September 2016

roma to brisbane pipeline

access arrangement submission.

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contents

attachments

1-1	AER confidentiality template
3-1	Acil Allen Consulting, Roma to Brisbane Pipeline - assessment of demand for services for the access arrangement period 1 July 2017 to 30 June 2022
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4-3	RBP compressor operating philosophy
4-4	Queensland pipeline management plan
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5-3	Corporate IT capital expenditure project documents
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abbreviations

AA	Access Arrangement
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
AC	Alternate Current
ACCC	Australian Competition and Consumer Commission
ACN	Australian Company Number
AER	Australian Energy Regulator
AMP	Asset Management Plan
APA	APA Group
APTPPL	APT Petroleum Pipelines Pty Limited
AS	Australian Standard

CAPM	Capital Asset Pricing Model
CP	Cathodic Protection
CPI	Consumer Price Index
Cth	Commonwealth
DCVG	Direct Current Voltage Gradient
FEED	Front End Engineering and Design
GDP	Gross Domestic Product
GIS	Geospatial Information System
GJ	Gigajoule
IT	Information Technology
km	Kilometres
KP	Kilometre Point
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure
MDQ	Maximum Daily Quantity
MRP	Market Risk Premium
MS	Meter Station
Mt	Mount
National Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
NEGI	North East Gas Interconnector
NGL	National Gas Law
NGR	National Gas Rules
PMP	Pipeline Management Plan
PRS	Pressure Reduction Station
PTRM	Post Tax Revenue Model
RBP	Roma Brisbane Pipeline
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
TAB	Tax Asset Base
TJ	Terajoule
WACC	Weighted Average Cost of Capital

executive summary

The SE Queensland gas market has undergone significant change since the last revision to the Roma Brisbane Pipeline (RBP) access arrangement in 2012. The construction of three Liquefied Natural Gas (LNG) projects in Gladstone and the associated development of the coal seam gas industry has had a profound impact on the SE Queensland gas market.

This revised access arrangement acknowledges those changes to the market, and includes services to meet the needs of shippers in the new environment.

Services

This access arrangement makes two key changes to its Reference Services relative to the previous access arrangement. The RBP now offers:

- both Eastbound and Westbound Reference Services, to allow midstream gas to be shipped either towards Brisbane or towards the Wallumbilla Hub; and
- both Long Term Firm and Short Term Firm services, consistent with the demands of today's shippers.

The Long Term Firm service is a capacity reservation service, which is charged with a capacity-only tariff over the longer term of the contract. The Short Term Firm service is only charged for the term of the capacity reserved (as little as one day).

Capex and capital base

The RBP regulatory capital base at 1 July 2017 is forecast to be $451m.

Capital expenditure over the previous period (2012-17) included emergency flood and washout repairs, and capital expenditure to allow bi-directional gas transportation.

Looking forward, the forecast capital expenditure is driven by the age of the pipeline and the scope of urban encroachment on the right-of-way. There is no forecast capital expenditure proposed to expand the capacity of the pipeline.

Rate of return

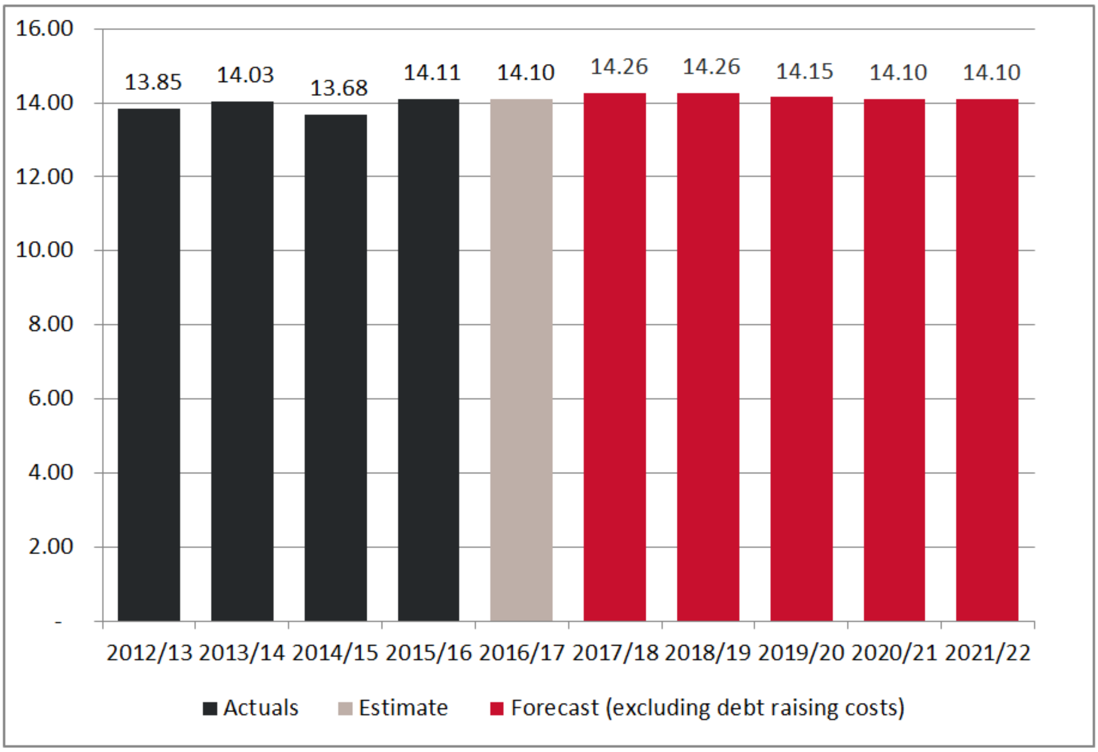
This access arrangement revision proposal applies the AER Rate of Return Guideline to determine the appropriate rate of return. However, this access arrangement revision proposal includes more appropriate parameter values, as discussed in more detail in Chapter 7.

The proposed revised access arrangement includes a post-tax cost of equity of 8.40 per cent, a pre-tax cost of debt of 7.26 per cent, for a post-tax vanilla WACC of 7.72%.

Operating expenditure

Notwithstanding the changes in the underlying market, the RBP operating environment has been relatively stable in recent years, and in line with the AER's approved opex in the previous access arrangement period. Forecast opex has been based on trending of historical opex, averaging approximately $14.2 million per year.

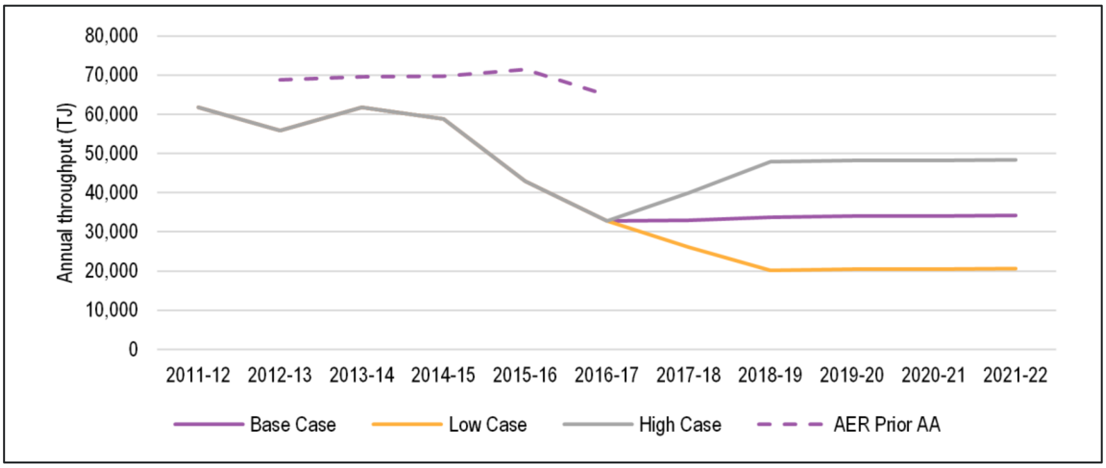
Figure ES.1: total operating expenditure historic and forecast ($m 2016/17)



Demand forecast

Actual throughput has fallen significantly short of 2012-17 forecast amount, and is forecast to remain at subdued levels.

Figure ES.2: Historical and forecast RBP throughput



The decline over the 2012-17 access arrangement period has been driven by the 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 reduced dispatch of gas-fired generation following commissioning of five LNG liquefaction trains in Gladstone over the period December 2014 to May 2016.

The forecast outcomes will be determined by a small number of binary decisions regarding continued operation or closure of individual large loads (Swanbank E, Incitec Pivot Gibson Island).

Forecast revenue outcome

	2017-18	2018-19	2019-20	2020-21	2021-22
Return on capital	34.84	36.44	37.19	37.33	38.10
Return of capital	6.41	7.27	5.70	-0.67	-0.59
plus operating and maintenance	14.84	15.19	15.43	15.72	16.08
plus revenue adjustments	1.73	0.00	0.00	0.00	0.00
plus net tax allowance	2.53	2.48	1.81	0.72	0.77
Total	60.36	61.38	60.13	53.10	54.36
Smoothed revenue path	50.69	54.45	58.48	62.82	67.48
X factors tariff revenue (%)		-5.00%	-5.00%	-5.00%	-5.00%

Tariff outcome

This proposed revise access arrangement proposes a tariff for Long Term Firm capacity of $0.6944 per GJMDQ/day commencing 1 July 2017. The Short Term Firm tariff is calculated as a multiple of 1.66 times the posted Long Term Firm tariff.

1 introduction

This submission provides supporting information for APT Petroleum Pipelines Pty Limited (APTPPL)'s proposed revision of the Access Arrangement for the Roma Brisbane Pipeline (RBP) to be effective from 1 July 2017.

In accordance with the requirements of section 132 of the National Gas Law (NGL) and section 43(1) of the National Gas Rules (NGR), APTPPL has provided to the Australian Energy Regulator (AER) with this submission:

- A proposed revised access arrangement in respect of the RBP;
- An Access Arrangement Information document; and.
- A submission in support of the proposed amendments to the RBP access arrangement (this document and attachments).

Together these documents make APTPPL's access arrangement revision proposal.

1.1 Information required by Regulatory Information Notice

On 4 July 2016, the AER served on APTPPL a Regulatory Information Notice (RIN) under Division 4 of Part 1 of Chapter 2 of the NGL. The RIN specifies information to be provided to the AER by APTPPL in its access arrangement revision proposal, and the form of that information.

This submission, along with the access arrangement proposal, access arrangement information, and accompanying financial models, provides information in satisfaction of the requirements placed on APTPPL in the RIN.

The RIN also requires that APTPPL submit to the AER an Index of Information outlining where the information to be provided under the RIN is contained in the access arrangement revision proposal. This Index of Information can be found at Appendix C to this submission.

1.2 Basis of information in the access arrangement revision proposal

Rule 73 states that:

(a) Financial information must be provided on:

(i) a nominal basis; or

(ii) a real basis; or

(iii) some other recognised basis for dealing with the effects of inflation.

(b) The basis on which financial information is provided must be stated in the access arrangement information.

(c) All financial information must be provided, and all calculations made, consistently on the same basis.

Unless otherwise stated, all information in the access arrangement revision proposal is provided in real 2016/17 dollars. Past values are brought to this basis using the Consumer Price Index (CPI) all groups, eight capital cities average March over March published by the Australian Bureau of Statistics (ABS).

1.3 Corporate structure

APT Petroleum Pipelines Pty Limited (APPPL) is wholly owned by APT Pipelines Limited. This structure is shown in Figure 1.1 below.

Figure 1.1: APTPPL corporate ownership structure

Company	Activity
APT Pipelines Limited ACN 009 666 700 (Australian Public Company)	Parent investment company for Australian Pipeline Trust.
Owns 100% of:	
Sopic Pty Limited ACN 010 851 288 (Australian Private Company)	Owns shares in APT Petroleum Pipelines Holdings Pty Limited.
Owns 100% of:	
APT Petroleum Pipelines Holdings Pty Limited ACN 009 738 489 (Australian Private Company)	Owns shares in APT Petroleum Pipelines Limited.
Owns 100% of:	
APT Petroleum Pipelines Pty Limited ACN 009 737 393 (Australian Private Company)	Owns and operates Roma to Brisbane Pipeline including Peat Lateral

APTPPL is both owner and operator of the RBP. APTPPL is not a local agent of a service provider of the pipeline as defined by the NGL, nor does it act on behalf of another service provider of the pipeline as defined by the NGL.

APTPPL's sole business is the ownership and operation of the RBP. APTPPL has no associate contracts in place relevant to the delivery of pipeline services for the RBP.

1.4 Pipeline history and characteristics

The RBP was commissioned in its original configuration in 1969. It now consists of a mainline, which is both compressed and looped, and three lateral pipelines; Peat lateral, connecting it to CSM gas sources near Peat and Scotia, Swanbank Lateral, feeding into Swanbank Power Station and Lytton Lateral, supplying the Caltex Refinery. The mainline is approximately 440 km long with about 30 km of its length running through Brisbane to Gibson Island.

The original 410 km section from Wallumbilla to Ellengrove is 273 mm in diameter (DN250). This section is looped with a 406 mm diameter pipeline (DN400). The looping was carried out in several stages, between 1988 and 2002, after the original line had been fully compressed.

The Swanbank lateral was completed in 2001 and is 38 km long with a current capacity 52TJ/day. The Peat lateral was completed in the same year (the Scotia extension was completed in 2003) and is 121 km long with a current nominal capacity of 74 TJ/day. The Peat lateral became part of the covered pipeline on 1 January 2006 after APTPPL elected, following consultation with the ACCC (as permitted by its access arrangement), for it to be covered. The 6km Lytton lateral was completed in 2010.

The pipeline originally supplied the Brisbane area with gas from Surat Basin fields close to Roma. In 2001 and 2002 the RBP was extended via the Peat Lateral to enable Coal Seam Methane (CSM) from the Peat and Scotia gas fields to be supplied into south-east Queensland. The RBP also connects with the Queensland Gas Pipeline (QGP), which runs from Wallumbilla to Rockhampton (via Gladstone). This allows Wallumbilla to function as a hub for the supply of gas in Queensland.

There are six compressor stations along the length of the pipeline. Those at Yuleba (retired), Kogan and Oakey serve the original pipeline while those at Condamine, Dalby (Unit 1) and Gatton (all retired) serve the looped pipeline. A Centaur C50 compressor was installed in 2012 at Dalby (Unit 2), which serves the DN400 pipeline.

The expansions of RBP capacity and the construction of the Lateral pipeline occurred in response to market growth, and were underpinned by contracts negotiated with third parties such as producers, power stations, gas utilities and major industrial customers. The RBP currently receives gas from numerous receipt points and delivers gas to numerous delivery points. Additional receipt and delivery points have been added from time to time.

Key dates in the RBP's development are shown below.

Table 1.1: RBP key dates

Date	Event
1965	Incorporated as Associated Pipelines Limited.
1969	Pipeline construction completed. Associated Pipelines Limited sells bundled gas and pipeline services and has related ownership with upstream gas fields.
1982	Dalby (Unit 1) Compressor installed, Kogan Compressor installed.
1983	Oakey Compressor installed.
1984	Condamine Compressor installed.
1985	Yuleba Compressor installed.
1986	Gatton Compressor installed.
1987	Joint Venture established. 85% interest held by Associated Pipelines Limited. 15% interest sold to I.O.L. Petroleum Limited.
1988	Looping 1 completed. Associated Pipelines Limited name changed to CSR Petroleum Pipelines Limited. Acquisition of CSR Petroleum Pipelines Limited by The Australian Gas Light Company, as part of a larger acquisition of CSR's oil and gas production and transportation operations. This included the acquisition of gas production interests in Qld. CSR Petroleum Pipelines Limited name changed to AGL Petroleum Pipelines Limited.
1990	Looping 2 completed.
1993	Upstream gas production interests sold by AGL.
1997	IOL Petroleum Limited change of name to Interstate Pipelines Pty Limited.
1998	Looping 3 completed.
2000	Looping 4 completed. AGL divestment of its pipelines group includes AGL Petroleum Pipelines Limited through float of Australian Pipeline Trust. AGL Petroleum Pipelines Limited change of name to APT Petroleum Pipelines Limited (APTPPL).
2001	Peat Lateral and Swanbank Lateral completed Acquisition of Interstate Pipeline's 15% interest by APTPPL.

Date	Event
2002	Looping 5 & 6 completed.
2003	Scotia extension to Peat Lateral completed.
2010	Lytton Lateral completed.
2012	RBP8 expansion completed, consisting of looping in the metro section from Mount Gravatt to SEA, MAOP upgrades, and installation of a Centaur C50 compressor at Dalby.

