the Braemar power stations increase by up to 23 TJ/day.

Also plotted on **Figure 4.18** is the observed historical peak flow data for RBP as recorded in the AEMO Actual Flow data. Taking into account an assumed diversification factor of 89 per cent (equal to the historical average) the future system aggregate peak demand under the High Case assumptions ranges between 146 and 236 TJ/day over the forecast period 2017–18 to 2021–22, as shown by the yellow line in **Figure 4.18**.

4.5 Risk mitigation strategies

It is worth considering whether there may be strategies available to APA to avoid a Low Case outcome and to boost the chances of achieving a High Case outcome. Could the pipeline service provider do anything to encourage an early return to service of the Swanbank E power station, or to reduce the risk of losing the Incitec Pivot load? There may be opportunities on both fronts, but they are necessarily limited in an environment where the cost of pipeline services represents a relatively small (and declining) part of the total delivered cost of gas.

In order to improve the chances of retaining the Gibson Island load, APA could look to offer Incitec Pivot a “prudent discount” on pipeline tariffs, on the basis that Gibson Island represents the largest load on the RBP (about 25 per cent of total throughput during the current access arrangement period) and its loss would therefore be likely to result in significant increases in the cost of transport for other users of the pipeline. However, the scope for discounting is relatively limited, given that the current Reference Tariff on the RBP is under $0.70/GJ (combined capacity reservation and throughput charge). The future for the Gibson Island facility will be determined much more by whether or not Incitec Pivot is able to negotiate replacement gas supply at affordable prices after the expiry of current contracts in 2017. If, as has been widely anticipated, the wholesale price of gas ex-plant under long-term contracts doubles, or even triples, following the commissioning of the Gladstone LNG plants (from $3 to $4/GJ to somewhere in the range $6 to $9/GJ), APA’s ability to influence Incitec Pivot’s delivered cost of gas supply to Gibson Island through discounting of tariffs will be very limited.

A lower cost of fuel could also support an early return to service of Swanbank E, which prior to its shutdown accounted for about 20 per cent of annual throughput and about 30 per cent of peak demand on the RBP. However, once again the ability of the pipeline service provider to influence the decision to return Swanbank E to service by offering “prudent discounts” is relatively limited. Swanbank E is a combined cycle gas turbine (CCGT) generator with a design that requires it to operate at relatively high capacity factors: it is not suitable for peaking service. Like other CCGT plants, Swanbank E’s ability to achieve high capacity factors regularly is dependent on its short-run marginal cost (SRMC) of generation, which in turn is determined primarily by its cost of fuel. The decision to mothball Swanbank E was not an indication that its fuel costs were too high. It was a decision made in recognition of the fact that, in a highly competitive electricity market with low average wholesale prices, Stanwell was able to make more money by on-selling its Swanbank E gas supply entitlements rather than using the gas to generate electricity.

When Swanbank E’s main gas supply contracts expire in late 2017, the question of whether or not a return to service is economically justified will come down to whether the market environment at the time will allow the plant to achieve its required levels of operational dispatch (around 40 per cent minimum) while covering its SRMC. This will depend on a) the plant’s average fuel cost, and b) the wholesale electricity price outlook at the time. Re-introduction of an explicit carbon price would also improve the chances of Swanbank E coming back on line, but is not part of the current government’s greenhouse gas abatement plans.

APA cannot influence the wholesale electricity price, but it can to some degree influence the delivered cost of fuel to Swanbank E. As in the case of Incitec Pivot at Gibson Island, the scope for reducing fuel costs by offering discounted tariffs is relatively limited. There may be some scope to work with Stanwell to develop transportation services that more efficiently reflect an optimal operating regime for the CCGT station. This could potentially benefit the economics of generation by reducing the total cost of transportation and/or by linking pipeline charges to plant performance (which would effectively mean that APA would be taking on some electricity market risk). However, the economics of generation at Swanbank E will be much more sensitive to wholesale electricity prices, gas commodity costs and carbon policy; changing the quantum or profile of pipeline transport costs is unlikely to be a significant determinant of the timing of the re-start decision.

Ultimately the pipeline service provider has limited opportunity to influence the commercial position of these key customers whose operational outlook will be driven primarily by factors other than gas transportation charges.

4.6 Implications for future RBP services

As discussed in section 4.2.2, under the Base Case assumptions the peak demand level (which in recent years has corresponded fairly closely with the level of firm contracted capacity in the RBP) is expected to drop by around 65 TJ/day, from an average 215 TJ/day to around 150 TJ/day. This decrease in peak demand can be attributed to the loss of Swanbank E (about 57 TJ/day peak) from mid-way through 2014–15 and the BP Bulwer Island load (about 35 TJ/day peak) from the beginning of 2015–16, offset to some extent by increased utilisation of other gas-fired generators in southern Queensland. The drop in peak load was not apparent during 2015–16 because of the very high levels of dispatch of other gas-fired generators, driven by the availability of excess ramp-up CSG during the commissioning of the Gladstone LNG projects. Much of that peak demand was met by accessing non-firm (as available and interruptible) services.

The loss of the BP Bulwer Island load (permanently) and the Swanbank E load (likely in our view to remain off line until after 2021-22) means that the current physical capacity of the RBP (216 TJ/day) is likely to be less heavily utilised than in the past. This potentially has implications for the future contracting strategies of RBP shippers. The firm service rate for the RBP is lower than the current negotiated “as available” and interruptible rates. However firm service is paid for on the basis of reserved capacity (GJ of capacity per day) rather than physical throughput (GJ actually shipped) which is the charging basis for non-firm services. For a “peaky” load such as an OCGT generating plant that runs only at times of high electricity demand— only a few per cent of the hours in a year— the effective cost of firm service *per GJ of gas delivered* can be very high.[27]

For such users, an “as available” or interruptible service is potentially cheaper than firm service, but in a pipeline with high levels of peak utilisation is less reliable. In a heavily utilised pipeline there is a high risk that the service will not be available on system peak days—precisely when it is most needed. For a gas-fired generator this could mean foregoing revenue by not being able to generate at times when electricity prices are high, or facing higher costs by having to switch to liquid fuel supply (which is an option for some, but not all, OCGT plant). Peaking generators therefore tend to rely on a mix of firm and non-firm service. Firm service rights entitle the holder to nominate for day-ahead “as available” service, which has a higher priority and is therefore more reliable than interruptible service.

The lower levels of peak capacity utilisation that we are forecasting for the RBP mean that OCGT plant operators will in future be more confident that non-firm services will be available when needed. In other words, the risk of non-firm service being unavailable when needed will be lower. It would therefore be reasonable to expect that, all else being equal, OCGT operators will look to reduce their total cost of gas transportation by booking less firm service (indeed, potentially none) and relying on more non-firm service.

Similar considerations apply, but to a lesser extent, for gas retailers. As discussed in section 3.2.2, the southeast Queensland retail gas market has a summer load factor of around 70 per cent (80 to 85 per cent in winter). Because retailers require a high level of confidence in their ability to meet customer supply obligations, they would normally be expected to cover most, if not all, of their peak supply requirement with firm capacity entitlements. However, this again depends on the risk associated with non-firm services. If there is a large amount of spare capacity in the pipeline system and the risk of non-firm services being interrupted is very low, even on system peak days, there will be an incentive for retailers to book less firm capacity and more non-firm capacity. For example, retailers may choose

[27] For example, an OCGT plant that pays $0.50/GJ for firm capacity service and runs for 5 per cent of the total hours in a year effectively pays $10/GJ for each unit of gas *actually drawn* from the system.

to reserve sufficient firm capacity to meet the summer demand, to ensure supply on days when capacity could be demanded by electricity generators. They could then meet their higher winter demands by supplementing their firm capacity with As-Available capacity, during periods when it is less likely that electricity generators will be competing for that capacity.

The forecast lower peak utilisation rate for the RBP is therefore likely to result in a shift in the service mix on the pipeline, with less demand for firm service and more demand for non-firm services. However, it is not possible to say just how much impact this will have on future levels of firm capacity booking in the RBP, because each shipper will adopt a commercial contacting strategy that reflects their individual circumstances. Other relevant considerations will include:

— the relative levels of charges for firm and non-firm services
— the extent to which firm service entitlements are a pre-requisite for non-firm services
— the perceived risk that firm capacity in the RBP will be reduced in the future.

5 WALLUMBILLA GAS SUPPLY HUB: IMPLICATIONS FOR SERVICES ON THE PIPELINE

The Wallumbilla Gas Supply Hub (WGSH) is an exchange for the wholesale trading of natural gas. The WGSH is operated by AEMO. It commenced trading in March 2014. The operations of the WGSH are potentially relevant to the RBP because one of the trading activities that it facilitates is the sale and purchase of gas delivered via the RBP. In the context of this report, it is appropriate to consider whether trading activities at the WGSH are likely to affect the future demand for transportation services on the RBP.

In this section we briefly review the operation and historical performance of the WGSH, and then consider its implications in terms of the potential demand for services on the RBP to support WGSH trading activities.

5.1 Operation of the WGSH

The gas supply hub was established through amendments to the National Gas Law (NGL) and the National Gas Rules (NGR). In accordance with the amending legislation, AEMO has established an exchange agreement and a set of procedures which set out the terms of participation in the gas supply hub and the terms governing transactions entered into through the exchange.

The WGSH allows generators, gas users, producers, and retailers to manage their daily and future gas requirements by buying and selling gas through an on-line trading platform. Participation is voluntary and is designed to complement existing bilateral gas supply arrangements and gas transportation agreements.

AEMO operates the exchange and provides a range of services to support trading activities.

Participants place anonymous offers to sell, or bids to buy, specified quantities of gas. The offers and bids also specify the prices at which the participants are willing to trade. Offers and bids are automatically matched on the exchange to form transactions.

Products listed on the exchange are for the sale and purchase of gas delivered to one of the three major connecting pipelines at Wallumbilla (RBP, Queensland Gas Pipeline, South West Queensland Pipeline). There are separate products for each pipeline (trading location) and delivery period (daily, day-ahead, balance-of-day, and weekly). Products are available on a short-term basis, thereby providing participants with a means of balancing their gas portfolio requirements around long-term bilateral contracts.

5.1.1 Transportation of gas traded on the hub

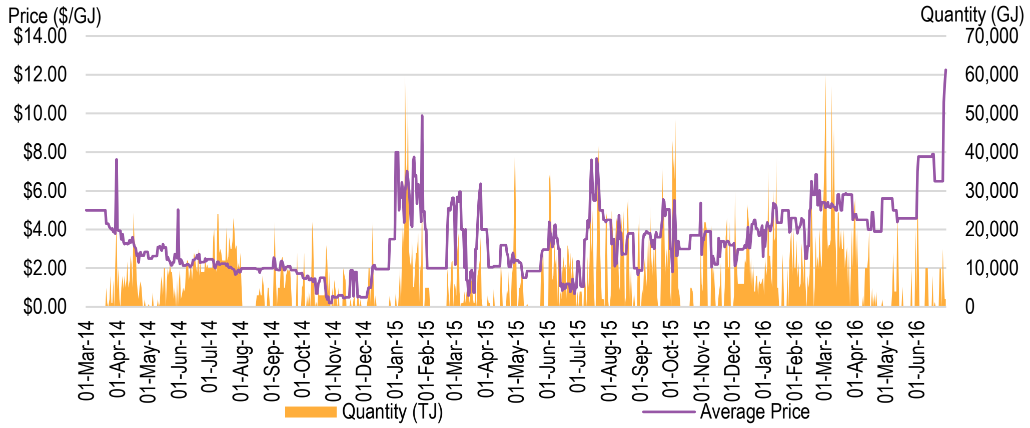
The WGSH trading terms include a warranty that the transacting parties have the necessary transportation rights at the delivery point to deliver and receive gas. AEMO has also implemented a pipeline capacity listing service which allows supply hub participants to advertise an interest to buy or sell spare gas transportation services.