Management and operation of the RBP includes:

- Scheduling and control of the gas haulage through the pipelines through control rooms
- Planning, scheduling, prioritising of labour, materials and supplies required to operate and maintain all assets
- Providing operational input into asset management, commercial development, regulatory management and compliance activities relating to the assets under management
- Providing emergency response, safety management and repair response for APTPPL's assets
- Planning and delivery of small scale asset capital replacement and development projects
- Providing support in construction and commissioning of new projects

1.4.1 *Urbanisation and encroachment*

In accordance with AS2885.3, pipelines must be designed to specifications determined by, amongst other things, the existing, surrounding land use. Existing land use determines key pipeline specifications such as depth of coverage and wall thickness of pipeline.

The failure of a high pressure pipeline can impact an area several hundreds of metres from a pipeline. A frequent cause of pipeline failure worldwide is caused by construction or maintenance activities. Australian high pressure pipelines are designed, operated and maintained to mitigate threats that have the potential to cause failure.

The existing RBP pipeline was designed taking into account the plans that existed at the time it was constructed. When commissioned in 1969, the RBP had been constructed through mainly rural or semi-rural areas with low density population. With population growth, development and transformation of land use, the urbanisation of south east Queensland continues to impact on pipeline operations.

Although APTPPL must comply with changing planning and technical regulations, there is currently no requirement on local governments or developers to ensure that APTPPL are consulted with respect to the potential impacts of land use changes or developments in the vicinity of the pipeline and its operation. This has resulted in inappropriate planning outcomes such as the construction of residential housing adjacent to high pressure pipeline easements.

With these changes come increased public encroachment upon the pipeline right of way, resulting in increased operations costs through increased Dial Before You Dig (DBYD) inquiries, observation of external party works, patrolling costs and public education initiatives.

1.5 Changes to the access arrangement

APTPPL has made very few changes to the access arrangement relative to that in place for the 2012-17 access arrangement period. The changes reflect:

- The removal of the directionality of the Reference Service;
- Introduction of the Short Term Firm Reference Service;
- Amendment to the Queuing Requirements to implement an auction for spare capacity.

There are minor consequential changes to the Terms and Conditions resulting from these changes.

A summary of the revisions to the main body of the access arrangement, and the reasons for those changes, are set out in Attachment A.

1.6 Access arrangement terms and conditions

APTPPL is owned by the APA Group, which also owns a number of other regulated and unregulated gas assets across Australia. Over time, APA Group has developed and implemented a standard form Gas Transportation Agreement across the all assets in the Group, which is also reflected in the terms and conditions of various access arrangements for covered pipelines.

The Terms and Conditions in this proposed revised access arrangement are therefore largely the same as in the previous approved AER-access arrangement, with consequential changes arising from the changes in service definition and queuing as discussed above.

A summary of any changes to the terms and conditions, as well as reasons for the variations, is provided in Appendix B to this submission.

1.7 Other access arrangement elements

1.7.1 Revisions submission and commencement dates

APTPPL proposes a five year access arrangement period. Consistent with Rule 50(1), APTPPL proposes to include an access arrangement revisions submission date of 1 July 2021. This date provides the AER with a 12 month revision period, consistent with the general rule.

1.7.2 Extensions and Expansions

Rule 104 specifies that the extensions and expansion policy must state whether the applicable access arrangement will apply to incremental services provided as a result of a particular extension or expansion.

APTPPL does not propose any changes to the Extensions and Expansions Policy from that currently approved by the AER.

1.7.3 Queuing policy

APTPPL proposes to move from a first-come first-served queuing policy to a public auction process for spare Existing and Developable Capacity. This is discussed in more detail in section 11.2.

1.7.4 *Capacity Transfer*

As required under the Rules, APTPPL has included capacity transfer requirements in the access arrangement. These requirements have not been revised since the last access arrangement.

The capacity transfer requirements in the APTPPL access arrangement provide for:

- The transfer of a User's contracted capacity by subcontract to a third party without requiring APTPPL's consent; and
- Other assignments of contracted capacity may be made with the consent of APTPPL, subject to payment of APTPPL's costs associated with the transfer and compliance with APTPPL's reasonable commercial and technical conditions, the nature of which are described in the access arrangement.

1.7.5 *Changing receipt and delivery point*

As required under Rule 106, APTPPL's access arrangement includes provision for the change of receipt and delivery points by users. These requirements have not been revised since the last access arrangement.

1.7.6 *Reference services*

Rule 101 requires a Full Access Arrangement to contain a statement of reference services:

> *(1) A full access arrangement must specify as a reference service:*
>
> > *(a) at least one pipeline service that is likely to be sought by a significant part of the market; and*
> >
> > *(b) any other pipeline service that is likely to be sought by a significant part of the market and which the AER considers should be specified as a reference service.*

Consistent with the previous AA, the Long Term Firm Reference Service defined by the revised AA is a non-interruptible service for the receipt, transportation and delivery of gas through any length of the Pipeline. However, this access arrangement revision proposal removes the requirement that the gas transportation must be in the direction from Wallumbilla or Peat to Brisbane.

The Long Term Firm Reference Service is provided at the Long Term Firm Reference Tariff. The Long Term Firm Reference Service is a capacity reservation service, for which a capacity tariff is charged.

The Long Term Firm Reference 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.

This proposed revised access arrangement also features a second Reference Service, a Short Term Firm Reference Service. The components of the service are largely the same as the Long Term Firm Service. Capacity is reserved under this service only for the shorter term of the Short Term Service contract requested by the shipper (as little as one day).

APTPPL also offers Negotiated Services on the pipeline.

1.7.7 *Reference tariffs*

Rule 48(1)(d)(i) requires the full AA to specify the Reference Tariff for each Reference Service.

Reference Tariffs are developed according to the requirements of the Rules in chapter 10.

A change from the previous access arrangement is that the tariff levied for the Long Term Firm service is now charged as a 100 per cent capacity charge. The new tariff for the Short Term Firm service is charged as a 100 per cent capacity charge. As developed in chapter 10, the Short Term Firm capacity charge is calculated as a multiplier of the Long Term Firm capacity charge.

Consistent with the previous AA, the User may also be required to pay the following charges:

(a) Overrun Charge;

(b) Imbalance Charge;

(c) Daily Variance Charge; and

(d) Charges in respect of Receipt Stations and Delivery Stations;

As set out in the proposed revised AA.

2 services

This Access Arrangement proposes two Reference Services:

- a Long Term Firm Service; and
- a Short Term Firm Service.

2.1 Rule requirements

The National Gas Rules (NGR) require a full access arrangement to specify at least one Reference Service:

> *101 Full access arrangement to contain statement of reference services*
>
> *(1) A full access arrangement must specify as a reference service:*
>
> *(a) at least one pipeline service that is likely to be sought by a significant part of the market; and*
>
> *(b) any other pipeline service that is likely to be sought by a significant part of the market and which the AER considers should be specified as a reference service.*
>
> *(2) In deciding whether to specify a pipeline service as a reference service, the AER must take into account the revenue and pricing principles.*

2.2 Background

The current RBP AA includes a single Reference Service: Firm Full Forward Haul. This is a service for eastbound gas transportation (Wallumbilla or Peat to Brisbane) over any or all of the length of the RBP. Tariffs are derived wholly on the basis of the forecast demand for this service.

In 2015, the RBP became bidirectional - APTPPL secured an amendment to the pipeline license and completed works to allow westbound gas flows on the RBP, in the direction from Brisbane or Peat to Wallumbilla. These works included pipe work to connect the RBP to the Wallumbilla Hub, and metering equipment to enable the flow of gas to be measured in either direction.

As discussed in section 5.5, APTPPL considers this investment to be conforming capital expenditure in accordance with the provisions of Rule 79, and is therefore included in the regulatory capital base.

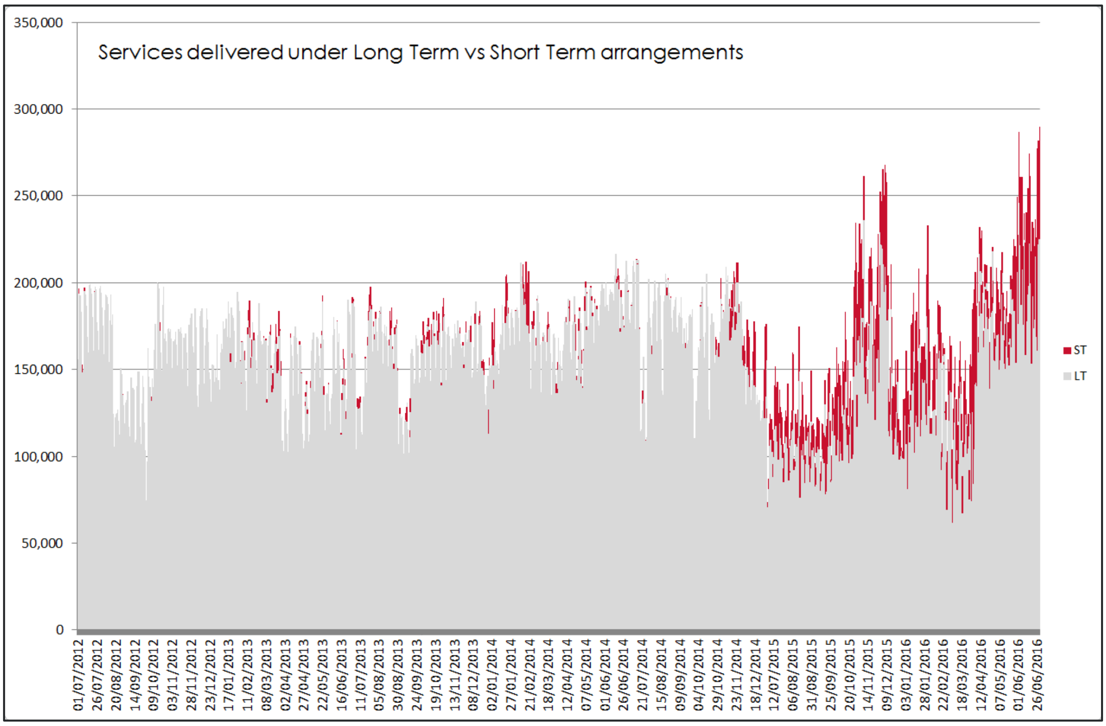
Consistent with the National Gas Law (NGL) definition:

> *pipeline service means—*
>
> *(a) a service provided by means of a pipeline, including—*
>
> > *(i) a haulage service (such as firm haulage, interruptible haulage, spot haulage and backhaul); and*
> >
> > *(ii) a service providing for, or facilitating, the interconnection of pipelines; and*
>
> *(b) a service ancillary to the provision of a service referred to in paragraph (a),*
>
> *but does not include the production, sale or purchase of natural gas or processable gas*

APTPPL considers the Westbound Service to be a pipeline service. As discussed below, APTPPL proposes to include the Westbound Service in the definition of the Reference Service.

As the dynamics of the SE Queensland gas market have changed, APTPPL has recently seen increased demand for pipeline services to be provided on a short term, often on as little as a day-ahead basis, particularly for Westbound services (see section 3.6).

Figure 2.1: RBP services delivered under Long Term Firm vs Short term arrangements



While short term services have not historically been demanded by a significant portion of the market, APTPPL is of the view that there is scope for a Short Term Firm Service to be demanded by a significant portion of the market in the upcoming access arrangement period.

APTPPL therefore proposes to nominate a Short Term Firm Service as a Reference Service.

2.3 The Reference Services

2.3.1 *Firm Service*

The Firm Service as defined in the current Access Arrangement is:

> *The Firm Service is a service for the receipt, transportation and delivery of Gas through any length of the Covered Pipeline in the direction from Wallumbilla or Peat to Brisbane.*

APTPPL considers that this service continues to be demanded by a significant portion of the market. However, as discussed above, the bidirectional nature of the RBP means that a Westbound Service should also be incorporated in the definition of the Reference Service. APTPPL proposes to accomplish this by removing the reference to the direction of flow from the definition of the Reference Service:

> *The Firm Service is a service for the receipt, transportation and delivery of Gas through any length of the Covered Pipeline.*

This definition applies equally to the Long Term Firm Service and the Short Term Firm Service.

2.3.2 *Long Term Firm Service*

The key features of the Long Term Firm Service, as specified in more detail in the Terms and Conditions, include:

- At the commencement of the Transportation Agreement the User will be required to establish for each Contract Year a Firm Maximum Daily Quantity (MDQ) and a Firm Maximum Hourly Quantity (MHQ) which fairly reflect the User's expected requirements;
- The term of the Long Term Firm Service will be three years from the commencement of the Firm Service or such longer period ending on an anniversary of the commencement of the Firm Service as the User elects;
- A Capacity Charge is payable for each day, calculated as the product of the Long Term Firm Capacity Tariff and the Firm MDQ (expressed in GJ) specified in the Transportation Agreement.
- Long Term Firm capacity can be traded under the Access Arrangement Capacity Trading provisions. Queuing provisions also apply.
- In the event of a need to curtail services, nominations under the Long Term Firm Service retain priority over those under other Services;
- Other charges (such as overrun charges) are payable as specified in the Terms and Conditions.

2.3.3 *Short Term Firm Service*

The Short Term Firm Service is a new service, recognising the changing dynamics in the SE Queensland gas market.

The features of the Short Term Firm Service are the same as the Long Term Firm Service, except that the Term of the contract for the Short Term Firm Service is less than that required for the Long Term Firm Service. The contract for the Short Term Service can be for as little as one day.

Like the Long Term Firm Service, the Short Term Firm Service is a capacity service, and requires the shipper to establish its requirements for the term of the contract. Like the Long Term Firm Service, the Service Provider undertakes to hold capacity available for the shipper's use as nominated; a Capacity Charge is payable for each day, calculated as the product of the Short Term Firm Capacity Tariff and the Firm MDQ (expressed in GJ) specified in the Transportation Agreement.

The Short Term Firm Service ranks equally with the Long Term Firm Service for scheduling and curtailment purposes. The Access Arrangement Capacity Trading and Queuing provisions do not apply to the Short Term Firm Service.

APTPPL submits that these two Services are services that "likely to be sought by a significant part of the market" and should be classified as Reference Services in accordance with Rule 101(1)(a).

Moreover, in APTPPL's experience, there are no other Services that are "likely to be sought by a significant part of the market" that would qualify for classification as Reference Services under Rule 101(1)(b).

3 pipeline demand and utilisation

This access arrangement features a forecast level of demand of 200 TJ/day, comprised of a combined demand for Eastbound Services and Westbound Services.

3.1 Context

Built in 1969, the RBP is one of several pipelines in the Surat-Bowen coal seam gas region. The pipeline was built, and expanded over the years, to bring gas from the gathering lines around Wallumbilla to industrial, commercial and residential users in the Brisbane area.

The RBP has always been an "open access" pipeline, and has historically served its customers under long term bilateral contracts. These contracts tended to match the users' needs for long term certainty in gas supply, and often aligned with the term of long term gas supply arrangements.

Historically, gas demand on the RBP has been quite stable, with pipeline capacity largely reserved through long term contract.

In the last 10 years, the coal seam gas fields in the Surat-Bowen basin have undergone rapid development, principally to support the demands associated with the development of liquefied natural gas (LNG) export operations at Gladstone. While the three LNG proponent groups have developed independent upstream production, processing, and transportation systems that do not rely on the RBP to bring gas to their production facilities, they have had a profound effect on Australia's gas markets, and the Queensland gas market in particular.

The Queensland gas market has seen a number of key changes:

- some stable industrial load has dropped off the system, notably the closure of the BP Bulwer Island Refinery;
- some electricity generation load has chosen to sell their gas entitlements rather than generate electricity, notably the mothballing of the Swanbank E power station; and

- the demand on the pipeline has become much more volatile, resulting from sharp swings in gas prices (particularly in relation to electricity prices) as generators take advantage of low cost LNG ramp gas to opportunistically generate electricity.

APTPPL has sought the assistance of market expert ACIL Allen Consulting to advise on the forecast load and demand over the 2017-22 access arrangement period. ACIL Allen's report is included in this submission as Attachment 3.1.

3.1.1 Drivers for pipeline demand

In attempting to forecast the demand for pipeline services, it is important to understand the nature and drivers of that demand. In particular, it may be easiest to understand the nature of the demand for the Westbound service by contrast to the demand for the Eastbound service.

The original development of the RBP, to provide the Eastbound service, reflects a symbiotic relationship between producers, pipeliner and users:

- A user (generally a foundation shipper), before investing in fixed, immovable plant with limited alternative use for an energy-intensive process (for example a brick works, a glass works or a brewery), needs confidence that it will be able to secure reliable gas supply over the long term life of its manufacturing facility, so that it can earn a return on and of its capital over the life of the asset.
- Before investing in fixed pipeline assets, the pipeliner needs confidence that the user will continue to take gas over the life of the pipeline so that the pipeliner can earn a return on and of its capital over the life of the pipeline.
- Before investing in developing gas-producing geological reserves, the producer needs confidence that the user will buy that gas over the long term life of the reserves, so that the producer can earn a return on and of its exploration and development expenditure over the life of the reserves.