5.2 Historical trading activity

AEMO publishes data on trading activity at the WGSH on a regular basis.

Figure 5.1 shows the daily trading activity (volume traded and average price) for gas delivered to the RBP over the period from commencement of hub trading activities in March 2014. **Figure 5.2** summarises this data on a monthly basis.

FIGURE 5.1 DAILY TRADING ACTIVITY ON THE WALLUMBILLA GAS SUPPLY HUB, RBP DELIVERIES



SOURCE: ACIL ALLEN COMPILATION OF AEMO DATA

FIGURE 5.2 MONTHLY TRADING ACTIVITY ON THE WALLUMBILLA GAS SUPPLY HUB, RBP DELIVERIES

SOURCE: ACIL ALLEN COMPILATION OF AEMO DATA

Comparable data for SWQP and QGC deliveries show that the RBP product is the most actively traded. Nevertheless, the volume of trade on the WGSH for delivery to the RBP remains relatively thin and highly volatile. **Figure 5.1** shows that the average daily quantity traded on RBP over the period since market commencement has been 7.4 TJ/day, while the maximum quantity traded on a single day has been 60 TJ. The total volume of gas traded on RBP since market commencement has been about 6.3 PJ.

The month-on-month variations in quantity of gas traded show no obvious seasonal or other regular pattern; relatively high trading activity in mid-2014 may be related to the build-up of CSG production prior to the commissioning phase for the first train at QCLNG during the second half of 2014. Similarly, the relatively high trading activity from mid-2015 through to early 2016 may be related to CSG ramp-up for QCLNG Train 2, GLNG Trains 1 and 2, and APLNG Train 1, all of which began taking commissioning gas during the period July 2015 to May 2016. There is not a close correlation between levels of dispatch of gas-fired power stations (Oakey, Braemar 1, Braemar 2) and volumes of gas traded at the WGSH.

Over the period April – June 2016, levels of trading activity were low, and prices high. This is consistent with tight gas supply throughout eastern Australia where spot gas prices have risen sharply through the first half of 2016.

5.3 Potential significance of WGSH for RBP

Trading in the WGSH RBP service requires both the seller and the buyer to hold transportation rights on the RBP. Trading participants must make certain amendments to their gas transportation agreements (GTAs) to ensure they can meet delivery obligations under the exchange agreement.

However, this does not necessarily mean that hub traders would need to hold firm transportation entitlements on the pipeline specifically for the purpose of trading. Participants can enter into a “Zero MDQ” gas transportation agreement, which primarily addresses prudential requirements.

Some participants may already hold firm capacity entitlements as part of their day-to-day business. They may then be able to call on those existing entitlements to support their trading activities (which are, by nature, short term arrangements allowing them to balance their gas portfolio requirements around long-term bilateral contracts).

Alternatively, existing firm entitlements may entitle the holders to obtain non-firm services (for example, day-ahead “as-available” service) to support trading activity.

Furthermore, as noted above, AEMO has implemented a pipeline capacity listing service which allows supply hub participants to advertise an interest to buy or sell spare gas transportation services. Traders may be able to use this capacity trading service to secure the transportation rights necessary to execute a trade.

A key question is whether, as a result of the operation of the WGSH, there is likely to be a demand for new or additional services on the RBP *specifically to support trading activities*. We consider it unlikely that the operations of the WGSH will generate a significant demand for new or additional services on the RBP, for the following reasons:

— The transport task is highly variable and unpredictable. In this regard we note that over the first 27 months of hub operations, the quantity of gas traded has varied widely. On approximately one-third of trading days, no gas was traded at all. The average daily quantity traded was 7.4 TJ/day, with a peak trading volume of 60 TJ/day. We consider it unlikely that traders would seek firm transportation services specifically for the purposes of trading in such a volatile market.

— As discussed above, some traders are likely already to hold gas transportation entitlements on RBP that offer sufficient flexibility to support trading activities, without the need to take out additional transportation services specifically for the purposes of trading.

  – What is perhaps more likely is that shippers will seek to negotiate for new or varied flexibility terms within their transportation agreements in order to facilitate trading. The specific provisions would be likely to vary from shipper to shipper, depending on their specific circumstances and the nature of the trading opportunities that they anticipate. Any such arrangements will therefore be in the nature of negotiated services.

— Parties who wish to trade gas on the hub but who do not currently hold transportation services in their own right (for example, industrial Tariff D users who purchase gas on a delivered basis, through a retailer) would be more likely utilise the capacity trading service to obtain access to transport, rather than entering into a firm GTA with the transmission pipeline owner. Alternatively, such users might arrange with their retailer (who will already hold pipeline transport entitlements) to trade their gas entitlements on their behalf.

6 GLADSTONE LNG PLANTS: IMPLICATIONS FOR SERVICES ON THE PIPELINE

In this section we consider the Gladstone LNG plants and what implications—if any—they are likely to have for the future demand for services on the RBP.

6.1 The Gladstone LNG plants

The first CSG LNG project into commercial production—the Shell/BG-led Queensland Curtis LNG (QCLNG) Project—loaded its first LNG cargo in December 2014 and commenced shipments from the second LNG train in August 2015. The QCLNG project is expected to reach full production capacity from its two liquefaction trains in mid-2016. Two other projects—the Santos-led Gladstone LNG Project (GLNG) and Origin/ConocoPhillips Asia Pacific LNG (APLNG)—have both now started shipping LNG, with the GLNG project dispatching its first cargo in October 2015 and APLNG in January 2016.

Altogether the three projects have so far committed to six LNG trains, resulting in total LNG capacity of 25.3 million tonnes per annum (Mtpa). They will require around 1,500 PJ of CSG feed each year for feedstock and ancillary use. This is more than double the size of the current eastern Australian domestic gas market, and will effectively commit some 37,500 PJ of CSG reserves assuming these projects run for 25 years. By 2020 around two-thirds of the gas produced in the region will be exported as LNG. At the same time, the domestic market for gas will contract from around 700 PJ per year to about 500 PJ per year. That contraction will be caused in part by demand responses to higher gas prices as a result of LNG export linkages. However, a more important factor driving the reduction in domestic gas demand is a major shift in the National Electricity Market (NEM) with electricity demand in the NEM having fallen significantly in recent years. A number of factors, including improved energy efficiency and increased penetration of small-scale and large-scale renewables coupled with a lack of direct carbon pricing signals and rising gas prices, are driving a sharp decline in the use of gas for electricity generation.

6.2 Upstream gas developments

The Gladstone LNG plants are unique in that they are the only large-scale LNG plants in the world that draw their feed gas supply predominantly from coal seam gas (CSG) fields. This means that the Gladstone LNG developments rely on literally thousands of CSG production wells distributed across a wide area of the Surat and Bowen Basins in central and southern Queensland.

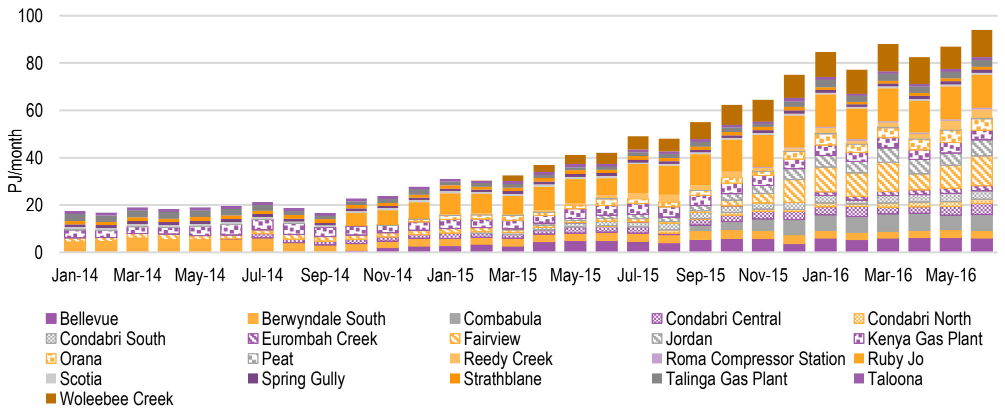
6.2.1 CSG production ramp up

An important factor in considering gas market responses in the transition to LNG exports is the production characteristics of coal seam gas (CSG), which provides most of the feedstock for the LNG plants. Because CSG production wells typically require an extended period of dewatering during which gas production builds up slowly as water production decreases, it was widely expected that prior to LNG start-up there would be excess gas available to the market that would suppress prices (so called "ramp-up gas"). However, it was also expected that that the market would swing from an over-supply situation during the ramp-up period to a potential under-supply position following LNG plant commissioning.

In practice, the ramp-up gas issue did not affect the market to the extent that many had expected, largely because a number of mitigation strategies were employed. These included underground gas storage; turn-down of some CSG wells after establishing production; use of "excess" CSG in power generation; and substitution of CSG for conventional gas within the diversified supply portfolios of some gas producers. Now that five of the six LNG trains at Gladstone have been commissioned, attention has turned to the question of whether or not the ramp up of CSG production will keep pace with the rapid increase in demand, and if not what impact this will have on eastern Australian domestic gas supply.

Data published by the Australian Energy Market Operator on the Natural Gas Services Bulletin Board (**Figure 6.1**) shows that Queensland CSG production built up strongly as the LNG plants were commissioned from late 2014 through to the end of 2015. By September 2015 production had reached an annualised rate of around 660 PJ/a, at which level Queensland CSG for the first time accounted for a level of production equivalent to the entire domestic gas demand of eastern Australia. By January 2016 total production of CSG in Queensland had risen to 85 PJ/month—an annualised rate of more than 1,000 PJ/a. Since then, production has continued to rise, albeit with some month-on-month fluctuations. June 2016 saw aggregate gas production reach a highest-ever level of 94.3 PJ for the month: an annualised rate of about 1,130 PJ/a. By the end of June 2016, some 23 CSG production and processing facilities were contributing to the supply mix.