Each of these parties relies on the long term commitments of the others to be able to finance its investment in plant, pipeline or reserves, respectively.

Importantly, none of them can hold the others to ransom without undermining its own commercial interests.

This symbiotic relationship has underwritten productive plant and pipeline development throughout Australia and the world for many years.

It is also relevant to note that the demand for gas is a derived demand. Users do not seek gas for its own sake, but rather for its value as an input to the productive process for another product (bricks, bottles, beer, etc).

The fundamental difference in the drivers of demand for the RBP Eastbound versus the Westbound service is that, unlike the eastern end of the RBP, there is no productive plant at the western end of the RBP.

Where the forecast demand for gas pipeline services at the eastern end of the RBP can be estimated based on the level of economic activity of the productive plant (the number of bricks or bottles to be made, the amount of beer to be brewed), there is no similar foundation for the demand for gas pipeline services at the western end of the RBP.

Rather, the demand for gas transmission services to the Wallumbilla Hub will depend entirely on gas price differentials between the various sources of gas delivering into the Hub. If the price of gas at the Wallumbilla Hub is attractive on a particular day, perhaps as a result of a shortage to meet LNG delivery requirements or a cold snap in southern markets, there will be a demand for Westbound services on the RBP to take advantage of that attractive price.

In short, it will be gas portfolio management and trading that will drive the demand for RBP Westbound services, not gas demand for productive use.

In this regard, it is relevant to note that the RBP is but one of many pipelines that can bring gas from the Queensland CSM fields to the Wallumbilla Hub for trading.

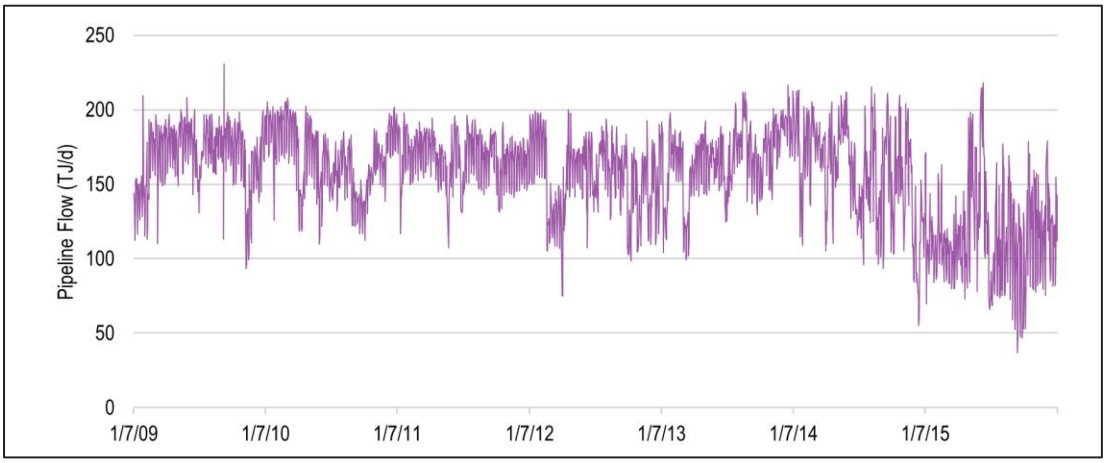
The demand for the RBP Westbound service is therefore likely to be variable and unpredictable, reflecting the speculative nature of the underlying trade. This opportunistic demand pattern does not lend itself to firm gas transportation commitments, and accordingly it is unlikely that many shippers that would seek the RBP Westbound service would be prepared to enter into Longer Term Firm capacity contracts for the provision of that service.

APTPPL therefore expects that most of the demand for the Westbound service would be provided on a Short term basis. In a regulatory context,[1] this presents a genuine revenue risk to APTPPL as service provider, and accordingly it will be important to exercise caution in forecasting any level of demand for the Westbound service.

3.2 Historical demand and utilisation

Even as late as the 2012-17 access arrangement review, the RBP was characterised as serving a stable market with slow, incremental growth. However, this has changed over recent years.

Figure 3.1: RBP historical demand (Eastbound)



Source: ACIL Allen Consulting Figure 3.1, from AEMO Bulletin Board data.

As can be seen from Figure 3.1, the RBP historical demand was relatively stable, ranging steadily in a band between 150 and 200 TJ/day. The impact of the changes to the Queensland gas market can be observed from mid-2013, when gas demand became more variable. By the end of June 2016, gas demand had declined and demand has become much more volatile from day to day.

Information relating to historical demand is shown in Table 3.1.

[1] In particular, in the context of s24(2) of the *National Gas Law*.

Table 3.1: RBP historical flow data

	Annual Throughput (TJ/year)	Average Throughput (TJ/day)	Peak Demand (TJ/day)	Load Factor[2]
2009–10	61,509	169	231	73%
2010–11	60,911	167	208	80%
2011–12	61,290	167	198	84%
2012–13	56,537	155	200	78%
2013–14	61,120	167	217	77%
2014–15	57,776	158	216	73%
2015–16	42,448	116	218	53%

Source: ACIL Allen Consulting, Table 3.1, APA analysis.

The decline in demand reflects some degree of slowdown in industrial activity in the Brisbane region, but in particular the November 2014 "mothballing" of the Swanbank E power plant and the mid-2015 closure of the BP Bulwer Island refinery.

The increased volatility of the load is primarily caused by the ramp-up of coal seam gas production to prove reserves in advance of the startup of the Gladstone LNG facilities. During this period, low-cost gas flooded the market, some of which was used in out-of-merit-order electricity generation (see ACIL Allen Consulting, section 4.1.1). A key question for load forecasting purposes is whether the load will stabilise once the LNG facilities have reached steady state operations.

Full disclosure of minimum, maximum and average demand by receipt and delivery point is provided in the Access Arrangement Information, in accordance with Rule 72(1)(a)(iii)(A) and (B).

[2] The load factor is a measure of the relationship of the average demand to peak demand, calculated as Average day / Peak day. A higher load factor reflects a "flatter" load profile, and a low load factor reflects a "peaky" load profile.

3.3 Historical demand by customer class

The RBP Eastbound[3] serves three distinct types of users:

- Large industrial users, who purchase gas from producers and contract directly with the pipeline for gas transportation;
- Retail users, who buy their gas as a delivered product through their retailer of choice. This class incudes the domestic and commercial users, as well as the smaller industrial consumers connected through the distribution networks; and
- Electricity generators.

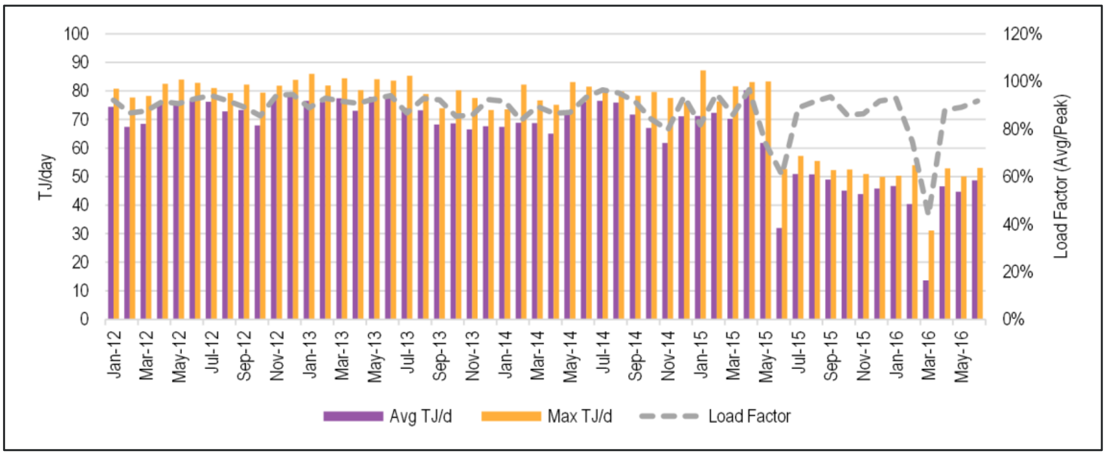
Each of these classes of user places different demands on the system, according to their needs. Each class, and their historical consumption patterns, are discussed below.

3.3.1 Industrial users

Industrial users are those that use gas as an energy source or as a feedstock in a productive process. These users generally have significant investment in fixed productive plant with limited alternate use, and are therefore most interested in a secure and reliable gas supply. These shippers tend to book firm capacity to meet their maximum demand, acknowledging that some of this reserved capacity may go unutilised on some days.

[3] RBP "westbound" services became available in October 2015, and are discussed in the context of the forecast load.

Figure 3.2: Industrial customers: Historical monthly, average and peak load



Source: ACIL Allen Figure 3.3. Analysis of APA meter data.

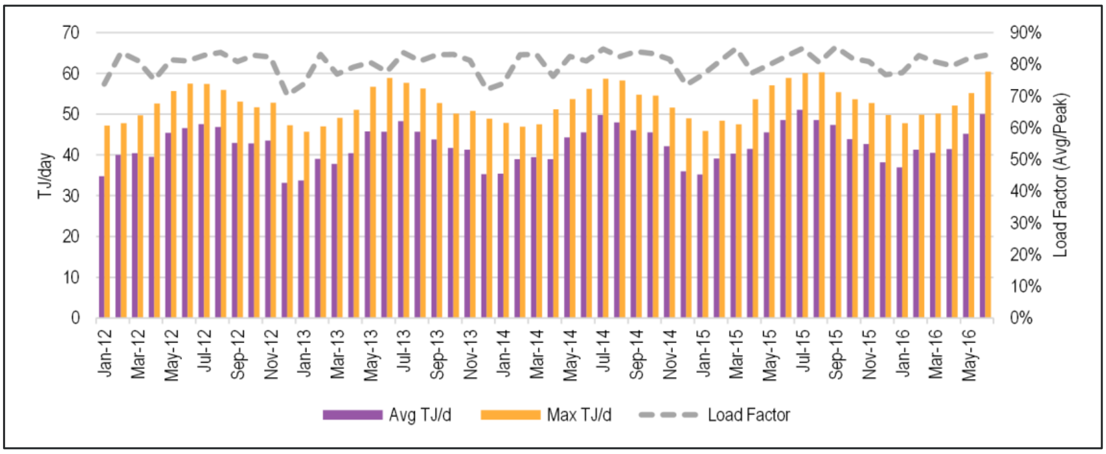
As can be seen from this chart, industrial use had historically been very steady, with a high load factor. This dropped off abruptly in mid-2015 with the closure of the BP Bulwer Island refinery. (June 2015 and March 2016 reflect temporary shutdowns at other large industrial plants). The BP Bulwer Island refinery accounted for 35 TJ/day of reserved capacity in the previous access arrangement period.

While the load factor remains quite high, the peak demand of this class has fallen from a historical average of approximately 80 TJ/day to about 50 TJ/day today.

3.3.2 *Retail users*

The retail class includes domestic, commercial and small industrial loads served from the distribution networks.

Figure 3.3: Retail customers: Historical monthly, average and peak load



Source: ACIL Allen Figure 3.8. Analysis of APA meter data.

This class shows some degree of seasonal variation, although this is limited by the temperate Brisbane climate. The load of this class has been relatively stable, showing a pattern of slow organic growth over time.

The monthly load factor is quite high, reflecting only minor variations between consumption between the average day and peak day in a given month.

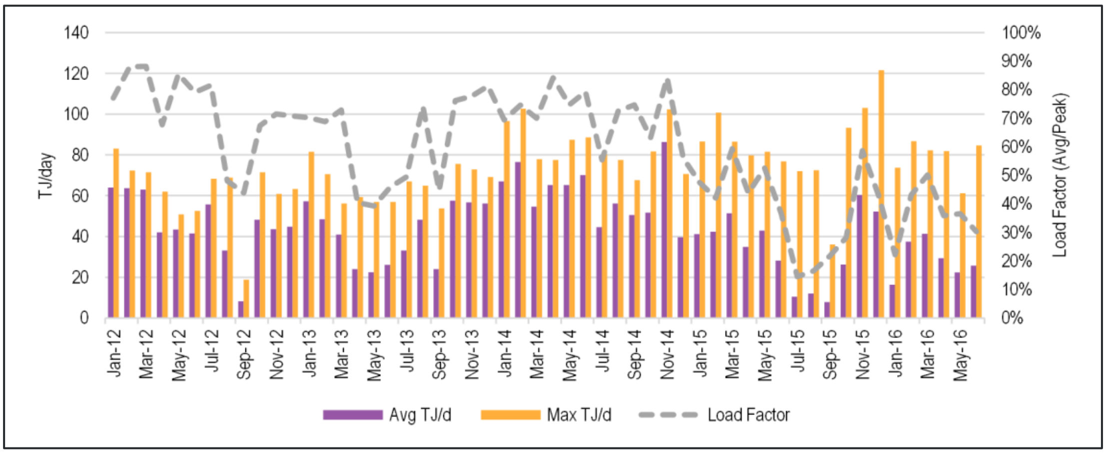
3.3.3 *Electricity generators*

There are three gas-fired power generators that take supply from the RBP:

- Oakey power station (ERM Power, 332 MW, OCGT);
- Swanbank E power station (Stanwell Corporation, 385 MW, CCGT); and
- Braemar power stations 1 (Alinta) and 2 (Arrow Energy), 952 MW combined, OCGT.

While Oakey and Swanbank E are reliant on the RBP for their gas supply, the Braemar power stations have alternate gas supply arrangements, and take only a small portion of their gas supply from the RBP.

Figure 3.4: GPG customers: Historical monthly, average and peak load



Source: ACIL Allen Figure 3.15. Analysis of APA meter data.

This chart clearly shows that this customer group's demands on the RBP vary widely between months, and within months – a very "peaky" load.

On December 1, 2014, the Swanbank E power station was put into "cold storage" and ceased production. Swanbank E accounted for 52 TJ/day of reserved capacity on the RBP in the last access arrangement period. The question of Swanbank's return to service, and its impact on this load and demand forecast, is discussed in section 3.5.3 below.

As discussed more fully in ACIL Allen's report, the reduction in Swanbank demand was partially (and temporarily) offset by increased production at the Oakey power station. The question of whether Oakey's level of operation will remain at this high level is also discussed below.

3.4 Forecast demand and utilisation

3.4.1 *Approach to forecasting*

As discussed above, the RBP Eastbound service serves three distinct classes of customers: retail customers, large industrial customers, and power generation customers. As the characteristics of these customers differ, the demand of each of these classes has been forecast separately.

For the retail and Industrial classes, the forecast load is based on historical flows, adjusted for organic growth in the retail sector, and known changes in the industrial sector.

The forecast for the power generation sector is considerably more complex, with the demand for gas depending largely on the relationship between gas prices, electricity prices, and generation station operating costs. This is analysed in considerable detail in the ACIL Allen report, and summarised below.

The Westbound service is a new service which has only been on offer for a short time. As the characteristics of shippers demanding this service differ sharply from those demanding the Eastbound service, the demand for this service has been forecast separately.

As the Reference Service is direction-ambivalent, the total load forecast will be the combined demand of the Eastbound and Westbound services, acknowledging that some Westbound services may be a redirection of existing Eastbound services.

3.5 Eastbound demand

3.5.1 Retail customers

Following on from the discussion in section 3.3 above, the forecast for the retail load has been based on extrapolation of the historical load and demand, resulting in the forecast shown below. More detail on the methodology applied can be found in ACIL Allen's report, Attachment 3.1.

Table 3.2: Retail customers – forecast load and demand

Retail	2017-18	2018-19	2019-20	2020-21	2021-22
Annual throughput (TJ pa)	15,733	15,762	15,791	15,821	15,850
Peak demand (TJ/day)	59.9	60.0	59.9	60.2	60.3
Load factor	72.0%	72.0%	72.2%	72.0%	72.0%

3.5.2 *Industrial customers*

Similar to the retail load, the first step in forecasting the industrial load has been to extrapolate historical demands, based on known changes to the market.

The forecast for the industrial class rests largely on the demand of two particular customers: the BP refinery at Bulwer Island, and the Incitec Pivot fertiliser plant at Gibson Island, both at the most easterly reaches of the RBP.

The BP Bulwer Island refinery, which was previously responsible for capacity reservation of 35 TJ/day, ceased operations in July 2015. Based on the experience of other Australian refinery closures,[4] the BP Bulwer Island refinery is not expected to resume operations. Going forward, the load and demand associated with this plant has been forecast at zero.

The future operation of the Incitec Pivot fertilizer plant is uncertain. Incitec Pivot operates in a highly price-competitive global industry, and uses natural gas as a primary feedstock to its operations. Incitec Pivot currently has gas supply contracted to the second half of 2018.[5] Its continued operation beyond that point will depend entirely on its ability to secure gas supply at a low enough price that allows it to compete in the global market.

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. 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".[6]

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[4] Closure of the BP Bulwer Island refinery follows closures of ExxonMobil Port Stanvac (Adelaide, 2009); Shell Clyde (Sydney 2012) and Caltex Kurnell (Sydney 2014).

[5] "Gas agreements secure future of fertiliser plants", Incitec Pivot ASX Release dated 6 September 2004 indicates gas supply to mid-2017. Incitec Pivot reports that it has been able source gas to September 2018. See Incitec Pivot Half-year report to 31 March 2016, Appendix 4D, p9.

[6] "IPL releases results for the half year to 31 March 2016", Incitec Pivot Media Release dated 10 May 2016.

The base case forecast assumes that Incitec Pivot will be able to secure future gas supply to continue to operate at current levels. This assumption is challenged in the sensitivity analysis in section 3.5.5 below.

Table 3.3: Industrial customers – forecast load and demand

Industrial	2017-18	2018-19	2019-20	2020-21	2021-22
Annual throughput (TJ pa)	16,450	16,450	16,450	16,450	16,450
Peak demand (TJ/day)	55.9	55.9	55.9	55.9	56.9
Load factor	80.6%	80.6%	80.6%	80.6%	79.2%

3.5.3 *Power generation customers*

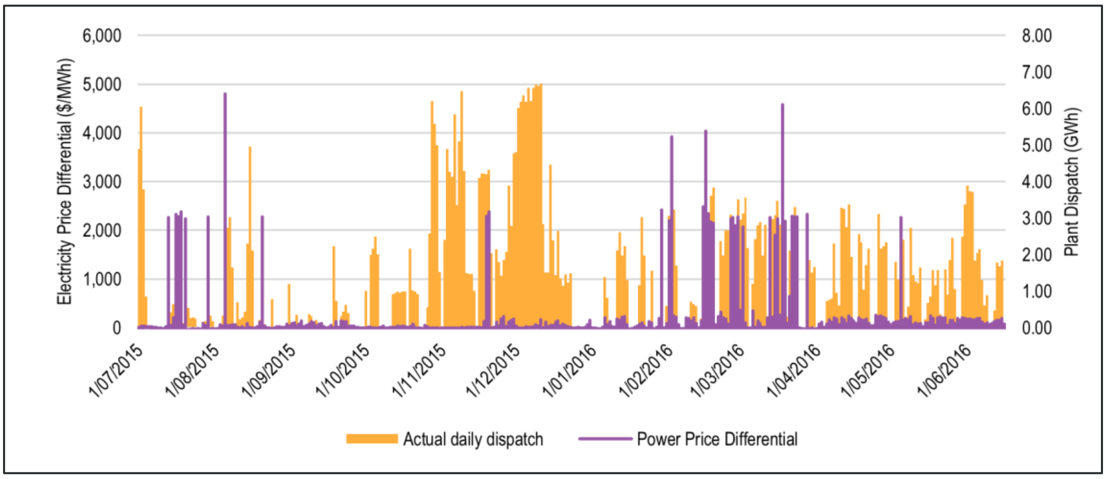
As discussed above, the RBP serves three power generation plants: Oakey, Swanbank E, and Braemar. The load forecast for the power generation class will depend heavily on the expected behaviour of each of these plants, as discussed below.

Oakey

The ERM Oakey open-cycle gas turbine (OCGT) power station runs on gas delivered via RBP with liquid fuel back-up from on-site storage. It operates as a peaking power plant, taking advantage of short periods of high prices in the national electricity market. Its operation is therefore critically dependent on the relationship between electricity and gas prices.

Oakey's operation over the last two years has been profoundly impacted by the flood of ramp gas in the SE Queensland market. ACIL Allen Consulting has identified the periods in which it would be commercially viable for Oakey to operate (when the margin between electricity prices and gas prices, the "spark spread", is high enough to recover short run marginal costs), and overlaid this with Oakey's actual production.

Figure 3.5: Oakey power station operations vs price differentials



Source: ACIL Allen Consulting Figure 4.5.

This chart clearly shows that the Oakey power station was operating vigorously at many times when the observed differential between electricity and gas prices indicates that it would not be commercially viable to do so.

Two questions arise from this observation: 1) what was driving this apparently non-commercial operation of the power station; and 2) do we expect to see this pattern of operation in the forecast period?

ACIL Allen's investigation has revealed that the periods of Oakey's high output coincided with periods of high ramp gas production in the lead-up to the first shipments from GLNG Train 1 (October 2015), APLNG Train 1 (January 2016) and GLNG Train 2 (May 2016).

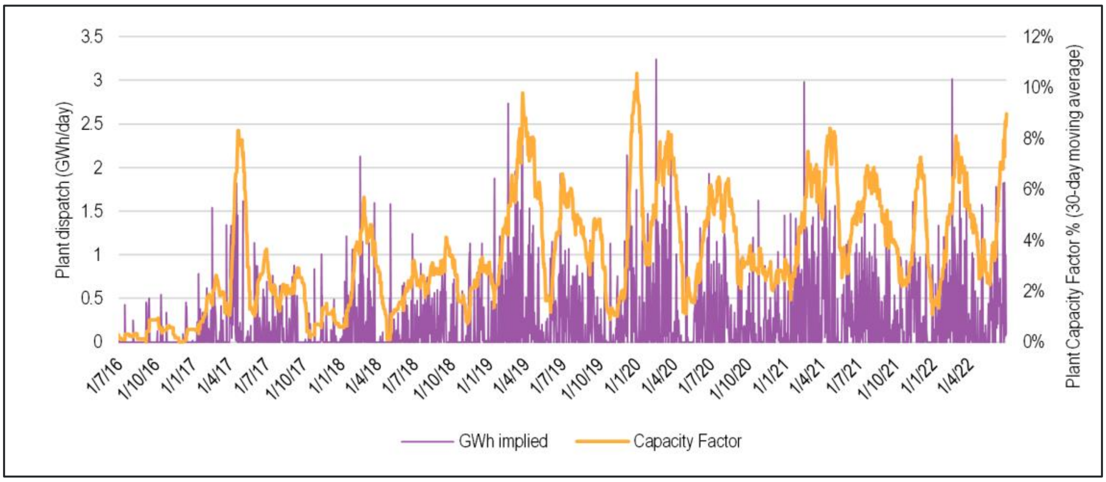
It is unclear from the public record information whether Oakey's high out-of-merit-order dispatch was driven by opportunistic generation to take advantage of low spot gas prices, or whether a gas supplier was tolling its gas through the Oakey power station as a way to monetise its excess supply. However, the answer to this question is not germane to the analysis. It is clear that there was excess gas supply in the market due to the ramp-up of production, and that this gas was used to generate electricity at times when it would not normally have been commercial to do so.

The next question for forecasting purposes is whether we expect this circumstance to persist in the forecast period. As discussed in the ACIL Allen report, once the LNG plants are operating at a "business-as-usual" steady state, we would not expect to see the need to prove production from the coal seam gas wells, and as a result we would not expect to see low cost gas flood the market as we have seen in the ramp-up period.

We therefore do not expect to see Oakey generating "out-of-merit-order" electricity in the forecast period as we have witnessed in the previous period.

We must then examine the commercial nature of Oakey's operation to ascertain the pattern of operation we expect to see going forward. ACIL Allen has modelled the economically efficient levels of operation, with Oakey only producing electricity when it is able to recover its marginal costs. ACIL Allen expects to see Oakey operating at a capacity factor between 2 per cent and 10 per cent, averaging about 4 per cent, as shown below.

Figure 3.6: Oakey forecast generation profile



Source: ACIL Allen Consulting, Figure 4.9.

The forecast pattern of Oakey's operation shows a high peak demand with a very low average demand, resulting in a very low load factor. This will be apparent in the total load and demand data.

With this pattern of consumption, it is unlikely that Oakey power station will seek to book firm capacity on the RBP. This is discussed further in section 3.5.7 below.

Swanbank E

The Swanbank E Power Station, located 10 kilometres south of Ipswich in SE Queensland, is a 385 MW combined cycle gas turbine (CCGT) power station which features the Alstom GT26 gas turbine — the largest gas turbine in Australia at the time of its commissioning in 2002.

On December 1, 2014, the Swanbank E power station was put into "cold storage" and ceased production. Owner Stanwell Corporation indicated that:[7]

> *Swanbank E was put in cold storage on 1 December 2014 for up to three years. It will not be used to generate electricity at this time.*
>
> *Analysis of the electricity and gas trading markets concluded that greater value could be achieved from Stanwell's gas entitlements by selling the gas rather than using it to generate electricity.*

Swanbank E accounted for 52 TJ/day of reserved capacity on the RBP in the last access arrangement period.

This section analyses the question surrounding Swanbank E's return to service and the implications for the RBP load and demand forecast.

As discussed above, the Oakey power plant is a "peaking" power plant that can produce electricity on short notice to take advantage of short term spikes in electricity prices. In contrast, ACIL Allen advises that the technical design of Swanbank E is not well-suited to running at low capacity factors; 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.

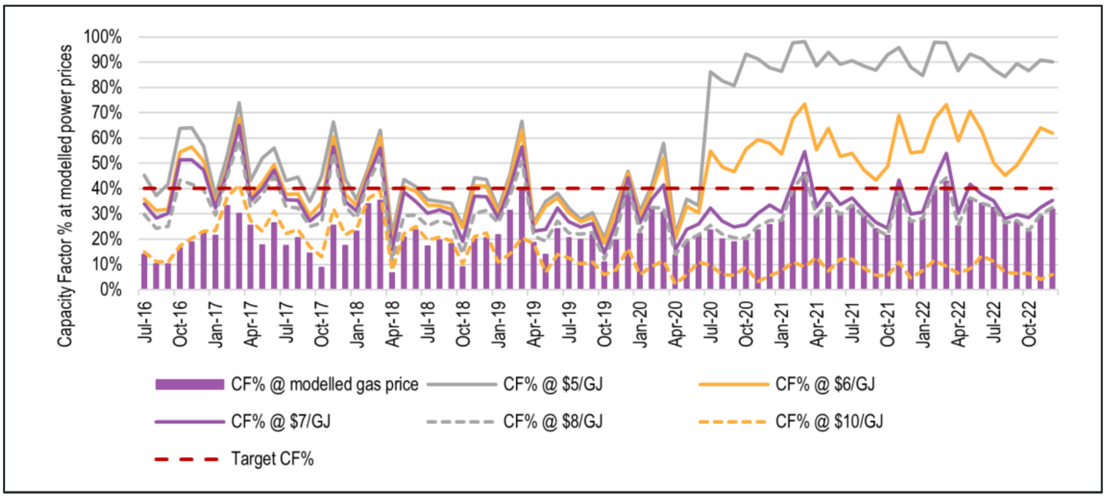
An analysis of whether Swanbank E will return to service in the forecast access arrangement period will depend on whether the relationship between gas and electricity prices would sustain high enough levels of dispatch for Swanbank E to return to service.

ACIL Allen has conducted this analysis, as reported in Attachment 3.1. In summary, ACIL Allen found that, even at very low gas prices, it was unlikely

[7] Stanwell Corporation, Swanbank E Power Station Fact Sheet, December 2014.

that Swanbank E would be able to attain a sufficient level of dispatch to return to service before 2020.

Figure 3.7: Swanbank E capacity factors at different gas prices



Source: ACIL Allen Consulting, Figure 4.12.

Impact of an assumed price on carbon

However, it is critical to note that this "return to service" date is driven by an assumption that an explicit price on carbon of $25/tCO2e will be introduced in January 2020, escalating to $50/tCO2e by 2030. This assumption is found in a consultant report by Jacobs,[8] provided to AEMO in the context of its 2016 National Electricity Forecasting Report (NEFR). Jacobs assumes:

> *Prices bounce back in 2020, despite the further commissioning of renewable energy capacity, because of the introduction of a $25/t CO2-e carbon price in that year. [p11] …*
>
> *In 2020 with the introduction of the carbon price Queensland [wholesale electricity price] rises by 31% and is projected to briefly have the highest annual price in the NEM, even exceeding the South Australian price. [p13] …*

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

It is this "bounce-back" in prices, driven by the assumed introduction of a carbon price, that drives the conclusion that Swanbank E could be dispatched frequently enough to return to service in 2020.[9]

The Jacobs report does not appear to include any justification or reasoning behind this assumption, commenting only that:

> *The Commonwealth Government introduced a carbon pricing mechanism on 1 July 2012. This was repealed in July 2014 following a change in government. For the purpose of modelling, it is assumed that a carbon scheme returns from 2020 at $25/t CO2-e and escalates linearly, reaching $50/t CO2-e by 2030. [p28]*

While AEMO's 2016 NEFR Methodology Paper makes no explicit mention of a carbon price assumption, it appears to have implicitly (and potentially inadvertently) incorporated Jacobs' assumption on this matter. ACIL Allen has included this same assumption in its modelling to enhance comparability with AEMO's results.

APTPPL notes that the question of introducing a price on carbon is a matter for government to decide. The government's current policy position is 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".[10]

APTPPL considers that it is not reasonable to assume a change in government policy in the face of an existing contradictory policy position.

ACIL Allen's analysis concludes: (p40)

> *… In the absence of a carbon price, capacity factors would be expected to continue at around the pre-2020 modelled levels.*
>
> *Based on this analysis, we can conclude that two critical factors will determine whether or not it is technically and economically*

[9] Albeit only with a delivered gas price less than $6/GJ.

[10] "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. http://foreignminister.gov.au/releases/Pages/2015/jb_mr_150811.aspx?w=tb1CaGpkPX%2FlS0K%2Bg9ZKEg%3D%3D

> *viable for Swanbank E to return to service during the next access arrangement period:*
>
> 1. *Whether an explicit carbon price is reintroduced, and if so the timing and level of that carbon price. …*
> 2. *Whether Stanwell is able to obtain replacement gas supply of at least 30 TJ/day, under firm supply contracts and on a delivered basis, at a cost of less than about $6/GJ. …*

ACIL Allen's analysis then goes on to find that 1) there is no policy basis for an assumption that an explicit price on carbon will be re-introduced, and 2) that the prevailing cost of gas is likely to be higher than $6/GJ ($7.50-$7.90/GJ in the CORE Energy "low" case[11]).

> *We therefore find that … the wholesale electricity market prices that would be received by Swanbank E over the period 2017 to 2022 are unlikely to be sufficient to enable it to achieve a technically and commercially sustainable capacity factor while covering its expected short-run marginal costs of generation….*
>
> *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.*

Summary – Swanbank E

In summary, the base case forecast assumes that Swanbank E will not return to service before 2022, and has therefore forecast zero load in the forecast access arrangement period. Notwithstanding the clarity of the findings in this regard, this assumption is challenged in the sensitivity analysis in section 3.5.5 below.

Braemar

As discussed above, the Braemar power station at Condamine has alternate gas supply arrangements in place, and takes only a small portion of its gas

[11] CORE Energy Group (2015): AEMO Gas Price Consultancy, August 2015.

supply from the RBP. Historically, this has been in the order of 8 per cent of annual requirements.

The base case forecast assumes that Braemar continues to take gas from the RBP equivalent to 8 per cent of its annual requirements.

Summary – power generation customers

In summary, the base case load forecast for the power generation sector is shown below. The low load factor, particularly in comparison to the Industrial load, is a function of the rare utilisation of peak capacity demanded by the Oakey power station, as shown in Figure 3.6.

Table 3.4: Power generation customers – forecast load and demand

Power Gen	2017-18	2018-19	2019-20	2020-21	2021-22
Annual throughput (TJ pa)	787	1,586	1,862	1,789	1,973
Peak demand (TJ/day)	45.1	63.1	68.1	64.0	68.2
Load factor	4.8%	6.9%	7.5%	7.7%	7.9%

3.5.4 *Summary – eastbound demand*

Combining the findings above related to the retail, Industrial and Power Generation customer classes, the base case forecast for Eastbound load and demand over the 2017-22 access arrangement period is shown below.

Table 3.5: Eastbound – forecast load and demand

Eastbound	2017-18	2018-19	2019-20	2020-21	2021-22
Aggregate Annual throughput (TJ pa)	32,969	33,798	34,104	34,060	34,273
Aggregate Peak demand (TJ/day)	139.3	154.9	159.3	156.0	160.5
Load factor	64.8%	59.8%	58.7%	59.8%	58.5%

The aggregate peak demand is a coincident (system) demand, reflecting that different customer classes demand peak capacity at different times. For example, the residential load tends to be a winter peaking load, whereas the power generation load tends to be a summer peaking load.