FIGURE 6.1 RAMP UP OF QUEENSLAND CSG PRODUCTION



SOURCE: ACIL ALLEN COMPILATION OF NATIONAL GAS MARKET BULLETIN BOARD DATA

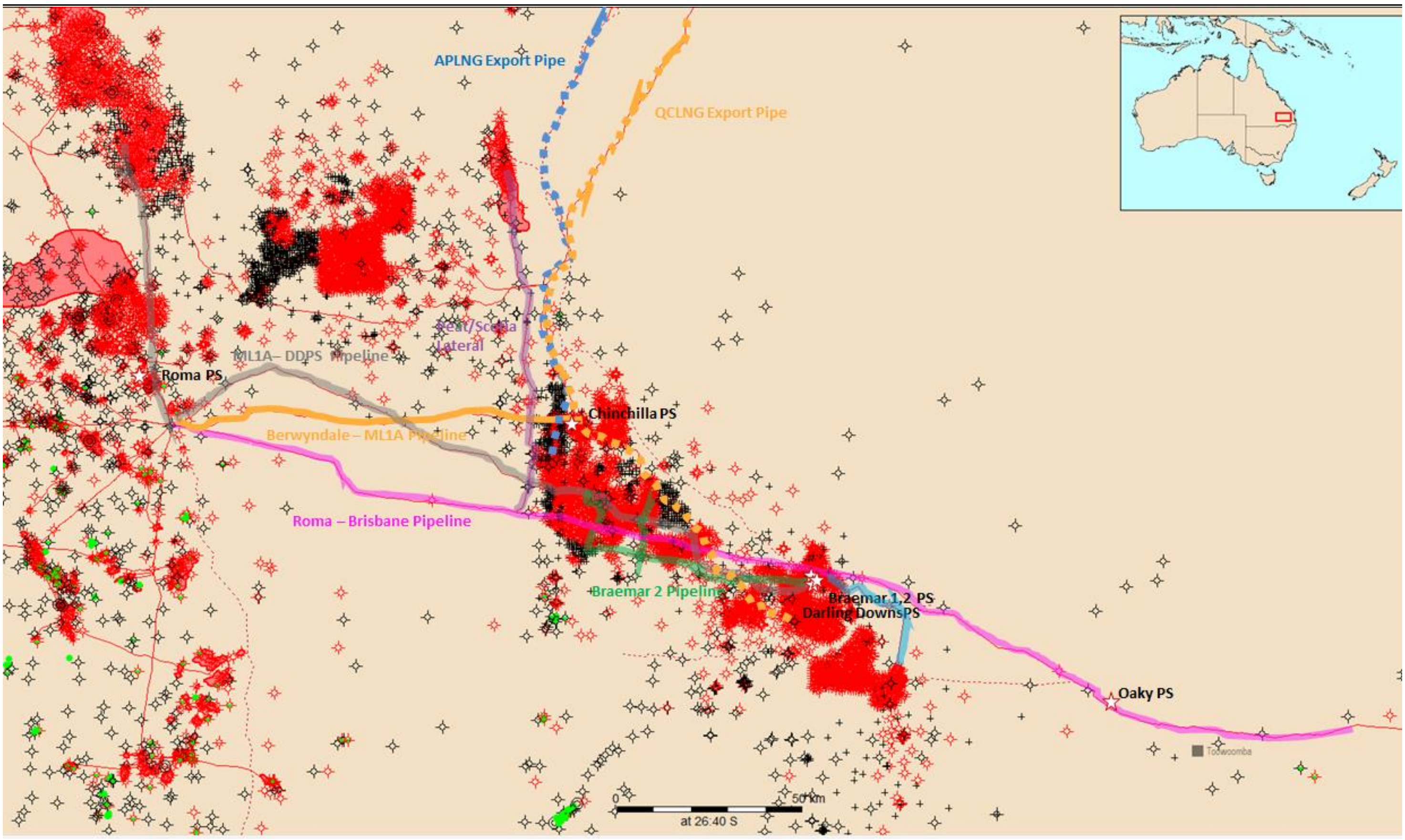
6.3 Implications for RBP

In the context of this study, the key question is what implications—if any—the Gladstone LNG projects and their associated upstream CSG developments have for the RBP. In particular, we need to consider whether these developments are likely to result in demand for new or additional services on the RBP during the next access arrangement period.

In section 2.3 we noted that the RBP is not a primary source of transport services for the CSG LNG projects and that each of the three LNG projects has developed its own dedicated gas gathering, processing, compression and transportation system. However we also noted that some CSG producers in the area have, from time to time, used services on the RBP as a means of providing operational flexibility, allowing gas to be temporarily redirected to underground storage facilities, gas-fired generators or short-term/spot gas buyers.

Figure 6.2 shows the location of CSG wells that currently support the Gladstone LNG projects relative to the RBP. As can be seen, there are numerous “clusters” of close-spaced CSG wells. Each cluster is referred to as a CSG field. Each CSG well has an expected productive life of around 10–15 years, although this is likely to vary considerably both within and between individual fields. The implication is that, over the 20-year plus life of the LNG projects, many more CSG wells will have to be drilled to augment and replace the wells currently in production. The extensive upstream CSG developments have seen the establishment of numerous gas gathering and transmission pipelines. Some of these connect to the RBP while others represent alternative transport pathways that effectively bypass the RBP.

FIGURE 6.2 LOCATION OF CSG FIELDS SUPPORTING THE GLADSTONE LNG PROJECTS



SOURCE: ACIL ALLEN CONSULTING. BASE MAP FROM ENCOM GPINFO

While the majority of the gas supplied to the Gladstone LNG plants will not be transported on the RBP, it is apparent that the RBP could provide a number of “supporting services” that may be called on by the LNG project operators in certain circumstances. Examples of services that the RBP could provide to the LNG projects include:

— Western Haul services to move gas from CSG fields in the eastern Surat Basin either to Wallumbilla or to mid-line delivery points at which the gas could be transferred into the CSG LNG delivery systems. Western Haul service is discussed further in section 6.4.

— Short-term services to allow temporary redirection of CSG to gas-fired power generators in the event of planned or unplanned disruptions to LNG production where other means of dealing with excess CSG production (such as well turn-down and underground gas storage) have been exhausted.

6.4 Western Haul Service

Since mid-2015 gas has been able to flow in the RBP from east to west, allowing delivery to Wallumbilla or intermediate delivery points. “Western Haul” services commenced at around the same time as the second period of major ramp-up in LNG production at Gladstone.

Gas flowing to Wallumbilla can be redirected into one or more of the Gladstone LNG plants, or into underground storage. Alternatively, the gas could be transferred into either the South West Queensland Gas Pipeline or the Queensland Gas Pipeline for onward transport to domestic customers in western and central Queensland or southern States.

The future level of demand for RBP Western Haul services, from LNG projects and other users, is discussed in detail in Chapter 7.

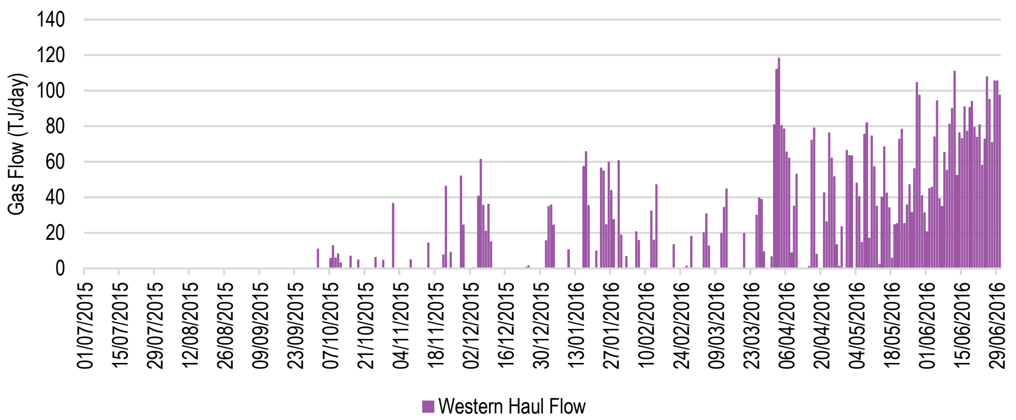
7 RBP WESTERN HAUL SERVICE: ASSESSMENT OF FUTURE DEMAND AND PRICING

7.1 Overview of the Western Haul Service

During 2015 APA completed engineering works to enable gas to flow in the RBP from east to west, allowing delivery to Wallumbilla or intermediate delivery points. "Western Haul" services commenced in mid-2015 at around the same time as the second period of major ramp-up in LNG production at Gladstone.

Western Haul flows on the RBP are calculated as the net receipts into the RBP at Wallumbilla (recorded at five receipt meters) minus deliveries to Wallumbilla (recorded at the Wallumbilla exit meter), with negative values indicating western flow and positive values eastern flow. This is consistent with the reporting of RBP flows on the Natural Gas Services Bulletin Board. Over the past 12 months, the Western Haul service has accounted for a substantial proportion of total deliveries on RBP. **Figure 7.1** shows the levels of Western Haul flow to Wallumbilla on a daily basis from July 2015 to June 2016 (converted from net negative values to positive values). There has been a high degree of variability in the daily flow rates, but over the first six months of 2016 the rate of Western Haul flow showed a clear rising trend. Peak rates reached about 118 TJ/day in April 2016, with average daily rates of 75 TJ/day in June 2016.

FIGURE 7.1 WESTERN HAUL GAS FLOW TO WALLUMBILLA: NOVEMBER 2015 – JUNE 2016



SOURCE: APA GROUP

A key question is whether this high level of use of the Western Haul service is an indicator of sustained future demand for the service, or a short-term, transient phenomenon associated with the ramp-up of the LNG plants and associated transitional issues.

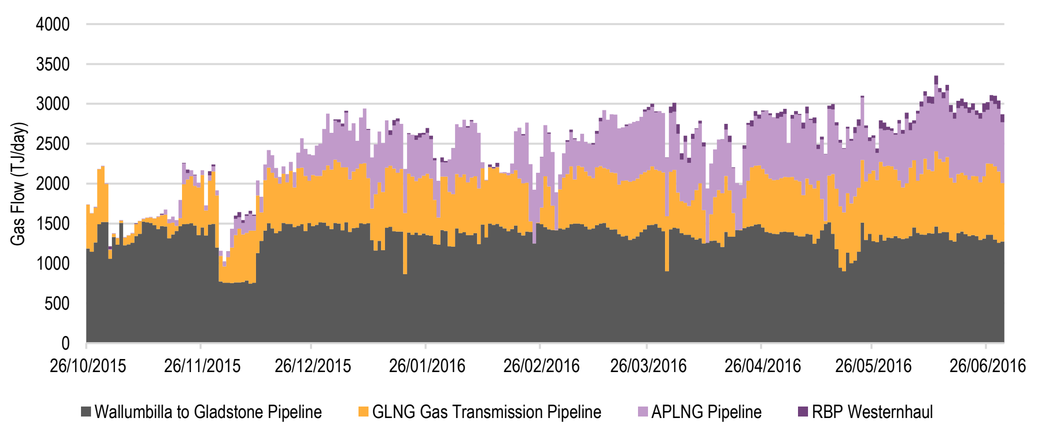
Gas flowing to Wallumbilla can be redirected into one or more of the Gladstone LNG plants, or into underground storage. Alternatively, the gas could be transferred into either the South West Queensland Gas Pipeline or the Queensland Gas Pipeline for onward transport to domestic customers in western and central Queensland or southern States.

We expect that there will be some future seasonal (winter) demand for Western Haul services to enable gas to be moved from the Surat and Bowen Basin CSG fields to customers in southern States. The demand for such services is likely to depend on year-to-year variations in seasonal conditions (the 2016 winter appears to have been more severe than usual) and also on the alternative transportation pathways available to different producers. Another consideration will be the extent to which Surat/Bowen CSG supply is available to meet this seasonal demand: that is not clear beyond current domestic gas supply contracts and the Stanwell on-sale arrangement which expires in 2017. A further consideration will be the extent to which seasonal demand in the southern States can or cannot continue to be met from the Cooper Basin (see section 2.1.3).