It should also be noted that this forecast peak demand is driven by the behaviour of the Oakey peaking power station. As shown in Figure 3.6, this level of demand is only likely to be observed on approximately 10 days per year. With this load profile, Oakey is unlikely to reserve firm capacity.

In terms of forecast capacity reservation for tariff setting purposes, APTPPL proposes a forecast of firm capacity reservation in the order of 150 TJ/day. This is consistent with the load and demand forecast presented above, and also consistent (allowing for some organic Retail load growth) with the previous level of reserved capacity (232 TJ/day) less the reserved capacity for the closed BP Bulwer Island refinery (35 TJ/day) and the mothballed Swanbank E generation station (52 TJ/day). This is addressed in section 3.5.9

3.5.5 *Sensitivity analysis*

Generally, a load and demand forecast should reasonably test the sensitivity of the overall forecast to a range of assumptions. Normally, one might test the sensitivity to the rate of organic growth in the retail market, or the sensitivity of the load forecast to assumptions on the general level of inflation or GDP growth.

However, following the discussion above, there are two key factors that would overwhelm any analysis of growth rates, and should be considered in performing a sensitivity analysis on the base case load forecast:

- The question of whether Incitec Pivot is able to secure gas supply to enable it to continue operating over the access arrangement period (impact of 42 TJ/day); and
- The question of whether Swanbank E is able to secure sufficient low-cost gas supply to return to service within the access arrangement period (impact of 59 TJ/day).

Owing to the nature of these operations, the answers to these questions are binary - either Incitec Pivot will continue to operate at current levels, or it will close the Gibson Island fertilizer plant; either Swanbank E will secure gas supply, and the National Energy Market will regularly settle at a sufficiently high price in order for it to maintain a profitable level of dispatch, to enable it to resume operations at a commercial level, or it will remain mothballed.

As outlined above, the base case assumes that Incitec Pivot will continue operations at current levels, and that Swanbank E will not resume operations within the forecast period. By changing these assumptions, we derive the low case and high case as follows:

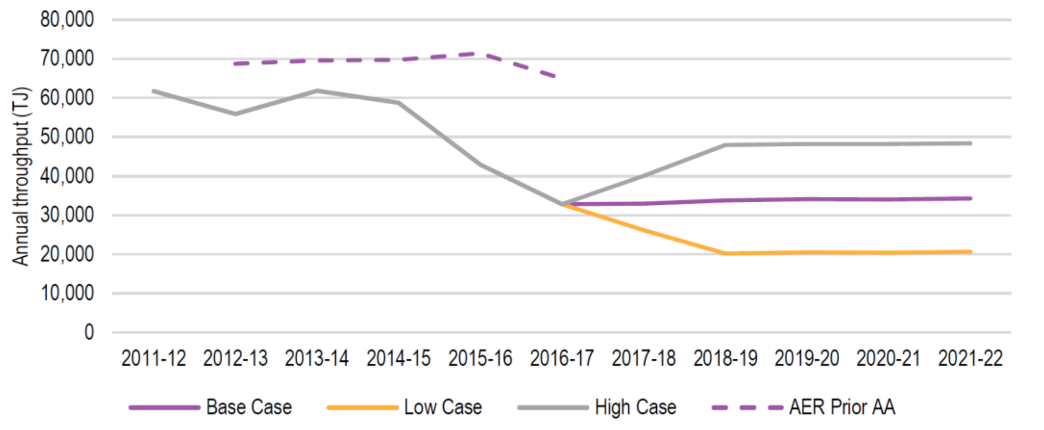
Table 3.6: Eastbound – low, base and high cases

Eastbound	Low Case	Base Case	High Case
Incitec Pivot	0 TJ/day	42 TJ/day	42 TJ/day
Swanbank E	0 TJ/day	0 TJ/day	59 TJ/day

While these impacts dominate the analysis, the high case forecast also assumes additional gas being taken by the Braemar power stations; the low case forecast assumes a lower proportion of gas taken by the Braemar power station.

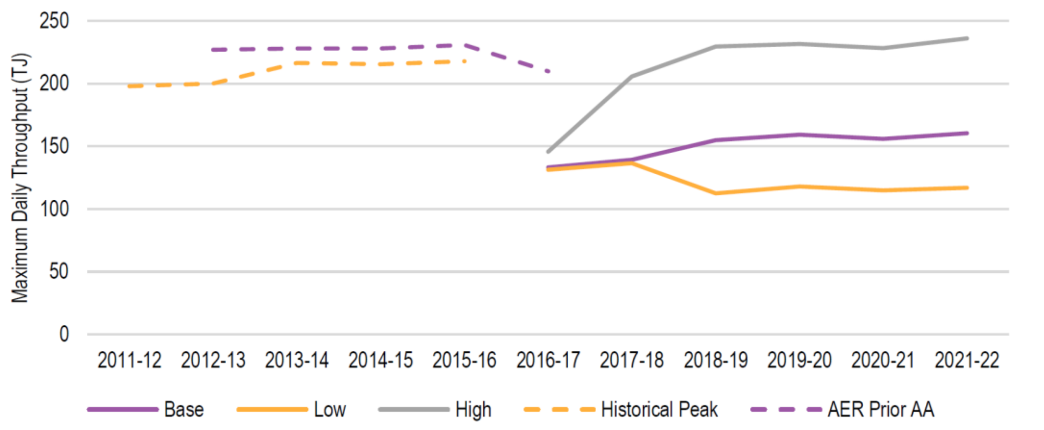
The low, base and high cases for total throughput and peak demand are presented graphically below.

Figure 3.8: RBP forecast annual throughput – base, low and high cases



Source: ACIL Allen Consulting, Figure ES1.

Figure 3.9: RBP forecast peak demand – base, low and high cases



Source: ACIL Allen Consulting, Figure ES2.

It should be noted that the peak demand is driven largely by the expected behaviour of the Oakey power station, as described in section 3.5.3. As shown in Figure 3.6, these peak demands are only anticipated to occur on one or two days per year.

APTPPL's ability to influence these outcomes

The Incitec Pivot and Swanbank E loads are significant in terms of total RBP demand. It is reasonable to ask, in that context, whether there is anything APTPPL can do to influence the decision-making of these shippers, either to avoid the low case occurring, or encouraging the high case to eventuate.

In both cases, the viability of the business' operations depend critically on the price of gas; as a fuel in the case of Swanbank E, or as a feedstock in the case of Incitec Pivot. The ability of APTPPL to influence these customers' decision-making will be influenced by the relativity between the commodity gas price, and the tariff for pipeline transport.

By way of comparison, the current (2016-17) posted firm tariff for RBP transport is in the order of $0.68 per GJ. CORE Energy's 2015 advice to AEMO[12] for power generation in the eastern states 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.

While APTPPL cannot influence the global price for urea or the wholesale electricity price, it can exert some influence on the delivered gas price. However, with transmission tariffs in the order of 7-10 per cent of the delivered gas price, the degree of influence is clearly limited.

The National Gas Rules (Rule 96) include a "prudent discount" feature, under which tariffs can be reduced to vulnerable shippers (those at risk of closure, or with alternate supply or bypass options), with the revenue shortfall to be recovered by other shippers. Under this provision, the goal is that, even though a user's incremental load is retained at a discounted price, overall tariffs may be lower because of the user's contribution to fixed costs.

It is not at all clear, however, that APTPPL would be able to influence the business decisions of either Incitec Pivot or Swanbank E.

In the case of Incitec Pivot, the Gibson Island fertiliser plant consumes 14 PJ of gas at nameplate capacity[13] and has been operating at 85% of that

[12] CORE Energy Group (2015): AEMO Gas Price Consultancy, August 2015.

[13] Incitec Pivot 2014 Annual Report Appendix 4E, p73.

capacity.[14] This suggest annual gas consumption in the order of 11.9 PJ/year.

Incitec Pivot's 31 March 2016 Half-year Report (p11) indicates that the half-year EBIT for the Incitec Pivot fertiliser business was $14.5 million.[15] This suggests that an increase of only $2.44 would render the plant unprofitable over the full year. Incitec Pivot's impairment testing has assumed a gas price (excluding transport) of $9.00 per GJ.[16]

The Incitec Pivot fertiliser business reports sales to external customers of $338m for the 6 months to 31 March 2016, and EBITDA of $29.8m,[17] suggesting total operating costs of $308m for the 6 months. At the Reference Tariff, total RBP transportation costs would be in the order of $5.2m for the half year, or about 1.7% of total operating costs.

Regarding Swanbank E, the low relative proportion of transmission costs relative to commodity gas costs similarly suggests that, even with a discounted tariff, APTPPL will not be able to influence Swanbank's decision of whether or not to resume operations. This is particularly the case given that the assumed start date relies heavily on an assumption of re-introduction of a price on carbon.

3.5.6 *Forecast demand and shipper behaviour*

The analysis above estimated the total forecast load and peak demand for gas transportation services on the RBP over the 2017-22 access arrangement period. However, it did not address the question of how users would be likely to contract for gas transportation services.

This question has significant implications in the context of:

- both Long Term Firm and Short Term Firm Services being offered as Reference Services;

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[14] Incitec Pivot September 2015 preliminary financial report Appendix 4E, p11.

[15] Incitec Pivot 31 March 2016 Half-year Report Appendix 4D, p11.

[16] Incitec Pivot 31 March 2016 Half-year Report Appendix 4D, p10.

[17] Incitec Pivot 31 March 2016 Half-year Report Appendix 4D, p11.

- the spare capacity on the pipeline (and the practical risk of Short Term Firm Services not being available); and
- the need for APTPPL to have a reasonable opportunity to recover its allowed revenues in the context of s24(2) of the *National Gas Law*.

This section investigates the question of what proportion of the load is likely to booked as Long Term Firm capacity, how much is likely to be booked as Short Term Firm transport, and how the relationship between the Long Term Firm and Short Term Firm tariff could impact this decision. Our goal is to estimate the amount of Long Term Firm and Short Term Firm transport to be purchased at the Long Term Firm and Short Term Firm tariffs to be determined, within the constraint of recovering the total allowed revenue in accordance with NGL s24(2).

The behaviour of shippers will be driven by the nature of their gas transportation needs, and the price relativity between Long Term Firm and Short Term Firm Services. We start this analysis by determining the appropriate relationship between the Long Term Firm and Short Term Firm tariffs.

We then examine the expected contracting behaviour of shippers, recognising the commercial relationship between fixed Long Term Firm charges and Short Term Firm charges.

We then use this information to estimate the amount of Long Term Firm capacity shippers will book, and a revenue-neutral amount of Long Term Firm capacity to represent the Short Term Firm services. The total of these amounts is then used to determine the Long Term Firm Reference Tariff. The Short Term Firm Reference Tariff is determined by applying the Short Term Firm multiple to the Long Term Firm Reference Tariff.

3.5.7 Expected shipper behaviour in forecast access arrangement period

It is important to distinguish the nature of Long Term Firm vs. Short Term Firm services. Long Term Firm capacity is sold subject to a take-or-pay arrangement; the shipper must pay for reserved capacity over a longer term, even if it is unutilised on a particular day. In the case of Short Term Firm services, the shipper pays only for that capacity over the short term contracted (as little as one day).

The Short Term Firm tariff is a short term capacity reservation charge rather than a long term capacity reservation charge. This has significant implications for the certainty of the pipeline owner's revenue stream.

Under a Long Term Firm capacity tariff, the shipper pays the cost of its unutilised capacity. A shipper with a low (peaky) load factor will therefore pay a higher proportion of its total cost for unutilised capacity than a shipper with a high (flat) load factor. The lower the shipper's load factor, the greater will be its preference for Short Term Firm service offerings (as short as one day) in which it is not required to pay for extended periods of unutilised capacity.

Further to the discussion above, APTPPL anticipates that those shippers with a high load factor, or with firm obligations (in particular, the large industrial and retail customers with load factors in the order of 80%) will tend to book their full requirements as Long Term Firm capacity. At the other end of the scale, peaking power plants and commodity traders, with a very low load factor, are unlikely to reserve any Long Term Firm capacity at all, and rely entirely on the availability of the Short Term Firm service.

We will therefore be required to translate the amount of Short Term Firm utilisation to a revenue-equivalent level of Long Term Firm demand, in order to calculate the Long Term Firm tariff. The Short Term Firm multiplier would then be applied to determine the Short Term Firm tariff.

This is discussed in section 3.5.8 below.

3.5.8 Relationship between Long Term Firm and Short Term Firm tariffs

The Long Term Firm Service is a capacity reservation service, under which the Service Provider undertakes to hold capacity available for the shipper's use for the duration of the contract. The Shipper is entitled to trade that capacity should it choose to do so.

As a capacity service, the tariff for the Long Term Firm Service is based on the amount of capacity reserved each day (rather than the amount used on a particular day) and therefore does not vary based on the amount of gas transported.

In contrast, the Short Term Firm Service applies to short contracting periods, potentially relating to nominations made the day prior to the transportation service being provided – no "excess" capacity is likely to be reserved under this service. Accordingly, the Short Term Firm service is charged on the basis of the amount of capacity reserved over the shorter contracting period.

Shippers choosing the Long Term Firm Service generally reserve capacity to meet their peak day demand to be sure they will have sufficient capacity available to meet their needs or meet their obligations. These shippers recognise that, as capacity is charged based on the amount reserved, there will be occasions when capacity is reserved (and paid for) but is not utilised on a particular day.

The value of the Short Term Firm Service is that it is not charged if it is not contracted. As shippers choosing the Short Term Firm Service are expected to use this service to "sculpt" their loads, they will not incur charges for capacity that is reserved but unutilised. Under this structure, it is anticipated that the Short term Firm Service will be utilised to a very high load factor, approximating 100 per cent. The Short Term Firm capacity tariff is therefore equal to a "per GJ" transportation charge.

To demonstrate the relative value of these Services, we translate the capacity charge under a Long Term Firm contract to a comparable charge that would be incurred under a Short Term Firm arrangement.

The key to this translation is the shipper's load factor. The load factor is calculated as the ratio of the shipper's average daily demand (that is, total annual throughout divided by 365) to its peak demand.

A high load factor (that is, peak demand approximately equal to average demand) is a sign of a very stable, "flat" load. This is often observed in large industrial operations. In contrast, a low load factor (peak demand is high relative to average demand) is a sign of a variable, "peaky" load. This is often observed in temperature-sensitive loads, particularly in colder climates. A low load factor is also observed in cases where gas is used opportunistically in response to variable market signals. For example, we see very low load factors in peaking power plants that respond to differentials between gas and electricity prices, and also to commodity traders that take advantage of transient market opportunities.

To convert a long term capacity tariff to an equivalent "per GJ" charge, the capacity tariff is divided by the shipper's load factor. A shipper under a Long Term Firm contract, transporting gas with a 66% load factor (its average day demand is 66% of its peak day demand), will incur an equivalent "per GJ transported" charge of 150% times the capacity tariff. This occurs because the Long Term Firm shipper pays for a certain amount of reserved capacity, which, as demonstrated by its load factor, it does not use. This is the cost the shipper incurs to have certainty that its reserved capacity will be provided on any day required (particularly its maximum day).

As discussed above, APTPPL anticipates that peaking power plants (and shippers taking the Westbound service, discussed below) will not choose to reserve firm capacity, but will choose to use the Short Term Firm service.

This presents a challenge for tariff setting where the objective is to obtain a target level of revenue. APTPPL therefore proposes to apply a tariff multiplier, determined using the forecast levels of average and peak demand to derive Short Term Firm tariffs from the posted Long Term Firm tariffs.

Box 1: Relationship between Long Term Firm and Short Term Firm

Gas transmission pipelines are constructed to provide users with firm transportation service. They are long-lived assets, and service providers will typically seek to enter into long term contracts with firm service users to ensure sufficient certainty in future revenues to secure the long term financing of the assets.

The RBP's Long Term Firm service is a capacity service, and its price can be quoted solely in terms of a number of GJ per unit of contracted capacity. There is no throughput charge, and the price a user pays, per GJ of gas delivered is p^{LTF}/L, where p^{LTF} is the Long Term Firm capacity charge.

The Short Term Firm service is the service of delivering a user's gas on the nominated day (the day ahead). At the anticipated 100% load factor, its capacity charge is equivalent to a "per GJ transported" throughput charge.

Suppose the price per GJ of gas delivered using Short Term Firm is p^{STF}.

The RBP has sufficient spare capacity to allow users to be reasonably sure of obtaining Short Term Firm Services whenever they require pipeline capacity. In these circumstances, APTPPL is willing to provide Short Term Firm Services only when the a unit of gas delivered using Short Term Firm earns at least as much revenue as a unit of gas delivered using Long Term Firm. If the price of Short Term Firm were less than the price of Long Term Firm (per GJ of gas delivered), users would not contract for Long Term Firm, and would put at risk the long term financing of the pipeline.

Assuming all users have same load factor, L, the minimum price per GJ of gas delivered at which APTPPL will provide Short Term Firm is:

$p^{STF} = p^{LTF}/L$.

The access regulatory regime of the NGL and the NGR applies to the RBP, and the prices p^{STF} and p^{LTF} should be set to recover the present value of APTPPL's total revenue (costs) over an access arrangement period.

Suppose the access arrangement period is one year. This simplification avoids the notational complexity of the present value calculations, while retaining the key point of the argument. If q^{LTF} is the capacity contracted for Long Term Firm Service, and q^{STF} is the capacity used to provide Short Term Firm, then:

$p^{LTF} \times q^{LTF} + p^{STF} \times q^{STF} = TR$.

If the minimum price at which APTPPL will provide Short Term Firm is $p^{STF} = p^{LTF}/L$, then

$p^{LTF} \times q^{LTF} + p^{LTF} \times q^{STF}/L = TR$,

so that:

$p^{LTF} = TR/[q^{LTF} + q^{STF}/L]$.

That is, the Long Term Firm capacity charge, p^{LTF}, is determined by dividing the total revenue by the sum of:

- the capacity contracted for Long Term Firm; and
- the long term capacity-equivalent of the capacity used to provide Short Term Firm, which is a multiple, 1/L, of the quantity of that capacity, where L is the load factor.

The Short Term Firm charge is $p^{STF} = p^{LTF}/L$.

In effect, 1 GJ of capacity used to provide Short Term Firm is equivalent to 1/L GJ of contracted Long Term Firm Capacity.

APTPPL proposes to set the relationship between the Long Term Firm capacity tariff and the Short Term Firm capacity tariff in accordance with the composite pipeline load factor.

The forecast five-year average load factor calculations are presented below:

Table 3.7: Forecast five year average system load factor calculations[18]

Forecast	2017-18	2018-19	2019-20	2020-21	2021-22
Maximum demand	139.3	154.9	159.3	156.0	160.5
Average demand	90.3	92.6	93.2	93.3	93.9
Composite load factor	64.8%	59.8%	58.8%	59.8%	58.5%
Average load factor					60.3%
Forecast Short Term Firm multiplier					**166%**

APTPPL considers that the forecast composite load factor is the relevant measure to use, as it reflects the current load forecast circumstances in the context of the demand for gas and pipeline services in the SE Queensland market. APTPPL proposes to apply a factor of 166% as the relationship between the Long Term Firm Service tariff and the Short Term Firm Service tariffs for the 2017-22 access arrangement period.

Implications

It should be noted that fixing the relationship between the Long Term Firm tariff and the Short Term Firm tariff has broader consequences. As developed more fully below, a lower relative Short Term Firm tariff will encourage shippers (particularly shippers with low load factors) to abandon the Long Term Firm service in favour of the Short Term Firm service.

Within the constraint of achieving a given amount of allowed revenue in accordance with NGL s24(2), a lower multiplier will result in a higher Long Term Firm tariff. This will result in a transfer of wealth from shippers with high load factors (such as industrial and retail customers) to shippers with low load factors (such as peaking power plants and commodity traders).

[18] Data source: Acil Allen Consulting, Roma to Brisbane Pipeline, Assessment of Demand for Services, Figures 4.13 and 4.14.

3.5.9 *Long Term Firm forecast*

Current contract positions

APTPPL notes that the Reference Service under the current Access Arrangement provides for a contract term of three years. It would be reasonable to expect, therefore, that there are some contracts that will still be on foot at the commencement of the forecast Access Arrangement period.

As discussed in section 3.5.7 above, APTPPL expects shippers to reduce their reliance on the Long Term Firm service once current contracts expire, and increasingly rely on the ready availability of the Short Term Firm service to manage their peak demand needs. That is, we do not expect shippers to reserve "headroom" capacity in future Long Term Firm contracts.

Recognising this anticipated change in contracting behaviour, APTPPL has measured the Eastbound load forecast as the greater of 1) currently contracted capacity; and 2) peak demand, for the purposes of determining tariffs for the upcoming access arrangement period.

Table 3.8: Forecast Long Term Firm demand

	2017-18	2018-19	2019-20	2020-21	2021-22
Current capacity contracts	156.5	134.5	110.3	97.5	87.0
Forecast peak demand:[19]					
Industrial	55.9	55.9	55.9	55.9	55.9
Retail	59.9	60.0	59.9	60.2	60.3
Total forecast peak demand	115.8	115.9	115.8	116.1	116.2
Long Term Firm Forecast (TJMDQ/day)	**156.5**	**134.5**	**115.8**	**116.1**	**116.2**

[19] Acil Allen Figure 4.14.

3.5.10 *Short Term Firm forecast*

In addition to the forecast for the Long Term Firm service, it will be necessary to derive a forecast for the Short Term Firm service.

As discussed above, a key customer class that is likely to take the Short Term Firm service is gas-fired power generators. ACIL Allen has forecast the level of gas flow expected to be require for these customers in the report lodged in Attachment 3-1.

In order to set tariffs at the correct level, it is necessary to translate the anticipated level of Short Term Firm demand to a revenue-neutral level of Long Term Firm demand.

Keeping in mind that the Long Term Firm service is a capacity reservation service, we accomplish this translation by multiplying the forecast amount of Short Term Firm throughput by the Short Term Firm multiplier (1.66).[20] We would then divide this by 365 days per year to derive a revenue-neutral level of Long Term Firm capacity reservation.

Applying this approach, forecast transportation of 787 TJ over the course of a year under Short Term Firm arrangements would be expected to deliver the same amount of revenue as if the shipper had booked 3.58 TJMDQ/day of Long Term Firm capacity.[21]

The Long Term Firm equivalent load forecast for the power generation load is set out below:

Table 3.9: Forecast power generation Long Term Firm equivalent demand

Eastbound	2017-18	2018-19	2019-20	2020-21	2021-22
Power Gen throughput[22]	787	1,586	1,862	1,789	1,973
Long term Firm equivalent	**3.58**	**7.19**	**8.42**	**8.07**	**8.88**

[20] That is, 100GJ transported every day under Short Term Firm arrangements will deliver 1.66 times the revenue of 100GJ/day of capacity reservation under a Long Term Firm arrangement.

[21] (787 x 1.66) ÷ 365 = 3.58 TJMDQ/day equivalent.

[22] Acil Allen Figure 4.13.

3.6 Westbound demand

APTPPL completed a variation of its pipeline license and capital works to allow firm westbound transmission on the RBP, and delivered its first westbound gas into the Wallumbilla Hub, in October 2015.

The discussion in the ACIL Allen report included as Attachment 3.1, and summarised below, derives a westbound demand forecast from a detailed analysis of all potential shippers in the region, the nature of their needs for gas transportation services, and their alternatives.

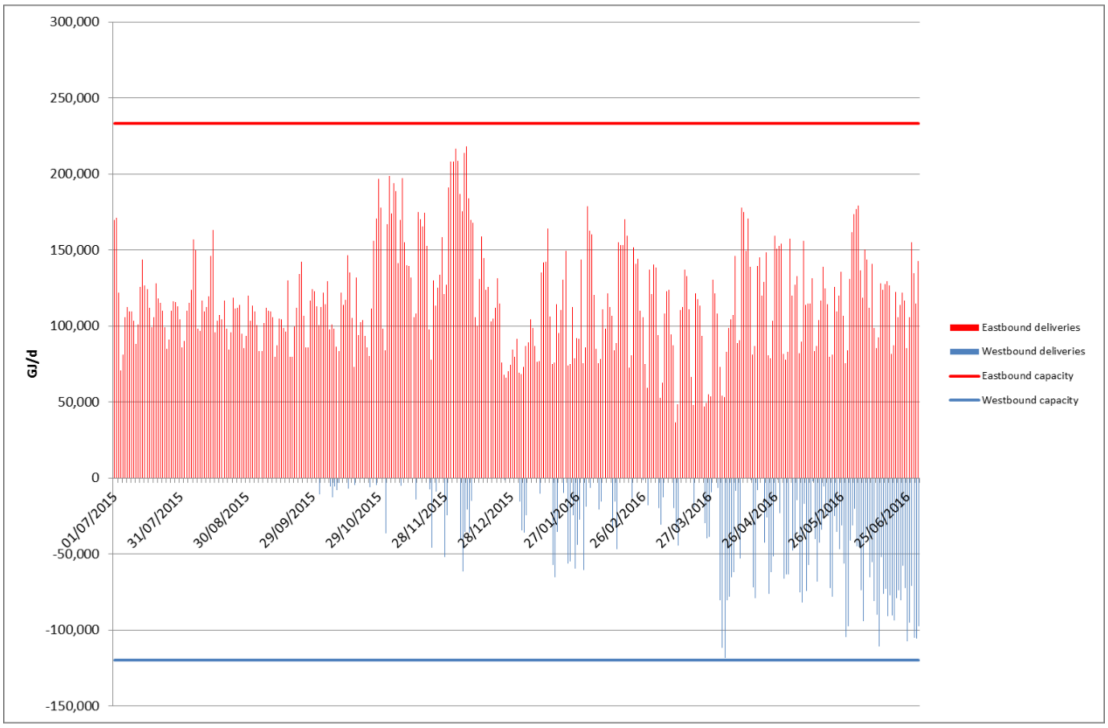
As with the Eastbound forecast, the Westbound forecast is developed based first on a review of historical flows, and then on an analysis of the particular types of users of the Westbound service:

- CSG LNG Producers;
- Energy retailers;
- Other producers;
- Major domestic gas users looking to on-sell gas entitlements; and
- Spot market traders.

3.6.1 Historical Westbound demand

Figure 3.10 shows the quantities of Eastbound (positive) and Westbound (negative) deliveries on the RBP for the 2015-16 year. The westbound capacity of the RBP is 120 TJ/day.

Figure 3.10: RBP Eastbound and Westbound deliveries



Source: APA meter data.

While this chart shows that there has been some uptake of the westbound service, it clearly shows that the demand has been sporadic, possibly reflecting the early nature of this service provision. To date, there has been no material longer term contracting for firm westbound service.

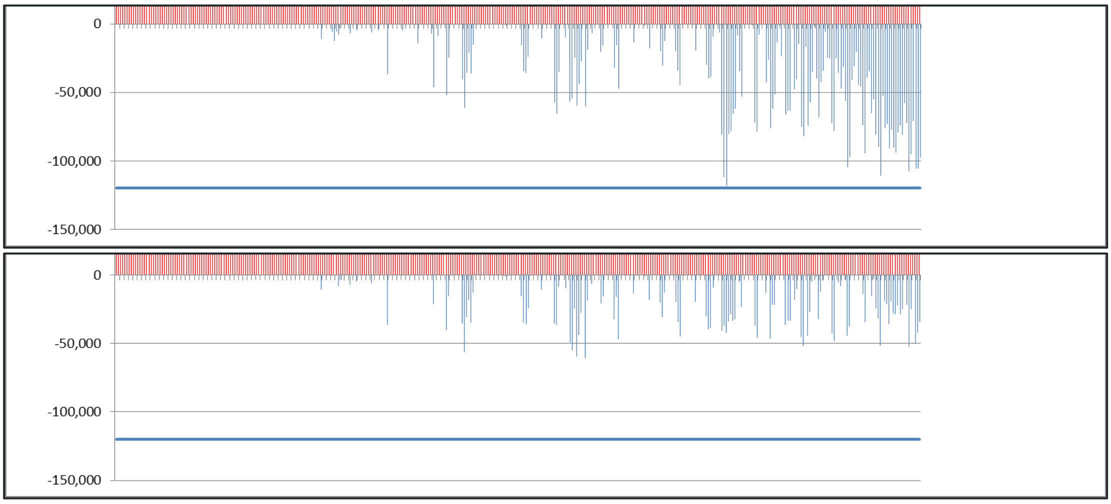
In reviewing the level of historical westbound flows in 2015/16, it is important to understand the drivers of these historical flows to ascertain whether the observed trend is likely to persist. Importantly, the levels of Westbound flow observed during the first half of 2016 have been significantly affected by transient requirements, notably:

- a short-term arrangement to allow supply to domestic markets to meet a seasonal increase in demand. It is not obvious that the gas supplier in question is likely to seek similar seasonal services in future; and
- 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. This requirement is unlikely to be repeated.

As it is not at all clear that these drivers will continue into the future, the 2016 observed levels of westbound transportation demand should not be viewed as any indication of the forecast level of westbound demand.

APTPPL has therefore normalised the observed Westbound delivery data by removing the impact of these two loads. The observed and normalised quantities of RBP Westbound deliveries for the 2015-16 year are shown below.

Figure 3.11: RBP observed and normalised Westbound flows



Source: APA meter data.

Particularly considering the short term over which the Westbound service has been on offer, APTPPL considers that the observed historical usage of the Westbound service for the 2015/16 period is not a good indicator of the sustainable level of demand for this service.

3.6.2 *Demand analysis*

In this section we summarise the ACIL Allen analysis of the types of shippers that might utilise the Westbound service, their demand drivers, and to what extent they might demand Westbound RBP services.

For each type of shipper (and each major shipper in each type) the analysis considers how the shipper might use the RBP Westbound service:

- to deliver gas to an LNG plant;

- to divert "balancing" gas volumes, temporarily or permanently, from CSG 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; or
- to deliver gas to Wallumbilla for trading at Wallumbilla Hub.

The ACIL Allen analysis also considers, for each potential shipper:

- 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; and
- how much the user might be willing to pay to access RBP Westbound Service and the drivers of those price tolerances:
    - 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; or
    - on an as-available basis, paying only on the days when they need it.

In assessing the potential for shippers to demand the RBP Westbound service, the ACIL Allen analysis examines the location of producing acreage and the location of other (particularly dedicated) pipeline infrastructure relative to the RBP.

More detail can be found in the ACIL Allen report included at Attachment 3.1.

3.6.2.1 LNG producers

It is important to note that the LNG producers (QCLNG, APLNG and to a lesser extent GLNG) operate with dedicated gas supply regions, and have built dedicated gathering and transmission facilities to ship that gas to their respective plants.

For normal day-to-day operations, all these LNG projects have access to dedicated infrastructure that negates any need to access RBP Westbound service. The only time an LNG producer would seek to use the RBP Westbound service is when it is unable, for operational reasons, to utilise its own dedicated infrastructure.

In summary, ACIL Allen finds it difficult to conceive of a situation in which APLNG or GLNG would ever make use of RBP Westbound services. There may be some scope for QCLNG to use the RBP Westbound service, but it is likely to be very intermittent, with high demand for short periods separated by long periods of zero demand.

3.6.2.2 *Energy retailers*

ACIL Allen examined the retailers' gas supply portfolios as announced by the retailers. It found that:

- AGL might use 10 TJ/day firm RBP Westbound service plus 90 TJ/d non-firm, used at very low frequency, for which it assumes 1% (3.65 days/year);
- It is difficult to conceive of a situation in which Origin Energy would make use of RBP Westbound services;
- EnergyAustralia does not sell retail gas in the Queensland market and does not, to ACIL Allen's knowledge, hold any upstream gas entitlements in the Surat/Bowen Basin region serviced by RBP; and
- 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 Eastbound RBP volumes

ACIL Allen therefore concludes that the retailers may book 10 TJ/day Long Term Firm Westbound capacity, and use the Westbound service as much as 3.65 days per year for 60 TJ/day on those days. Following the calculation methodology above, this would translate to a Long Term Firm equivalent of 10.996 TJMDQ/day.

3.6.2.3 *Other producers*

ACIL Allen finds that 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 Westbound services could be advantageous.

Arrow Energy produces gas from the 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.

While acknowledging a significant risk that this booking may not materialise, ACIL Allen assumes 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.

3.6.2.4 *Major domestic gas users looking to on-sell gas entitlements*

There remain only two domestic gas users that could potentially on-sell the gas entitlements: Swanbank E and Incitec Pivot.

The Swanbank entitlements are sourced either from QGC Berwyndale (not requiring access to the RBP to deliver to LNG) or from the Arrow Surat reserves, addressed above.

While the Incitec load is uncertain, any redirection to RBP Westbound service would be offset by an equal reduction in Incitec's demand for RBP Eastbound service.

ACIL Allen therefore sees no prospect for use of RBP Westbound service by current major domestic gas users that has not already been taken into account.

3.6.2.5 *Spot market traders*

ACIL Allen considers that most of the parties likely to participate in trading at the Wallumbilla Hub will be LNG project participants, gas retailers or independent gas producers and so will have been captured in the preceding analysis. However, these parties might make use of RBP Westbound service outside their normal transportation operations, purely to facilitate Wallumbilla Hub trading operations.