Another potential source of demand for Western Haul services relates to the LNG projects. As discussed in section 6.3, the RBP is not a primary source of transport services for the CSG LNG projects, each of the projects having developed its own dedicated gas gathering, processing, compression and transportation system. However the projects are likely to use services on the RBP as a means of providing operational flexibility, allowing gas to be temporarily redirected to underground storage facilities, gas-fired generators or short-term/spot gas buyers when it is operationally desirable for them to do so.

Figure 7.2 compares the levels of Western Haul gas flow on RBP with flow through the three main LNG export pipelines. This emphasises the fact that, while recent levels of Western Haul flow have been significant in the context of the RBP, they have amounted to little more than marginal balancing flows for the LNG projects.

FIGURE 7.2 WESTERN HAUL GAS FLOW COMPARED WITH LNG PIPELINE FLOWS



SOURCE: AEMO NATURAL GAS SERVICES BULLETIN BOARD DATA; APA GROUP

The LNG projects can be expected to continue to seek Western Haul services on the RBP from time to time, on a temporary basis, to deal with operational issues as they arise. However it is not clear that such requirements will lead to a demand for long-term firm contractual arrangements. We think it more likely that the service requests will be short-term and essentially opportunistic in nature, to deal with emergent issues, and will have service requirements dictated by the specific circumstances in which they are sought.

In the following sections we look in more detail at the current and potential users of the Western Haul service, and the nature of their service requirements.

7.2 Historical patterns

Given that the Western Haul service has been available for only a short period of time, there is relatively little history to indicate likely future patterns of usage. Information provided by APA shows that the levels of Western Haul flow seen during the first half of 2016 have generally not been supported by parties entering into firm transportation contracts. Volumes have been significantly affected by transient requirements.

7.2.1 Western Haul service contracts

Information provided by APA indicates that:

— One shipper has taken out a long-term (8 years) firm contract for a relatively small Western Haul volume (20 TJ/day initially, declining after the first year to10 TJ/day).

— One shipper has taken out a short-term firm contract for a small Western Haul volume (10 TJ/day over 2 years).

— One shipper held a short term seasonal firm contract (three months) over a relatively small volume (5 to 15 TJ/d); this contract has expired.

— Four shippers have taken out variable (non-firm) contracts for as-available or interruptible services. These arrangements have no minimum capacity reservations and hence no guaranteed revenues.

Given that the total firm contracted Western Haul capacity has not exceeded 45 TJ/day (and on the basis of current contracts will fall to 20 TJ/day in 2017), most of the Western Haul services that were utilised during the second quarter of 2016 relied on non-firm (as-available or interruptible) service.

During the first half of 2016 Western Haul volumes were significantly affected by transient requirements that are unlikely to translate into regular demand for service in the future.

— Part of the increased Western Haul flow related to a short-term arrangement to allow supply to domestic markets to meet a seasonal increase in demand. The gas supplier in question has made no commitment to use similar seasonal services in future.

— Part of the increased Western Haul flow related to a short-term arrangement to deal with an upstream operational issue faced by one of the LNG projects. That issue has since been resolved and the western flow service has terminated.

7.2.2 Nature of the services

The Western Haul services provided to date have involved:

— Gas injection at various points on the RBP mid-line.

— Gas delivery at Wallumbilla, for onward delivery into other systems (for example, into SWQP, into QGP, into gas storage or into the upstream infrastructure of CSG LNG projects).

  – Gas delivery into SWQP could be for purposes of onward delivery to customers in Western Queensland or southern States. Alternatively gas could be delivered into SWQP for temporary storage (in line pack) for subsequent return via Wallumbilla to LNG plants in Gladstone.

7.3 Future patterns of Western Haul use

7.3.1 User identification

In this section we consider who will (or might) use the service in future, and what alternatives they are likely to have available. We have identified five categories of potential Western Haul User:

1. CSG LNG Producers: Shell (QGC/Arrow); APLNG; GLNG.
2. Energy retailers: AGL, EnergyAustralia, Origin Energy, Alinta Energy.
3. Other producers.
4. Major domestic gas users looking to on-sell gas entitlements eg Swanbank E, Incitec Pivot.
5. Spot market traders (likely to be captured in the preceding categories).

For each of these potential Western Haul user categories we consider why, and in what circumstances, they might make use of the service. For example, the service could be used:

- to deliver gas to an LNG plant
- to divert "balancing" gas volumes, temporarily or permanently, from CSG LNG fields to storage, internal swaps or third-party buyers
- to deliver gas to Wallumbilla for onward carriage to customers via SWQP or QGP
- to deliver gas in the direction of Wallumbilla for third-party buyers of on-sold gas entitlements
- to deliver gas to Wallumbilla for trading at WGSH.

We also need to consider, for each potential customer:

- how much service they would physically use (average/peak)
- what their physical usage profile would look like
- what alternatives they have and what those alternatives would cost them
- how much the user might be willing to pay to access RBP Western Haul Service and what the drivers of those price tolerances are
  - on a firm capacity basis, essentially providing them with an option over the use of the service which they could either exercise to move gas, or trade/on-sell to other users
  - on an as-available basis, paying only on the days when they need it.

7.3.2 Potential Customer review

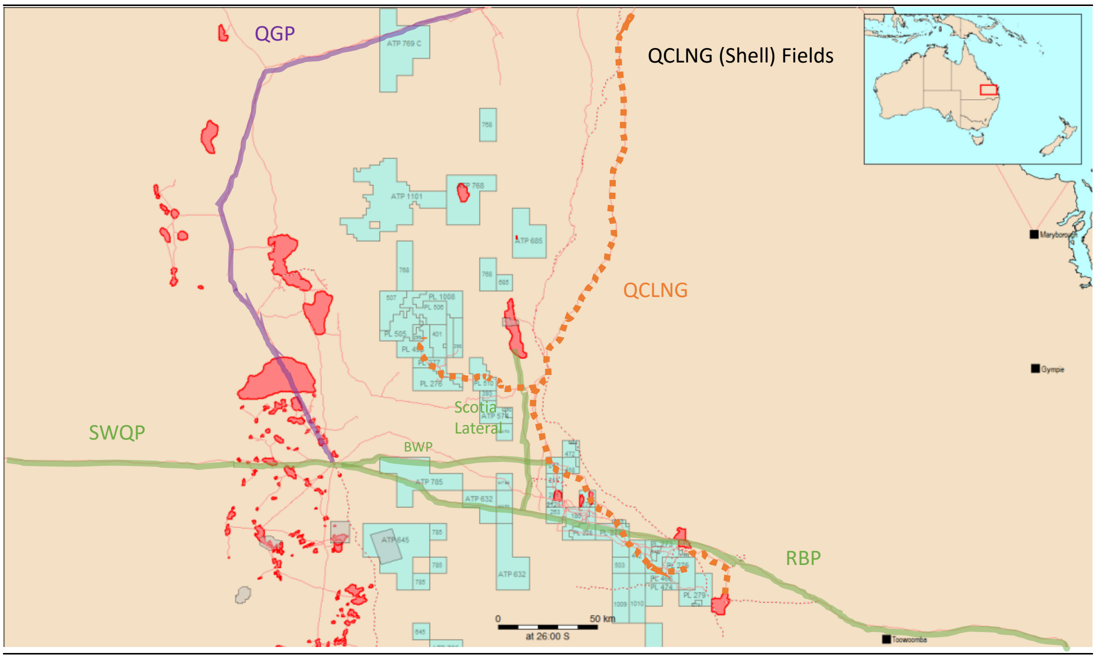
1. CSG LNG Producers

Shell QCLNG

<u>Prospective use of service</u>

The exploration tenements and associated infrastructure supporting the Shell QCLNG project are shown in **Figure 7.3**. For its normal day-to-day operations, QCLNG has access to dedicated infrastructure that negates any need to access RBP Western Haul service.

FIGURE 7.3 SHELL QCLNG GAS DELIVERY INFRASTRUCTURE



SOURCE: ACIL ALLEN COMPILATION OF DATA FROM ENCOM GPINFO AND QUEENSLAND GOVERNMENT "QUEENSLAND GLOBE" DATA

There are a number of exploration tenements in the vicinity of the RBP between Wallumbilla and Condamine (ATP 785, ATP 632, ATP 647, ATP 645) that are not proximate to the existing QCLNG pipeline assets. However according to Queensland Government data[28] these exploration tenements do not currently host any CSG wells.

QCLNG could look to use the RBP Western Haul service on a short-term, temporary basis to redirect gas to Wallumbilla in the event of unplanned outages at the LNG plant (requiring short-term diversion of upstream production), disruptions to their upstream pipeline operations, or to send gas that is surplus to requirements to storage or domestic market sales. QCLNG has a storage services agreement with AGL for the Silver Springs storage facility, south of Wallumbilla.

<u>Alternatives to Western Haul service</u>

For most purposes, QCLNG can be expected to make use of its own dedicated infrastructure. QCLNG's large diameter export LNG line (Wallumbilla – Gladstone Pipeline, WGP) is now owned by APA. However QCLNG holds long term capacity rights to the infrastructure under a GTA that underpinned the sale process. These transport entitlements represent a sunk cost to QCLNG.

An alternative route to Wallumbilla is provided by the Berwyndale – Wallumbilla Pipeline (BWP). The BWP is a 112 km long, 400mm (16 inch) diameter pipeline with a maximum capacity without midline compression of 120 TJ/day (ACIL Allen estimate). It was built by AGL in 2009 to allow transport of gas from the Berwyndale CSG fields under a long-term (20 year) gas sales agreement with QGC. The BWP was sold to APA in 2010, with AGL entering into a long-term gas transportation agreement that accounts for most if not all the available capacity in the pipeline. QGC can use the pipeline, on an interruptible basis and for a nominal fee, to transport gas from its production interests in the Berwyndale area to Wallumbilla[29].

Given this alternative, QGC would be unlikely to pay for Western Haul transport on RBP except in circumstances where a) it is unable, for operational reasons, to utilise its own dedicated infrastructure, and b) the low-cost interruptible service on BWP is not available or the available capacity is insufficient to meet its requirements.

<u>Quantum of service</u>

Given the very large volumes of CSG produced by the QCLNG project from its Surat Basin tenements (in excess of 1,000 TJ/day), there is potential for QCLNG to make use of large volumes of RBP Western Haul services (taking up all available capacity, currently 120 TJ/day) on those infrequent, short-term occasions when it may be operationally desirable to do so.

<u>Demand profile</u>

Likely to be very intermittent, with high demand for short periods separated by long periods of zero demand.

<u>Price tolerance</u>

Given the expected intermittent load profile, QCLNG is unlikely to seek firm service. On the rare occasions when sunk-cost or low-cost alternatives are not available via the QCLNG infrastructure and/or BWP, access to non-firm service Western Haul service on RBP will be valuable given that the alternative may be to flare gas.