ACIL Allen notes that the average volume of spot gas traded on the Wallumbilla Hub during 2014 (first year of operation) was 5.3 TJ/day, rising to an average of 9.7 TJ/day over the first half of 2016. The maximum volume traded on any day since market opening has been 60 TJ/day, with a high level of volatility evident. ACIL Allen assumes that:

- one or more parties will commit, in aggregate, to take 10 TJ/day of firm RBP Westbound service in order to accommodate the average volume of trade on Wallumbilla Hub; and
- one or more parties will use, in aggregate, up to 50 TJ/day of non-firm RBP Westbound service in order to meet peak day trading requirements on the Wallumbilla Hub. The probability of this level of non-firm service being required on any given day will be moderate (between 10 and 25 per cent, for which ACIL Allen adopts an 18% midpoint).

ACIL Allen notes that 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.

Following the calculation methodology above, this would translate to a Long Term Firm equivalent of 24.525 TJMDQ/day.

3.6.3 *Summary – Westbound demand forecast*

The Westbound load forecast is summarised below.

Table 3.10: Summary – RBP Westbound service demand forecast

Prospective RBP Westbound Service User	Firm demand	Short term Firm Peak	Short Term Firm Probability	Comments
LNG	0	120	5%	Any 1 of the 3 LNG Projects could use all available Westbound capacity on rare occasions if normal supply routes are disrupted
Retailers	10	90	1%	AGL's remaining net gas entitlements ex Berwyndale (after GLNG and Mt Isa sales) = 6-5 TJ/d 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/d non-firm Westbound service for GLNG supply if BWP unavailable to meet GLNG deliveries
Other (non-LNG) producers	12	0	N/A	Kogan North injections to RBP at up to 12 TJ/d; allows for option to move this west
Major Domestic Gas Users	0	0	N/A	Swanbank E redirection of gas is from QGC Berwyndale (no Westbound 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	18%	Average spot volume in 2016 was 9.7 TJ/d 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
Total	**32 TJ/day**	**16 TJ/day**	**(probability weighted)**	

Together, the ACIL Allen forecast of Long Term Firm demand and probability-weighted forecast of Short Term Firm demand translate to a Long Term Firm equivalent of 48 TJMDQ/day.

3.6.4 *APTPPL Westbound demand forecast*

APTPPL considers that ACIL Allen has undertaken a methodical, thorough and complete review of the types of shippers that might demand the RBP Westbound service, their demand drivers, the alternatives available to them, and the potential extent of their demand.

APTPPL supports the ACIL Allen analysis and submits that it is clearly compliant with Rule 74.

However, APA's commercial staff are in constant contact with gas industry participants in the SE Queensland region. While APTPPL supports the ACIL Allen forecast, it is of the view that there is some scope in the marketplace to out-perform relative to the ACIL Allen forecast.

APTPPL has therefore adopted a more aggressive Westbound load forecast for the purpose of determining tariffs in Chapter 10 as shown below.

Table 3.11: Forecast Long Term Firm equivalent demand calculations

	2017-18	2018-19	2019-20	2020-21	2021-22
ACIL Allen recommendation	48.0	48.0	48.0	48.0	48.0
APTPPL Westbound demand forecast	**39.9**	**58.3**	**75.8**	**75.8**	**74.9**

It should be noted that adopting this higher demand forecast places APTPPL at significant risk of not being able to recover its allowed revenue.

3.7 Summary

The total Long Term Firm equivalent load forecast is presented below.

Table 3.12: Forecast Long Term Firm equivalent demand

TJMDQ/day	2017-18	2018-19	2019-20	2020-21	2021-22
Eastbound Long Term Firm	156.5	134.5	115.8	116.1	116.2
Power Generation	3.58	7.19	8.42	8.07	8.88
APTPPL Westbound demand forecast	39.9	58.3	75.8	75.8	74.9
Long Term Firm Forecast (TJMDQ/day)	**200**	**200**	**200**	**200**	**200**

This chapter has estimated a base case Long Term Firm equivalent demand forecast of 160.1 TJ/day, declining to 125.8 TJ/day for the RBP Eastbound service, and 39.9 TJ/day, rising to 75.8 TJ/day Long Term Firm equivalent, for the RBP Westbound service.

This forecast assumes the continued operation of the Incitec Pivot Gibson Island fertilizer plant, and the continued closure of the Swanbank E power station. Sensitivity analysis has been performed on these assumptions.

In practical terms the direction-ambivalent nature of the proposed RBP Reference Service means that the demand forecast for the entire pipeline is 200 TJ/day. This will allow for some offsetting variations in demand between the Eastbound and Westbound services over the course of the access arrangement period.

In chapter 10 APTPPL calculates the tariff for Long Term Firm capacity on the basis of an assumed aggregate Long Term Firm-equivalent capacity reservation of 200 TJ/day. This places APTPPL at considerable risk in terms of the quantity of load migrating from a Long Term Firm capacity reservation tariff to a short term tariff. To the extent more "peaky" loads migrate to Short Term Firm tariffs (and therefore only pay for gas transportation actually used), APTPPL will recover less revenue than forecast.

4 pipeline asset management and planning

This chapter provides an overview of APTPPL's long-term pipeline asset management strategy and direction, planning and governance processes and key documents.

4.1 Asset management policy and objectives

The purpose of the Asset Management Plan is to formulate management strategies and actions to ensure safe and reliable asset operation in order to meet legislative obligations for the intended life of the asset, while meeting APA Group's business objectives of maximising financial return, optimising lifecycle costs, relating maximum asset value and effective risk management.

4.1.1 Asset management policy and objectives

The RBP asset management policy and objectives provide the guiding principles and asset management philosophy for the operation of the pipeline as follows, this is best summarised from the Asset Management Plan:

> *The AMP is to formulate management strategies and actions to ensure safe and reliable asset operation in order to meet legislative obligations for the intended life of the asset, while meeting the Company business objectives of maximum financial return, lowest lifecycle costs, creating maximum asset value and effective risk management"*[23]

4.1.2 Risk management policy

Risk management is a key component of asset management. The RBP is operated within the overarching APA Group Risk Management Policy and framework.

Risk is inherent in all aspects of APA's business. The APA Risk Management Policy applies a consistent approach to the management of risks associated with all activities undertaken by APA.

[23] APA Group, Asset Management Plan, 30 June 2015, p3

The goal is to cost effectively manage risk through identification, assessment and active management and mitigation of potential outcomes. APA maintains a system of risk management appropriate to the level of risk considered acceptable by the APA Board, which is based on the international risk standard AS/NZS ISO 31000:2009 (Risk Management – Principles and Guidelines).

APA is committed to a culture where risks that could affect our shareholder value, employees, stakeholders, the community, the environment, our reputation, our operating assets, our financial and legal status, or prevent the achievement of our objectives are well managed. APA will manage such risks by:

- Complying with all applicable regulatory and legislative requirements;
- Educating and involving our employees and stakeholders in the process of risk management;
- Articulating the roles and responsibilities of the different controls and individuals within the risk management process;
- Prioritising risk management according to likelihood (probability) and the consequence (impact) of risks, with appropriate consideration of controls and their effectiveness;
- Developing action plans which assign responsibilities and accountabilities to minimise high level risks;
- Incorporating risk management into our strategic plans, project plans, budgets, overall decision making and operating philosophy;
- Undertaking regular reviews of the risk management processes to ensure continuous improvement; and
- Regularly considering and updating the Company's risk registers and risk profile, including the identification of new business activities and unusual circumstances which may present new risks.

APTPPL operates in a potentially hazardous industry and recognises that this requires a rigorous and systematic approach to manage risk exposure. APTPPL is committed to ensuring that an integrated risk management system is applied throughout the organisation, one that will specifically address the risks of the industry.

4.2 Planning process

The Asset Management Plans and High Level Process Policy provides the overarching guidance for the asset management planning process.

4.2.1 Asset management planning process

The Asset Management process is a continuous loop as depicted in the flowchart at Figure 4.1. The process is divided into four major phases:

4.2.1.1 Issue identification

Issues are identified from a range of sources including asset assessments, change management processes and commercial considerations. They are assessed and potential solutions evaluated in terms of cost benefit and technical quality.

4.2.1.2 Scoping and prioritisation

Funding proposals are developed based on the evaluation performed in issue identification. Proposals are submitted for committee prioritisation and an options analysis is performed from a business perspective.

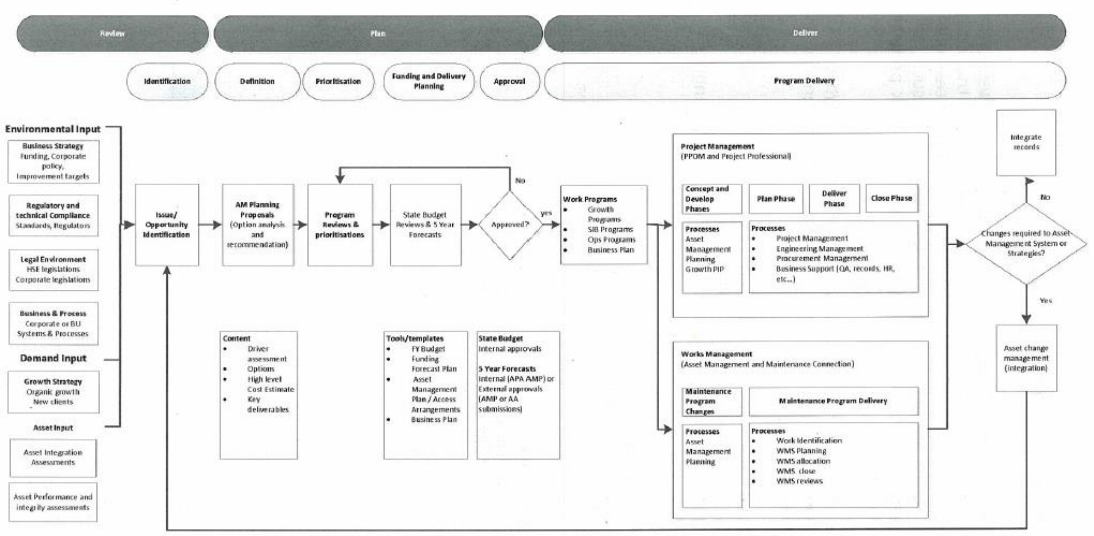
4.2.1.3 Funding approval

Final plans and associated budgets are submitted to the executive for national and strategic review and approval.

4.2.1.4 Work program delivery

Approved projects proceed through the five steps of the APA Project Management Framework.

Figure 4.1: Asset Management Process



4.3 Key planning and asset management documents

APTPPL has developed a number of planning documents to assist in the development and management of the pipeline, and to comply with relevant regulatory obligations. Key documents are:

- Asset Management Plan, including:
    - Lifecycle plan
- Pipeline Management Plan, including:
    - Safety and Operating Plan;
    - Environmental Management Plan; and
    - Records Management Plan.
- Emergency Plan

These are described in more detail below.

4.3.1 Asset Management Plan

The RBP Asset Management Plan (AMP) contains the rolling five year plan for nonroutine capital and operating expenditure for the pipeline, with some longer term projects such as intelligent pigging programs included. The AMP is limited to pipeline facilities and does not cover other facilities such as buildings, computers, desks, vehicles, small plant and equipment. The AMP is reviewed and revised on an annual basis. For this year the AMP was extended by one year to cover 2021/22 year in order to forecast capex and major expenditure projects for the duration of the access arrangement period.

The Pipeline Licence, AS2885 and other mandatory or statutory Standards and Regulations form the basis of compliance requirements addressed in the AMP. Other capital and operating works are determined by operator experience, integrity considerations and risk assessment.

A key component of the AMP is the Lifecycle Plan, which addresses pipeline, station, rotating equipment, plant and easement condition, and associated expenditure requirements.

The AMP also includes detailed project descriptions and costings.

4.3.2 Pipeline Management Plan

The Petroleum and Gas (Production and Safety) Act 2004 (QLD) under Section 675 requires each licence holder to develop a Safety Management Plan in accordance with the Regulations, the pipeline licence, and relevant ministerial directions. As APTPPL holds several pipeline licences across Queensland, South Australia and New South Wales, with similar regulatory requirements, it has prepared a combined Pipeline Management Plan (PMP) in compliance with its obligations across a number of pipelines, with Chapter 1 of this plan defining the Safety Management requirements. The complete PMP therefore applies more broadly than the covered RBP, with Chapter 3 relating specifically to QLD Operations.

APTPPL has prepared the PMP for the operation, modification and decommissioning stages of each pipeline. The PMP documents measures to ensure the:

- Protection of the relevant pipelines and associated facilities;
- Safety of the public;
- Safety of personnel working on the relevant pipelines;
- Safety of contractors;
- Minimisation of environmental impacts; and

- Effective incident management.

APTPPL maintains quality accreditation to AS/NZS ISO 9001 to achieve these objectives.

The PMP has been prepared in accordance with the requirements of the Petroleum and Gas (Production and Safety) Act and Regulation (2004 (QLD) and the guidelines set by Australian Standard AS 2885.3 Pipelines – Gas and Liquid Petroleum Part 3: Operation and Maintenance. The PMP contains all the requirements of section 675 of the Act including:

- a description of the plant, its location, operator, interaction with other plant and contractors and operations;
- organisational safety policies, safety responsibilities and structure;
- a formal safety assessment, including a description of measures undertaken to control risk;
- safety standards and operating and maintenance procedures applied in each stage of the plant;
- mechanisms for—recording, investigating and reviewing incidents at the plant;

In addition, the PMP also caters for the requirements of AS 2885.3 clause 4.2, which includes the following additional matters:

- Description of the pipeline system operation;
- Risk assessment in accordance with AS 2885.1 Pipelines – Gas and Liquid Petroleum Part 1: Design and Construction;
- Summary of operational and maintenance processes and procedures;
- Summary of the content of the emergency response plan;
- Summary of the records management plan; and
- Details of the audit schedule.

The overall structure of the PMP follows the outline of AS 2885.3 requirements.

4.3.3 *Records management*

APTPPL has a Records Management Plan in place describing the methods used to properly identify, control, and store records that are necessary to safely operate and maintain the pipeline. These records may assist in determining the fitness of the pipeline at any stage of the pipeline operating life.

The Records Management Plan includes:

- Identification of records to be maintained in accordance with legislative, statutory and contractual requirements;
- Retention requirements for those records;
- An outline of the appropriate storage methods to preserve required records; and
- Record maintenance policies so that obsolete records and procedures are removed from circulation.

The Records Management Plan has also been prepared to satisfy requirements under AS2885.3 for:

- Design, construction and commissioning records;
- Operation and maintenance records; and
- Decommissioning records if facilities are decommissioned.

4.3.4 *Emergency Plan*

An Emergency Plan is implemented and maintained. It ensures that incident response is correctly coordinated by focusing upon the response structure and field control to:

- Ensure a consistent and coordinated approach by emergency response personnel to any emergency;
- Control and limit any effect that the emergency may have on people, property and environment;
- Ensure priority communication of critical emergency information to affected stakeholders;

- Provide a sound basis for the training and assessment of emergency response personnel; and
- Provide a means for reviewing and improving the response techniques.

Emergency Response Plans define the minimum response required for an emergency arising on all pipelines and associated pipeline facilities. The Emergency Response Plan is tested and updated annually.

4.4 Expenditure governance

4.4.1 Budgets and expenditure approval processes

APA Group's Corporate Governance Statement has been developed in accordance with the Corporate Governance Principles and Recommendations issued by the Australian Stock Exchange Corporate Governance Council in August 2007. The statement sets out the principles and framework to be followed by the APA Group Board and senior management for the management of the business in areas such as risk management, ethical and responsible decision making and management and oversight.

APA Group Board responsibilities are set out in the Board Charter. Focusing on areas of particular relevance to this access arrangement, the APA Group Board is responsible for ensuring that effective audit, risk management, compliance and control systems are in place to protect APTPPL's assets and to minimise the possibility of the business operating beyond legal requirements or beyond acceptable risk parameters. The APA Group Board is also responsible for monitoring compliance with regulatory requirements.

APA Group has in place detailed capital expenditure governance processes to ensure that projects undertaken are prudent, efficient and in line with the overall strategy.

The capital expenditure budget is developed as an outcome of the AMP and includes concept plans, implementation schedules for major projects, and high level cost estimates for all proposed capital expenditure projects.

Replacement and upgrade capital expenditure works (otherwise known as 'stay-in business' (SIB) works) are included in the approved capital expenditure budget. Capital expenditure approval is required for all other capital projects and includes relevant information like identified needs, risk assessment, options considered, cost estimation, project justification and recommendation.

4.4.2 *Allocation between regulated and non-regulated services*

APTPPL has a robust process in place for allocating its costs and revenue between regulated and non-regulated activities to ensure that there is no cross subsidisation between regulated and non-regulated activities.