Shell Arrow

<u>Prospective use of service</u>

The Surat Basin exploration tenements and associated infrastructure supporting the Shell Arrow project are shown in **Figure 7.4**. Up until 2014, Shell and its joint venture partner were pursuing a separate, freestanding LNG project at Gladstone—Arrow LNG—based on gas supply from Arrow's interests in the northern Bowen Basin and the eastern Surat Basin. However, Shell subsequently announced that was not proceeding with the Arrow LNG project. Shell now owns a majority interest in the QCLNG project (following Shell's takeover of BG Group). As a result, the Arrow CSG assets may now be used to supply additional gas into the QCLNG project, in which case the prospective use of RBP Western Haul services by Arrow would most likely mirror that of the QCLNG Project, discussed

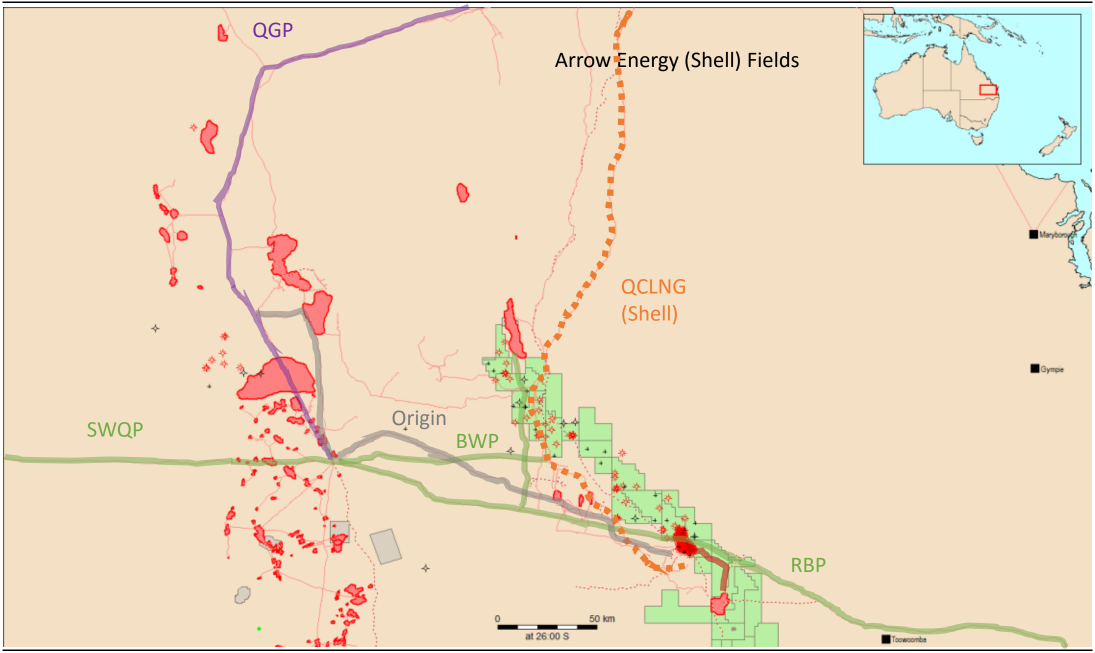
[28] Queensland Globe, Coal Seam Gas Data Set, Well (CSG)
[29] The BWP does not connect directly to the WGP; the intervening pipe is owned and controlled by QGC. Hence APA is unable to provide a seamless third party service between Gladstone and Wallumbilla via the BWP.

in the previous section. However another possibility is that Shell will negotiate to supply gas from the Arrow Surat Basin tenements to one of the other LNG projects (GLNG and/or APLNG) or to domestic customers. In that case, Shell Arrow could use RBP Western Haul services to transport gas from its eastern Surat tenements to Wallumbilla, from where it could access both GLNG and APLNG as well as domestic markets in western Queensland and southern States.

Alternatives to Western Haul service

In the event that the Arrow Surat CSG gas resources are developed as supplementary supply into the QCLNG project, they would most likely be transported to Gladstone through the existing QCLNG infrastructure which traverses the Arrow tenements (see **Figure 7.4**).

FIGURE 7.4 SHELL ARROW GAS DELIVERY INFRASTRUCTURE



SOURCE: ACIL ALLEN COMPILATION OF DATA FROM ENCOM GPINFO AND QUEENSLAND GOVERNMENT "QUEENSLAND GLOBE" DATA

If Arrow gas is supplied to one of the other LNG projects (GLNG and/or APLNG) or to domestic customers then Shell could look to transfer gas to Wallumbilla either via the BWP or via RBP Western Haul service (thereby minimising the need to construct new pipeline infrastructure). As discussed in the previous section, Shell has access (through QGC) to interruptible delivery services, at nominal cost, on the Berwyndale – Wallumbilla Pipeline (BWP). It would logically use this service in preference to RBP Western Haul service as a means of delivering gas to Wallumbilla for third party sale, provided an interruptible service is acceptable and the capacity available is sufficient. However, if Arrow contracts with a third party for firm gas supply, the BWP service may not provide a sufficiently secure transportation service. In this case:

— If Arrow gas is sold to APLNG then the Origin Energy pipelines Talinga to Wallumbilla and Talinga to Darling Downs PS and/or the APLNG export infrastructure would offer the preferred routes for firm transport of gas to Wallumbilla or direct to Gladstone.
— If Arrow gas is sold to AGL then AGL's firm capacity rights on the BWP would provide the preferred route for firm transport of gas to Wallumbilla.
— If Arrow gas is sold to Origin Energy then the Origin Energy pipelines Talinga to Wallumbilla and Talinga to Darling Downs PS would offer the preferred route for firm transport of gas to Wallumbilla.
— If Arrow gas is sold to GLNG then the RBP Western Haul service may provide the preferred route for firm transport of gas to Wallumbilla, given that GLNG does not have its own or associated transport infrastructure in the vicinity of the Arrow Eastern Surat Basin fields.

If Arrow gas is sold to a domestic gas buyer other than AGL or Origin Energy, then the RBP Western Haul service may provide the preferred route for firm transport of gas to Wallumbilla. The question of whether or not Arrow gas sold to a third party is likely to be a user of RBP Western Haul service depends very much on who the buyer is and where the gas will be used: APLNG, Origin Energy and AGL all have access to their own infrastructure or to existing transport entitlements that would take priority over RBP Western Haul service. GLNG and other domestic users buying Arrow gas may find that RBP Western Haul service provides the best option for firm transport to Wallumbilla.

Quantum of service

Shell has not at this stage announced any arrangements to supply Arrow Eastern Surat gas to anyone. Any conclusions concerning the quantum of Arrow gas that will be produced, and the amount of such gas that might use RBP Western Haul service would therefore be purely speculative.

Demand profile

If Shell Arrow Eastern Surat CSG is produced and sold to QCLNG, APLNG, AGL or Origin Energy, then RBP Western Haul service will only be used as a “service of last resort” when preferred transport services are unavailable or inadequate. In such circumstances the demand is likely to be very intermittent, with high demand (potentially utilising all available capacity, currently 120 TJ/day) for short periods separated by long periods of zero demand.

If Shell Arrow Eastern Surat CSG is produced and sold to GLNG or to domestic buyers in western Queensland or southern States (other than AGL or Origin Energy), then firm Western Haul service on RBP may provide the preferred means of transporting gas from the Arrow fields to Wallumbilla for onward shipment. In such cases a much flatter and more consistent demand profile could be expected.

Potential use of RBP Western Haul service for Shell Arrow’s eastern Surat Basin domestic gas fields (Tipton West, Kogan North) is discussed separately under the heading “Other Non-LNG gas producers”.

Price tolerance

If Shell Arrow Eastern Surat CSG is sold to QCLNG, APLNG, AGL or Origin Energy then, given the expected intermittent load profile, it is unlikely that these buyers would seek any firm service. On the rare occasions when preferred transport alternatives are not available, access to non-firm service Western Haul service on RBP may be sought on an as-available or interruptible basis. Price tolerance in those circumstances is likely to be high given the consequences of being unable to meet contractual deliveries.

If Shell Arrow Eastern Surat CSG is sold to GLNG, or to domestic buyers in western Queensland or southern States other than AGL or Origin Energy, their price tolerance for firm service is likely to be determined by the bypass cost of building an alternative pipeline to transport gas to Wallumbilla (as was done in the past by AGL, building the BWP). On the basis of a 200 km, 16 inch bypass pipeline carrying an average 250 TJ/day over 15 years, ACIL Allen estimates a bypass cost of $0.48/GJ at 100 per cent load factor.

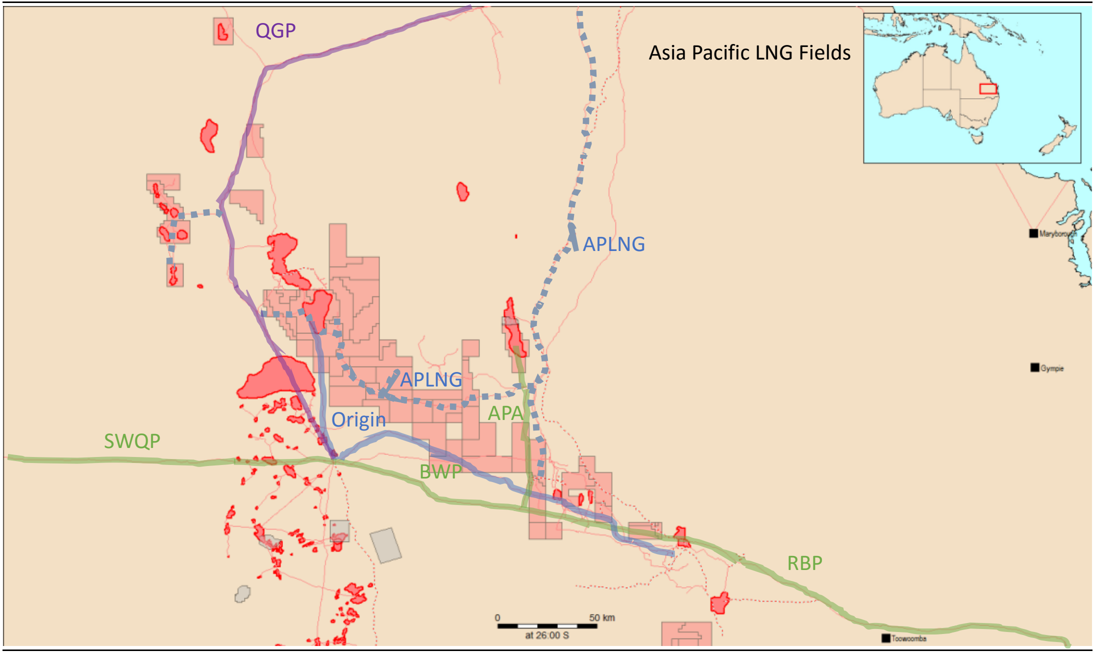
Asia Pacific LNG

Prospective use of service

The Asia Pacific LNG project (APLNG) is operated by Origin Energy (upstream) and ConocoPhillips (downstream). The exploration tenements and associated infrastructure that supports the APLNG project are shown in **Figure 7.5**. For normal day-to-day operations, APLNG has access to dedicated infrastructure that negates any need to access RBP Western Haul service. As shown in **Figure 7.5**, all of the exploration and production tenements in APLNG’s Surat Basin and Bowen Basin (Comet Ridge) areas have good access to this dedicated infrastructure.

Nevertheless, APLNG could look to use the RBP Western Haul service on a short-term, temporary basis to redirect gas to Wallumbilla in the event of unplanned outages at the LNG plant (requiring short-term diversion of upstream production) or to send gas that is surplus to requirements to storage or domestic market sales. APLNG, through Origin Energy, has access to gas storage facilities near Wallumbilla as well as an extensive retail gas sales and gas-fired generation portfolio covering much of the eastern Australian market.

FIGURE 7.5 APLNG GAS DELIVERY INFRASTRUCTURE



SOURCE: ACIL ALLEN COMPILATION OF DATA FROM ENCOM GPINFO AND QUEENSLAND GOVERNMENT "QUEENSLAND GLOBE" DATA

Alternatives to Western Haul service

For most purposes, APLNG can be expected to make use of its own dedicated infrastructure. APLNG owns the large diameter export LNG line from Talinga to Gladstone, and header line from Talinga to Spring Gully. APLNG also owns PPL 143 which links the Spring Gully CSG field (on the Comet Ridge) to the Queensland Gas Pipeline (Jemena) which provides a transportation pathway to Gladstone and Wallumbilla. Origin Energy also owns the Spring Gully to Wallumbilla Pipeline (PPL 90; 324mm, 12 inch, approx. uncompressed capacity 50 TJ/day) and the Wallumbilla – Talinga – Darling Downs Power Station pipeline system (PPL 133, 134; 450mm, 18 inch, approx. uncompressed capacity 150 TJ/day). These transport options represent sunk costs to APLNG and Origin. Given these alternatives, APLNG would be unlikely to pay for Western Haul transport on RBP except in circumstances where it is unable, for operational reasons, to utilise its own dedicated infrastructure. It already has access to its own pipelines from Spring Gully and Talinga to Wallumbilla. These provide effective backup, allowing diversion of gas from the APLNG export pipeline system to Wallumbilla.

APLNG could use RBP Western Haul service to move gas from the Peat field to Wallumbilla via the Scotia – Peat Lateral. However, GLNG has built a pipeline connecting the adjoining Scotia field to the APLNG pipeline (apparently to allow Santos Scotia gas to be delivered to GLNG's Gladstone facility under a commercial arrangement with APLNG). Presumably, therefore, APLNG could utilise this tie-in to its export pipeline in order to deliver gas from Peat to Gladstone without the need to travel via Wallumbilla.

It is therefore difficult to conceive of a situation in which APLNG would make use of RBP Western Haul services.

Quantum of service

Nil. It is difficult to conceive of a situation in which APLNG would make use of RBP Western Haul services.

Demand profile

Nil. It is difficult to conceive of a situation in which APLNG would make use of RBP Western Haul services.

Price tolerance

Not applicable.

Santos GLNG

Prospective use of service

The Gladstone LNG project (GLNG) is operated by Santos on behalf of a consortium comprising Santos, Petronas, Kogas and Total. Of the three operating LNG projects at Gladstone, GLNG is the most reliant on third party gas supply to supplement its own gas sources. Its prospective use of RBP Western Haul services therefore relates not only to movement of equity gas from its controlled exploration and production areas, but also to movement of third party gas purchased for its GLNG operations. Being fundamentally a buyer of gas from the domestic market, GLNG is unlikely to require transport services to enable it to deliver gas into the domestic market.

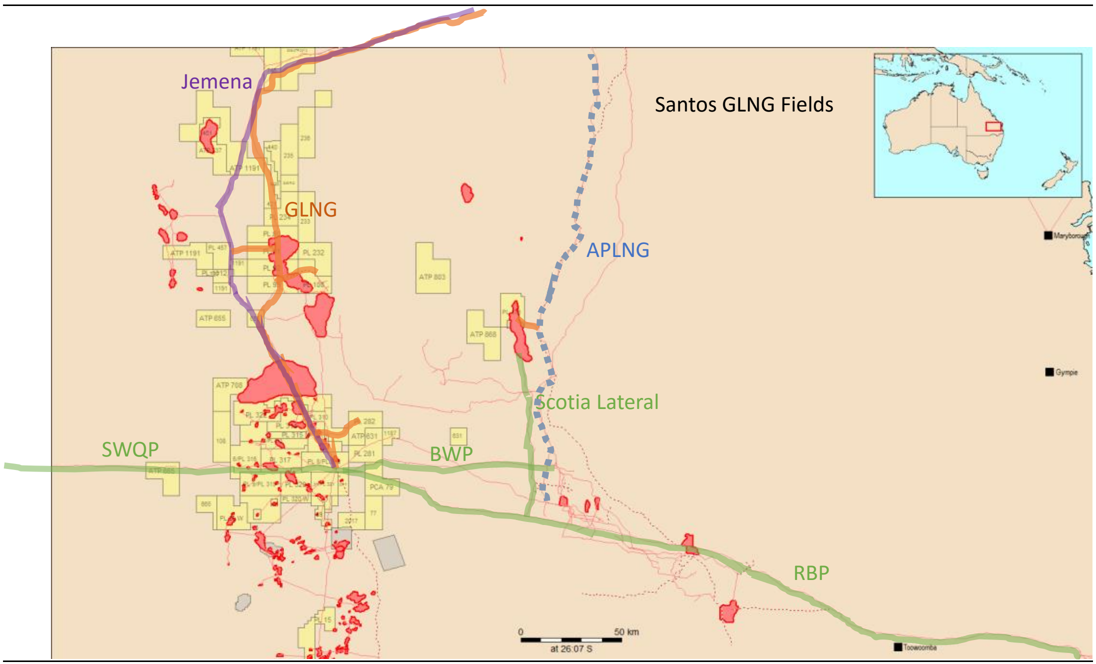
The exploration tenements and associated infrastructure that supports the GLNG project are shown in **Figure 7.6**. For its normal day-to-day operations, GLNG has access to dedicated infrastructure that negates any need to access RBP Western Haul service.

GLNG also purchases gas from the following third party suppliers[30]:

— Santos Cooper Basin 140 TJ/day, delivered at Wallumbilla
— Origin Energy 150 – 200 TJ/day, delivered at Wallumbilla
— Meridian Seamgas 20 – 65 TJ/day, delivered at GLNG Gas Transfer Point (north of Moura)
— Santos Combabula/Spring Gully, 30 – 50 TJ/day, delivered at Fairview
— AGL ex Queensland CSG, 65 TJ/day, delivered at Wallumbilla[31]
— “Other suppliers”, 70 – 115 TJ/day, delivered at Wallumbilla.

None of these third party supply arrangements requires GLNG to transport gas on RBP.

FIGURE 7.6 SANTOS GLNG GAS DELIVERY INFRASTRUCTURE



SOURCE: ACIL ALLEN COMPILATION OF DATA FROM ENCOM GPINFO AND QUEENSLAND GOVERNMENT “QUEENSLAND GLOBE” DATA

GLNG could look to use the RBP Western Haul service if it were to acquire third party gas from a location in the eastern Surat Basin (for example, from Shell Arrow’s eastern Surat fields, or on-sale of

[30] Details set out in Santos presentation to Macquarie Australia Conference dated 7 May 2015, plus Santos media release dated 24 December 2015 (re AGL gas purchase agreement).
[31] The Santos media release announcing the AGL gas purchase agreement identifies Wallumbilla as the delivery point.

contract gas entitlements by a current large gas user). However, as discussed above, none of GLNG's disclosed third-party gas supply arrangements require transportation on RBP or access to RBP Western Haul service.

Given the physical location of its gas supply sources, which for the most part lie north and west of the RBP, it is difficult to see GLNG utilising RBP Western Haul service even to accommodate unplanned plant outages: such events could be accommodated by curtailing deliveries at Wallumbilla and/or Fairview and by injecting gas into line-pack storage on SWQP and/or underground storage at Roma or Cooper Basin.

Alternatives to Western Haul service

As shown in **Figure 7.6** most of the exploration and production tenements supporting the GLNG project are located to the north of Wallumbilla along the route of the GLNG export pipeline (which parallels Jemena's Queensland Gas Pipeline (QGP) for much of its distance). Because most of these tenements are located to the north or north-west of the RBP, gas produced from those areas cannot flow west on RBP. Those GLNG tenements immediately to the east of Wallumbilla (PL310, ATP 631) are connected by a GLNG-owned branch pipeline (PPL 2020) to GLNG's Comet River – Wallumbilla Pipeline (PPL 118), which in turn connects to the main GLNG export system at Fairview. ATP 631/PCA78, located some 40 km north of the RBP and 65 km east of Wallumbilla currently contains only two CSG wells which are not in production.

GLNG could use RBP Western Haul service to move gas from the Scotia field to Wallumbilla via the Scotia – Peat Lateral. However, GLNG has built a pipeline connecting the Scotia field to the APLNG pipeline (PPL 193) apparently to allow Santos Scotia gas to be delivered to GLNG's Gladstone facility under a commercial arrangement with APLNG. GLNG could utilise this tie-in to allow delivery of gas from Scotia to Gladstone without the need to travel via Wallumbilla.

Quantum of service

Nil under current supply arrangements. RBP Western Haul services could be used routinely if GLNG enters into new third party supply arrangements with an eastern Surat producer such as Shell Arrow. However no such supply arrangements have been agreed and any conclusions concerning the quantum of such gas that might be procured and the amount of such gas that might use RBP Western Haul service would be purely speculative.

Demand profile

Nil under current supply arrangements. Given the physical location of its gas supply sources, it is difficult to see GLNG utilising RBP Western Haul service even to accommodate unplanned plant outages.

Price tolerance

Not applicable.

2. Energy retailers

AGL

Prospective use of service

AGL has in place a long-term gas supply agreement with QGC for purchase of gas from QGC's CSG production areas around Berwyndale. That deal, announced in late 2006, was for purchase of 540 PJ of gas over 20 years from 2008 (therefore expiring 2027), an average rate of 27 PJ/a or 74 TJ/day. AGL also held options under that agreement to increase the amount of gas supplied under the agreement by up to 200 PJ in two equal tranches (on average 5 + 5 PJ/a). Part of that gas supply was sold by AGL into a 138 PJ, 11.5 year gas supply contract to Mount Isa, commencing in 2013, utilising "existing gas transportation arrangements in the Berwyndale-Wallumbilla Pipeline, South West Queensland Pipeline and Silver Springs Gas Storage Facility".[32] A further 254 PJ from the AGL/QGC contract was sold to GLNG (ex Wallumbilla) under an 11 year supply agreement commencing 2017

[32] "AGL and APA to develop new Mt Isa gas fired power station. AGL signs ten year contract to supply gas" AGL Media Release dated 6 October 2011.

(therefore terminating in 2028, synchronous with the end of the AGL/QGC supply contract). Under this arrangement, AGL "… is able to continue to utilise Queensland gas during periods of high east coast demand".[33]

AGL could use RBP Western Haul services to deliver gas to Wallumbilla to service these supply arrangements. However as discussed below it is currently using alternative services on the Berwyndale – Wallumbilla Pipeline.

<u>Alternatives to Western Haul service</u>

Following its agreement with QGC in 2006, AGL constructed the Berwyndale – Wallumbilla Pipeline (BWP) in order to be able to transport gas purchased under that contract to Wallumbilla, for onward shipment to its customers. AGL subsequently (in 2010) sold the BWP to APA Group, with AGL entering into a 17 year gas transportation agreement with APA. This accounted for most if not all of the capacity in the pipeline, and is now effectively a sunk cost for AGL. Consequently AGL's preferred means of transporting gas from Berwyndale to meet its Mount Isa and GLNG commitments will be via BWP. AGL would only use RBP Western Haul services as a back-up in the event that there was a disruption to services on the BWP.

<u>Quantum of service</u>

We calculate AGL's remaining net gas entitlements ex Berwyndale (after GLNG and Mt Isa sales) to be no more than 6 to 5 TJ/d, assuming the options under the QGC contract were exercised. As mentioned, there is also some redraw entitlement under GLNG deal. On this basis we assume that AGL may contract for up to 10 TJ/day of firm RBP Western Haul capacity to ensure capacity to move this gas west from Wallumbilla during peak demand periods. Given the winter peak requirements of AGL's southern customer base, it is possible that AGL would seek this 10 TJ/day capacity on a seasonal basis rather than as a long-term firm service. In any case we expect that primary carriage will make use of existing BWP entitlements and therefore the RBP arrangement would be to supply an alternative back-up option. AGL could use 60 TJ/day non-firm RBP Western Haul service for GLNG supply if the BWP was temporarily unavailable to meet GLNG deliveries. Similarly AGL could use around 30 TJ/day non-firm RBP Western Haul service if BWP was temporarily unavailable to meet Mount Isa supply.

<u>Demand profile</u>

We assume 10 TJ/day firm RBP Western Haul plus 90 TJ/day non-firm used at very low frequency (0 to 2% per year; assume 1%).

We regard these as a generous allowances, given that a) the 10 TJ/day firm allowance would be a back-up arrangement which, if taken at all, may be taken on a seasonal (3–4 month) basis rather than as long-term firm service, and b) a 1% probability for non-firm service implies that AGL's existing BWP transport arrangements are disrupted for 3 to 4 days per year. This is a much higher outage rate than actually observed for BWP (or other high-pressure gas transmission pipelines in eastern Australia) and is well beyond normal operational allowances.

<u>Price tolerance</u>

The assumed firm booking will provide back-up service to gas delivery via BWP. The alternative would be to access gas stored in line-pack on SWQP or other transmission pipelines proximate to southern customers, or gas held in underground storage at Silver Springs or Cooper Basin. Hence we expect limited price tolerance at around current firm tariff rates. For as-available, non-firm service a higher tariff could be sustained since such service will only be sought in conditions where AGL's other options are constrained.

Origin Energy

<u>Prospective use of service</u>

Origin Energy has access to an extensive portfolio of gas production in the Surat/Bowen Basin region (both in its own right and through APLNG). A number of these sources are in locations close to RBP. However, as noted in relation to APLNG, for normal day-to-day operations, Origin has access to

[33] "AGL signs gas sales agreement with GLNG". AGL Media Release dated 24 December 2015.

dedicated infrastructure that negates any need to access RBP Western Haul service. All of the Origin Energy-operated exploration and production tenements in APLNG's Surat Basin and Bowen Basin (Comet Ridge) areas have good access to this dedicated infrastructure. The only Origin-operated tenements in the Surat Basin that are not dedicated to APLNG are those forming the Ironbark CSG project (ATP 788P, PCA 1 -3) which has been touted as a possible source of future domestic gas supply. Ironbark is not currently in production nor is there any announced development timetable for the project: according to Origin Energy's website it is "… in the exploration and appraisal stage".

Origin Energy has multiple alternative routes to direct gas from the Surat Basin to Wallumbilla should it need to do so to support its retail marketing activities (see below). We therefore see no reason why Origin Energy would be a user of Western Haul services on RBP.

<u>Alternatives to Western Haul service</u>

Origin Energy Retail has access to its own dedicated pipeline infrastructure that is capable of delivering gas to Wallumbilla. Specifically, it owns:

— (Through APLNG) PPL 143 which links the Spring Gully CSG field (on the Comet Ridge) to the Queensland Gas Pipeline (Jemena) which provides a transportation pathway to Gladstone and Wallumbilla.
— The Spring Gully to Wallumbilla Pipeline (PPL 90; 324mm, 12 inch, approx. uncompressed capacity 50 TJ/day)
— The Wallumbilla – Talinga – Darling Downs Power Station pipeline system (PPL 133, 134; 450mm, 18 inch, approx. uncompressed capacity 150 TJ/day).

These transport options represent a sunk cost to Origin. Given these alternatives, Origin would be unlikely to pay for Western Haul transport on RBP except in circumstances where it is unable, for operational reasons, to utilise its own dedicated infrastructure.

Origin could use RBP Western Haul service to move gas from the Peat field to Wallumbilla via the Scotia – Peat Lateral. However, Peat gas is currently sold into the Brisbane market and so any redirection of Peat gas to Wallumbilla would represent a subtraction of market volume from RBP Eastern Haul services. Furthermore, there is a pipeline connection from the Peat/Scotia gas fields to APLNG's main export pipeline that would allow Peat gas to be redirected to Gladstone without passing through Wallumbilla.

<u>Quantum of service</u>

Nil. It is difficult to conceive of a situation in which Origin Energy would make use of RBP Western Haul services.

<u>Demand profile</u>

Nil. It is difficult to conceive of a situation in which Origin Energy would make use of RBP Western Haul services.

<u>Price tolerance</u>

Not applicable.

EnergyAustralia

<u>Prospective use of service</u>

Nil. EnergyAustralia does not sell retail gas in the Queensland market and does not, to our knowledge, hold any upstream gas entitlements in the Surat/Bowen Basin region serviced by RBP.

Alinta Energy

<u>Prospective use of service</u>

Alinta Energy does not sell retail gas in the Queensland market. Alinta could potentially redirect gas from its Braemar power station operations, trading it at the Wallumbilla hub. However, this is accounted for in the Spot Market Trade usage (see below), and would in any case be a subtraction from assumed Eastern Haul volumes on RBP.

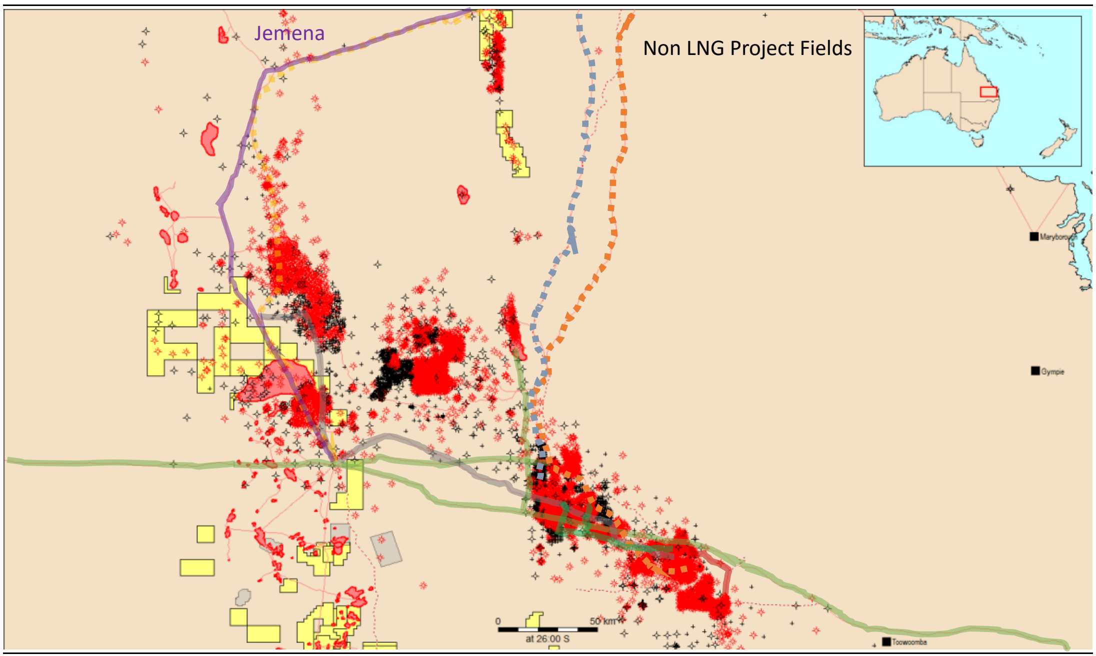
3. Other (non-LNG) gas producers

Prospective use of service

There are a limited number of gas exploration and production title holders in the Surat Basin region, proximate to the RBP, that are not energy retailers but that currently serve the domestic gas market, or have the potential to do so. One of these (Shell Arrow Energy) is involved in LNG production at Gladstone through the Shell QCLNG project, but also has domestic gas production operations that were supplying Swanbank E power station (and have now been on-sold). The other non-LNG exploration and production interests are shown in **Figure 7.7**.

Most non-LNG aligned exploration tenements lie to the north-northwest and south-southwest of Wallumbilla and are therefore not geographically located in positions where use of RBP Western Haul services could be advantageous. One exploration permit (ATP 889 Part, Stuart Petroleum) straddles the RBP some 10 km to the east of Wallumbilla. However that permit has only been tested with a single CSG well (Hawkins-1, drilled 2013) which was plugged and abandoned as a dry hole. There is currently, therefore, no current prospect of any gas production from this area.

FIGURE 7.7 OTHER (NON-LNG) PRODUCERS GAS DELIVERY INFRASTRUCTURE



SOURCE: ACIL ALLEN COMPILATION OF DATA FROM ENCOM GPINFO AND QUEENSLAND GOVERNMENT "QUEENSLAND GLOBE" DATA

The only non-LNG associated production that we have been able to identify that could, therefore, use the RBP Western Haul service is the Arrow Energy Kogan North and Tipton West area, located near Dalby in the eastern Surat Basin. Data published on the National Gas Services Bulletin Board shows that, since January 2014, gas injections into the RBP at the Kogan North delivery point have averaged around 6 TJ/day, and have not exceeded 12 TJ/day.

Alternatives to Western Haul service

The Kogan North and Tipton West fields were developed to supply the Swanbank E power station west of Brisbane, and so were previously transported east on RBP. Since closure of the Swanbank E power station, this gas has been sold to LNG project operators and/or gas retailers. If sold to LNG operators, the purchasers will have the various transportation options discussed in the sections dealing with LNG project alternative transport services. If sold to retailers (AGL, Origin) then this gas could be used to service their SE Queensland customer base or otherwise moved west using the transportation options discussed under the retail supplier heading.

Quantum of service

We assume that Arrow Energy, or the current purchasers of the Kogan North/Tipton West gas production (ex Swanbank E/Stanwell) may purchase up to 12 TJ/day of firm RBP Western Haul service in order establish the option of delivering this gas to Wallumbilla for onward shipment. There is a significant risk that this assumed capacity booking will not materialise, given the transport alternatives available to prospective purchasers of this gas.

Demand profile

12 TJ/day firm. We regard this as a generous allowance given that reliable service could be achieved with a mix of firm service at 6 to 8 TJ/day covering average levels of production, with the balance accessed on a non-firm basis to meet peak requirements when necessary.

Price tolerance

The assumed firm booking will provide an option in place of Eastern Haul delivery on RBP, or direct transfer into LNG upstream infrastructure. We therefore expect limited price tolerance at around current firm tariff rates.

4. Major domestic gas users

The fourth category of potential customers for RBP Western Haul service that we have identified are major gas users (direct contracting, rather than retail purchasers). Following closure of the BP Bulwer Island facility, which was supplied with gas from the Peat field—supply that we understand has now been redirected to APLNG—the only candidate shippers within this group are Swanbank E and Incitec Pivot.

Swanbank E redirection of gas would be from QGC Berwyndale (no RBP Western Haul service required in order reach Gladstone LNG plants, as previously discussed) or Arrow Surat (accounted for in "Other (non-LNG) producers).

Incitec Pivot redirection is currently speculative and would, in any case, be a subtraction from eastern haul volumes assumed in the Base Case.

We therefore see no prospect of use of RBP Western Haul service by current major domestic gas users that has not already been taken into account in the demand forecasts.

5. Spot market traders

Spot market traders looking to trade gas at the Wallumbilla Gas Supply Hub represent the final category of potential users of RBP Western Haul services. Most of the parties likely to participate in trading at the WGSH will be LNG project participants, gas retailers or independent gas producers and so will, to a large extent, have been captured in the preceding analysis. However, we conservatively assume that these parties might make use of RBP Western Haul services outside their normal transportation operations, *purely to facilitate WGSH trading operations.*

Prospective use of service

As discussed in Section 5.1 anyone wishing to trade at the WGSH must have access to the transportation services required to ensure that gas offered for sale can be delivered to the hub, and that gas purchased at the hub can be shipped out by the purchaser. RBP Western Haul services are therefore potentially useful for trading participants wishing to sell gas at the WGSH—even though, as previously discussed, most of the potential participants will have access to alternative means of transporting gas to Wallumbilla, often on a sunk cost basis.

Quantum of service and demand profile

The average volume of spot gas traded on the WGHS during 2014 (first year of operation) was 5.3 TJ/day, rising to an average of 9.7 TJ/day over the first half. The maximum volume traded on any day since market opening has been 60 TJ/day, with a high level of volatility evident (see further discussion in section 5.2). We therefore assume that:

- one or more parties will commit, in aggregate, to take 10 TJ/day of firm RBP Western Haul service in order to accommodate the average volume of trade on WGSH. This could, for example, comprise five different shippers reserving an average of 2 TJ/day each.
- one or more parties will use up to 50 TJ/day of non-firm RBP Western Haul service in order to meet peak day trading requirements on the WGSH. We further assume that the probability of this level of non-firm service being required on any given day will be moderate (between 10 and 25 per cent).

There is a significant level of risk in relation to this forecast, given that most trading participants would have other means of transport to deliver gas to the Wallumbilla hub.

Price tolerance

The assumed firm booking will provide back-up service to gas delivery via other means for the majority of trading participants. The alternative would be to utilise other transmission services. Hence we expect limited price tolerance at around current firm tariff rates. For as-available, non-firm service a higher tariff could be sustained since such service will only be sought in conditions where the trader's other options are constrained.

7.4 Conclusions regarding prospective demand for RBP Western Haul service

The results of the preceding analysis are brought together in **Table 7.1** to provide a consolidated summary of the prospective demand for RBP Western Haul Services.

TABLE 7.1 PROSPECTIVE DEMAND FOR RBP WESTERN HAUL SERVICE

Prospective Western Haul Service User	Firm	Non-firm peak	Non-firm probability	Comments
CSG LNG		120	0 -10%, use 5%	Any 1 of the 3 CSG LNG Projects could use all available West Haul capacity on rare occasions if normal supply routes are disrupted.
Shell QCLNG	0			
Shell Arrow	0			
APLNG	0			
Santos GLNG	0			
Energy Retailers				
AGL	10	90	0 - 2% use 1%	AGL's remaining net gas entitlements ex Berwyndale (after GLNG and Mt Isa sales) = 6 to 5 TJ/day assuming options were exercised, with some redraw entitlement under GLNG deal; primary carriage will be on existing BWP entitlements. Possible seasonal (winter) service. Could use 90 TJ/day non-firm service for GLNG and Mt Isa supply if BWP unavailable to meet GLNG deliveries.
Origin Energy	0	0		Origin has multiple alternative routes to direct gas to Wallumbilla.
Energy Australia	0	0		EA does not offer retail gas sales in Queensland and does not have upstream gas entitlements in the Surat/Bowen Basin region serviced by RBP.
Alinta	0	0		Alinta possible redirection of gas from Braemar accounted for in Spot Market Trade, and would in any case be a subtraction from assumed eastern haul volumes.
Other (non-LNG) producers	12			Kogan North injections to RBP at up to 12 TJ/d; allows for option to move this west. Could be taken up as a mix of firm and non-firm service.

Prospective Western Haul Service User	Firm	Non-firm peak	Non-firm probability	Comments
Major Domestic Gas Users	0	0		Swanbank E redirection of gas is from QGC Berwyndale (no WH service required) or Arrow Surat (accounted for in "Other (non-LNG) producers); Incitec Pivot redirection would be a subtraction from assumed eastern haul volumes.
Spot Market Traders	10	50	10% - 25%, use 18%	Average spot volume in 2016 was 9.7 TJ/day for first 7 months; maximum volume any day = 60 TJ/d. Most potential market participants have transport alternatives to deliver gas for trade at Wallumbilla.

SOURCE: ACIL ALLEN ANALYSIS

On this basis we see scope for firm capacity bookings for RBP Western Haul Service of totalling up to 32 TJ/day, comprising AGL retail (10 TJ/day, possible seasonal winter service); Arrow Kogan Creek/Tipton West (12 TJ/day to provide option of physical delivery at Wallumbilla); and 10 TJ/day in aggregate from spot market traders to ensure ability to deliver average levels of traded gas supply at WGSH.

With regard to non-firm (as-available, interruptible) services, we see scope for any of the three LNG projects to take all available Western Haul capacity on a short term basis to deal with operational imbalance issues. However, the frequency of such requirements will be low—we estimate between zero and 10 per cent probability on any given day, and assume 5 per cent for purposes of quantification. We consider this to be a generous allowance once the LNG projects achieve steady state operation, not least because of the opportunities that will exist for the three projects to co-operatively manage planned maintenance and similar activities, swapping gas between the projects as a primary means of dealing with temporary surplus production at any individual project.

AGL could use up to 90 TJ/day of interruptible service in the event of an outage on the BWP. However we assess the probability of such disruption to be very low; we have proposed a rate between zero and 2 per cent on any given day, and assume 1 per cent for purposes of quantification. We also note that this probability is much higher than the historical rate of service outage on BWP or other gas transmission pipelines in eastern Australia.

Spot market traders could use 50 TJ/day of interruptible service in order to cover the difference between average and historically observed peak levels of demand in the WGSH. We assess the likelihood of such usage on any given day as being moderate (10 to 25 per cent) and assume an 18 per cent probability for purposes of quantification.

On this basis, we can identify total demand for RBP Western Haul Services of up to:

— 32 TJ/day of firm service
— 16 TJ/day (probability weighted) of non-firm service.

Given the pipeline transport alternatives available to the majority of market participants, we see a significant risk that these levels of usage will not eventuate. We would regard any higher level of assumed uptake of RBP Western Haul service over the next access arrangement period as being highly speculative.

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8 CONCLUSIONS

Under Base Case assumptions, **annual eastbound throughput** on the RBP is expected to fall from a peak of about 61,800 TJ in 2013–14 (driven in part by elevated levels of gas use for power generation in the lead up to commissioning of LNG facilities in Gladstone) to about 32,800 TJ in 2016–17. This steep decline has been driven by a number of market developments: withdrawal of the Swanbank E combined-cycle gas turbine (CCGT) plant; closure of the BP Bulwer Island refinery and co-generation facility; and a reduction dispatch of gas-fired generation following commissioning of the Gladstone LNG plants.

Future eastbound throughput on the RBP is, however, highly dependent on the requirements of two major loads: Swanbank E power station and Incitec Pivot's Gibson Island fertiliser plant. There are significant uncertainties associated with both.

— In the case of Swanbank E power, the uncertainty relates to the timing of return to service of the station, which has been mothballed since December 2014.

— For Incitec Pivot, the key uncertainty is whether the plant will continue to operate beyond the term of its current gas supply arrangements.

These uncertainties result in a wide range of potential outcomes for throughput on the RBP. If Swanbank E remains off line and Incitec Pivot shuts down (our Low Case), throughput on the RBP will fall to around 20,000 TJ/a. On the other hand, if Swanbank E returns to service early—say late 2017—and Incitec Pivot continues to operate at current levels throughout the next access arrangement period (our High Case), then total throughput on RBP will rise to around 48,000 TJ/a.

In all three cases, annual eastbound throughput on RBP will fall significantly below historical levels.

The **demand for firm capacity** (that is, contracts for firm eastern haul services) on RBP will also decline as a result of the loss of the BP Bulwer Island load and the (temporary) loss of the Swanbank E load.

Under the Base Case assumptions the **peak demand** level for east-bound flow on the RBP is expected to drop by around 65 TJ/day, from 215 TJ/day to about 150 TJ/day. The Low Case Assumptions would see peak demand for east-bound flow fall further to around 115 TJ/day, while the High Case would see a recovery in east-bound peak demand from a low of about 150 TJ/day in 2016–17 to more than 230 TJ/day with a return to service of Swanbank E power station and increased use of RBP by other gas-fired generators.

The forecast **lower peak utilisation** rate for the RBP is likely to result in a shift in the service mix on the pipeline, with less demand for long-term firm service and more demand for short term and non-firm services.

We consider it unlikely that the operations of the **Wallumbilla Gas Supply Hub** will generate a significant demand for new or additional services on the RBP, but have assumed that there will be modest uptake of RBP Western Haul service to support trading activities.

The RBP is not a primary source of transport services for the **CSG LNG projects**, and experience to date does not provide any reason to expect that transportation services on the RBP will form a core part of the gas transportation strategy for any of the LNG projects. However the RBP could provide a number of "supporting services" that may be called on by the LNG project operators in certain circumstances including Western Haul services and short-term eastern haul transportation services.

Demand for **Western Haul services** on RBP has risen since the commencement of those services in mid-2015. However, much of this demand has been associated with transient seasonal (winter) demand in southern domestic markets and with LNG operational issues during commissioning.

Future demand for Western Haul services to supply gas to the domestic market is likely to be irregular and seasonal: for the most part it will not provide a basis for long-term firm transportation contracts but more likely for short-term arrangements.

LNG projects are likely to continue to use Western Haul services on the RBP from time to time, on a temporary basis, to deal with operational issues as they arise. However such requirements are unlikely to require long-term firm transport contracts. It is more likely that such service requests will be short-term and essentially opportunistic in nature, to deal with emergent issues, and will have service requirements dictated by the specific circumstances in which they are sought.

The total demand for RBP Western Haul Services that we can identify is:

— Up to 32 TJ/day of firm service
— Up to 16 TJ/day (probability weighted) of non-firm service.

Given the pipeline transport alternatives available to the majority of market participants, we see a significant risk that these levels of usages will not eventuate. We would regard any assumed uptake of RBP Western Haul service beyond these levels over the next access arrangement period as being highly speculative.

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