All expenditures are directly coded to job numbers created for non-regulated activities.

These expenditures are directly allocated to those non-regulated activities and are not included in the capital and operating expenditure discussed in the following sections.

Every APTPPL employee also completes a timesheet which must be submitted to their leader for approval on a weekly basis. These timesheets accurately record time spent on non-regulated activities and all such time is not included in recorded expenditure on regulated assets.

All capital expenditure is also directly allocated to the asset to which it relates based on actual capital spent.

4.4.3 *Procurement Policy and Procurement Guidelines*

Operating in conjunction with the key asset planning and management framework is the APA procurement policy.

All APA purchases of goods and procurement of services must be undertaken in accordance with the APA procurement policy and guideline.

APA's procurement practices are designed to ensure:

- financial, commercial, legal, operational, reputational, regulatory, environmental and occupational health and safety risks are determined, monitored, managed and reduced;
- goods and/or services meet specification and are delivered on-time at competitive prices from financially stable Suppliers;
- best value for money is realised, as evaluated on a total cost of ownership basis; and

- effective procurement processes and procedures, including rigorous ongoing contract management and Supplier relationship management are applied consistently.

It achieves this through a strict governance framework for expenditure approvals and competitive procurement processes.

4.4.3.1 Expenditure approval

The governance framework operates through delegated limits on authority. Any expenditure undertaken within budget must have approval from a manager with the appropriate level of authority.

4.4.3.2 Competitive procurement processes

Where the procurement value is or is likely to be greater than:

- AUD$100,000 APA or APTPPL must obtain competitive written quotes or proposals from a minimum of 3 relevant Suppliers; and
- AUD$200,000 APA or APTPPL must conduct a formal Request for Quote, Request for Proposal or Request for Tender as set out in the Procurement Guide.

The successful tenderer will then be selected based on the criteria established for assessing the proposals prior to conducting the tender, request for quote or request for proposal.

5 capital expenditure

This chapter provides summary information of actual and estimated capital expenditure undertaken in the current AA period, and forecast capital expenditure for the forecast AA period.

5.1 Background

As outlined in chapter 3 it is not forecast that demand will increase significantly in the forecast AA period. This demand forecast is reflected in the absence of any expansion capital expenditure in the capital expenditure forecast for the RBP.

The RBP was constructed in 1969 making it one of the oldest natural gas pipelines in Australia. It has been in continuous operation since then. The age of the pipeline has two consequences:

- As pipelines age they require more capital expenditure to keep them operating in accordance with the appropriate standards, licence conditions and laws.
- Pipeline technologies have improved over time including better quality steel, coating and cathodic protection available at the time of construction. Older pipelines used less advanced technology which means that these pipelines require more ongoing capital expenditure than their modern equivalents will in the same circumstances.

At the same time reviews of the required industry standards have resulted in tighter standards with regard to the safe operation of existing pipelines. A number of the actual and forecast capital expenditure projects are designed to address the requirement to meet changes to the Australian standards.

As a result of these factors the RBP has been experiencing increased capital expenditure associated with maintaining the safe operation of the pipeline in the current AA period. The need for integrity and safety capital expenditure is forecast to continue in the forecast AA period.

A discussion of the capital expenditure for the following periods is contained in this chapter.

- 1 July 2011 to 31 August 2012 from the AA period prior to the current AA period in section 5.4
- The current AA period from 1 September 2012 to 30 June 2017 in section 5.5
- The forecast AA period from 1 July 2017 to 30 June 2022 in section 5.10.

5.2 Asset classification

For the purposes of the AA revision proposal APTPPL classifies its capital expenditure according to driver as follows:

- Expansion capital expenditure, which is required to expand the capacity of the pipeline to meet demand both within the AA period and beyond;
- Replacement capital expenditure, which is required to maintain the integrity of the pipeline and includes items such as replacement of instrumentation (for example metering, telemetry, remote terminal units), pipeline hardware (for example pipes, meter valves, regulators and fittings), site capital improvements (for example fencing and security), and specialised major spares; and
- Stay in business capital expenditure which is all other capital expenditure necessary to provide pipeline services.

These classifications are identical to those used in the previous access arrangement submission to ensure consistency when comparing actual expenditure against the forecasts used to derive tariffs in the previous AA period, and comparing past and future expenditure in this proposal.

APTPPL does not use these classifications in its actual accounting and therefore some judgement has been applied in categorising historic and forecast expenditure into these classifications.

As noted in chapter 6 the current AA period started on 1 September 2011. APTPPL has presented capital expenditure data in this chapter in line with the AA period. That is, actual recorded expenditure for 2011/12 related to the period 1 July 2011 to 31 August 2012 (14 months), and actual recorded expenditure for 2012/13 reflected actual recorded expenditure for the period 1 September 2012 to 30 June 2013 (10 months).

The implications of the slightly later start to the AA period are also discussed in respect of the capital base roll forward in section 6.

5.3 Rules governing conforming capital expenditure

Rule 79(1) specifies that capital expenditure:

> *"… must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The capital expenditure must also be justifiable on a ground stated in subrule (2)."*

Rule 79(2) goes on to set out three main subrules for capital expenditure as follows:

(a) the overall economic value of the expenditure is positive; or

(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or

(c) the capital expenditure is necessary:

  (i) to maintain and improve the safety of services; or

  (ii) to maintain the integrity of services; or

  (iii) to comply with a regulatory obligation or requirement; or

  (iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)

The AER's discretion under this rule is limited such that the AER must not withhold its approval of capital expenditure if it is satisfied that it complies with the requirements of the law and is consistent with Rule 79. All forecasts and estimates must also comply with Rule 74.

5.4 Capital expenditure from previous AA period (1 July 2011 to 31 August 2012)

In its August 2012 final decision the AER included a total capital expenditure as incurred for the (notional) 12 months of 2011/12 of $49.4m nominal.[24] This is compared to the actual capital expenditure for 14 month period from 1 June to 31 August of $52.6m. The differential between forecast and actual is 6.6 percent.

Technically, to make an accurate comparison of actual capex to AER forecast requires both to be on a 14 month basis which would require allocating two months of the AER's 2012/13 forecast to its 2011/12 forecast. The very small difference between actual and forecast based on the AER's 12 month forecast means that APTPPL did not consider the materiality sufficient to warrant the need for this degree of spurious accuracy.

5.5 Capital expenditure during the current AA period (1 September 2012 to 30 June 2017)

5.5.1 *Total capital expenditure by driver*

Total capital expenditure by driver over the earlier AA period is set out in Table 5.1

Table 5.1: Capital expenditure by driver over the current AA period ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)
Extension/expansion capex	2.92	2.39	0.02	-	-
Replacement capex	0.53	2.13	3.87	4.43	6.03
Stay in business capex	2.42	5.91	19.09	5.44	12.19
Total capex	**5.88**	**10.43**	**22.98**	**9.87**	**18.22**

(f) forecast

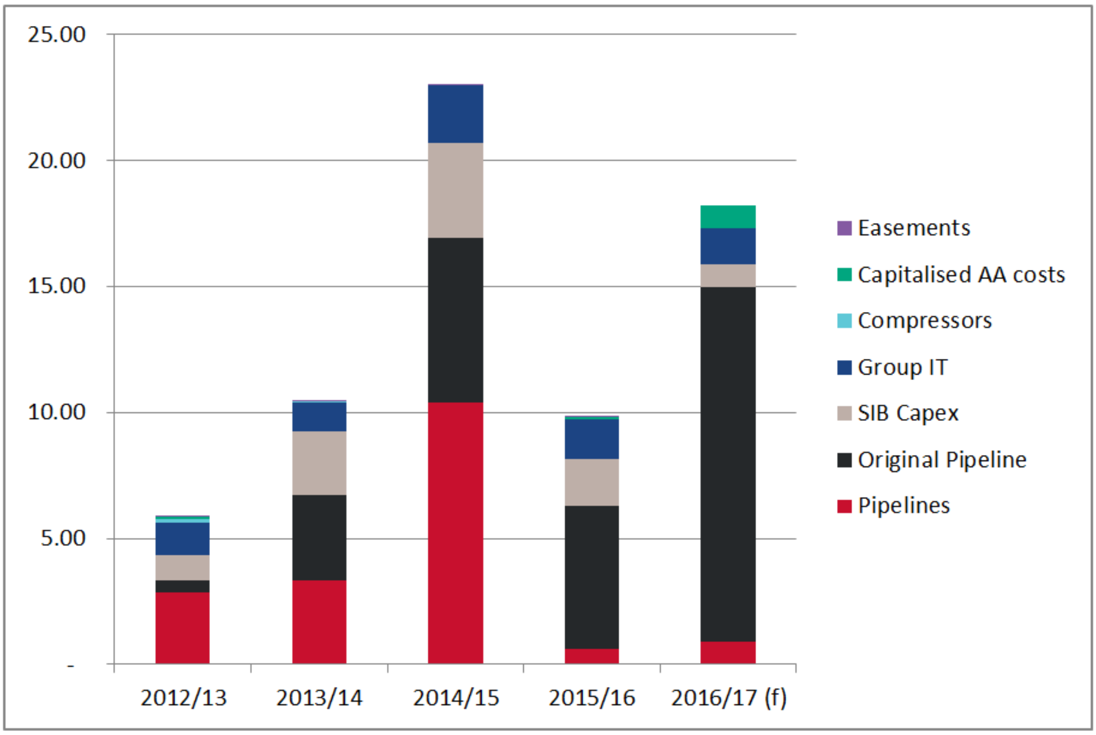
APTPPL's actual expenditure for the current AA period was above that approved by the AER for the period. The reasons for this difference are described in section 5.6.

[24] The AER's roll forward model appears to have used an inflation rate of 1.58% to calculate the 2011/12 value of their approved amount.

5.5.2 *Total capital expenditure by asset class*

Total capital expenditure by asset class over the current AA period is set out in Figure 5.1.

Figure 5.1: Capital expenditure by asset class over the current AA period ($m nominal)



(f) forecast

5.6 Details of capital expenditure projects from current AA period

Section 5.7 to 5.9 sets out the details of major capital expenditure projects that took place in the current AA period (2012/13 to 2016/17).

All projects undertaken during the current AA period were subject to the APTPPL planning and procurement processes outlined in chapter 4. The rigour of these processes ensures that APTPPL only undertakes expenditure such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted industry practice, to achieve the lowest sustainable cost in accordance with the requirements of rule 79(1).

5.7 Extension/Expansion capital expenditure

There were no new expansion projects in the current access arrangement period. There was some expenditure incurred on finalising the RBP8 project in the current access arrangement period.

5.7.1 *RBP8*

The Roma to Brisbane Pipeline Expansion 8, which comprised metro looping phase 1, the 400mm maximum operating pressure upgrade and the installation of a centaur 50 compressor at Dalby, was commissioned on 17 August 2012. This capital expenditure was approved by the AER for inclusion in the closing RAB at the end of the previous AA period.

There was some additional capex incurred to close this project out that occurred after that date and during the current AA period. This capex reflected both an ongoing legal dispute with one of APTPPL's contractors which was settled in 2012/13 which resulted in some legal fees but resulted in delays to APTPPL receiving invoices ($2m) and the normal close out costs associated with finishing a major project.

Table 5.2: Capital expenditure on RBP8 ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
RBP8	**2.92**	**2.39**	**0.02**	-	-	**5.33**

(f) forecast

This capital expenditure is on the same project and is consistent with the AER's draft and final determination in 2012 that the expenditure on RBP 8 is consistent with the National Gas Rules.

5.8 Replacement capital expenditure

There was some replacement capex projects from the current regulatory control period related to upgrades of pipeline integrity management and the replacement of the temporary crossing at Aquarium Passage with a long term solution.

5.8.1.1 *Aquarium Passage*

The Lytton Lateral is a 200mm pipeline and part of the Roma Brisbane Pipeline system, which was constructed and commissioned in 2010.

Due to delays in the Works Permit and Environmental Authority issuing relevant approvals, the planned crossing of the Aquarium Passage watercourse could not be completed as designed at the time of the construction of the Lytton Lateral.

In order to meet customer schedule requirements, a temporary crossing was installed using a reduced diameter (100mm) pipe installed in the Doboy Bridge. The nature of this crossing meant it had a short design life and inline inspection (ILI) of the lateral wasn't possible.

The Aquarium Passage project replaced the temporary crossing with a permanent 200mm crossing. This was required so inline inspection can be done on the Lytton Lateral and ensure its integrity for the design lifetime.

This work satisfies the requirement of rule 79(2)(c)(i), (ii) and (iii).

Under Schedule 5 of the Queensland Petroleum and Gas (Production and Safety) Regulations 2004 the RBP, inclusive of laterals such as the Lytton Lateral, is designated as a strategic pipeline. Strategic pipelines are specifically required by regulation 80 to be inspected by ILI within seven years of commissioning. The Aquarium Passage upgrade was necessary in order to comply with the Act in the required timeframe thus satisfying rule 79(2)(c)(iii).

Due to the location of the temporary crossing and the inability to undertake ILI on the line there was a significant risk that any faults in the pipeline would not be identified. This significantly increased the risk of unexpected pipeline failure. Therefore the capex was also necessary to ensure the ongoing safety of the pipeline and to ensure that gas could continue to flow to the user thus complying with rule 79(2)(c)(i) and (ii).

Table 5.3: Capital expenditure on Aquarium Passage ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Aquarium Passage	0.20	0.61	1.11	-	-	1.92

(f) forecast

5.8.2 *Integrity upgrade*

Expenditure on integrity upgrades both historic actuals and forecasts are covered in section 5.14.1

5.9 Stay in business

At the time of the last access arrangement submission APTPPL forecast the need for an upgrade to the Toowoomba metering and regulator station.

5.9.1 *Toowoomba Station upgrade*

The Toowoomba Meter and Regulator Station takes gas from the 250mm Wallumbilla to Bellbird Park (RBP Mainline) lateral, filters it, reduces its pressure and meters the flow to the Toowoomba township.

A number of elements of the site prior to upgrade did not meet current standards or safety requirements. This included the; regulator, filter and metering pipework, isolation valves, skids and a lack of redundancy on some critical assets. Some parts of the equipment at the station were also insufficient to meet peak demand.

APTPPL included, and the AER approved, the upgrade as a business case at the time of the 2011 access arrangement submission (Ref APPL12-AA-06-F). At the time the forecast for capital expenditure was expected to occur at the end of the current AA period and the cost estimate of $450,000 was based on the design and cost estimates for Redbank station.

However, as closer investigation and more detailed design revealed, there were a number of physical differences between the sites which resulted in an upgrade of much greater complexity at Toowoomba. The additional scope items were the replacement pressure vessel, and regulator skid (not just individual valves), and the civil works and pipe supports. The actual capital expenditure is shown in Table 5.4.

Table 5.4: Capital expenditure on Toowoomba Station Upgrade ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Toowoomba Station Upgrade	0.06	0.41	0.83	-	-	1.30

(f) forecast

Expenditure on the Toowoomba Station and accepted by the AER as being consistent with the National Gas Rule 79.

There were also a number of projects undertaken on the RBP that were not forecast at the time of the last access arrangement submission. These projects included construction to facilitate bi-directional flows on the RBP and expenditure to restore the pipeline following floods and land slips in 2013 and 2014. Each of these projects is discussed in more detail below.

5.9.2 *Bi direction capex*

This project involved the construction of assets to facilitate westbound gas flows on the RBP by creating a westbound connection point at Wallumbilla.

Prior to the capital expenditure, the RBP and SWQP were connected by a 16 inch pipeline. However, the RBP licence did not permit westbound flows, there was no means to measure westbound gas flows and the pipework and associated equipment had only been designed for eastbound flows.

In 2014/15 APTPPL commenced the capital expenditure to modify the pipework connecting the RBP to SWQP in order to facilitate westbound flows. In particular this work:

- Updated the RBP licence
- Installed a new process skid comprising valving, gas strainers, ultrasonic flow metering and gas chromatograph to receive and measure westbound gas from the RBP
- Installed two new piping connections to direct the westbound gas to two different destinations
- Removed a check valve and other equipment only designed for eastbound gas flows from a meter run

- Installed a new flow control valve with back pressure and flow control capability
- Installed a new control panel, instrumentation and cabling, and updated existing facility control logic to incorporate the new flow paths.

The capital expenditure for this project is set out in Table 5.5 below.

Table 5.5: Capital expenditure on bi-directional facility ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Bi-directional	-	-	7.55	0.61	-	8.16

(f) forecast

At completion this project provides a westbound capacity of 120TJ.

This expenditure is justified under both rule 79(2)(a) and (b) as discussed below.

As noted in section 3.6 the short duration that it has been available and the volatility of westbound flows to date mean that the westbound demand on the RBP is such that it is currently difficult to accurately forecast demand.

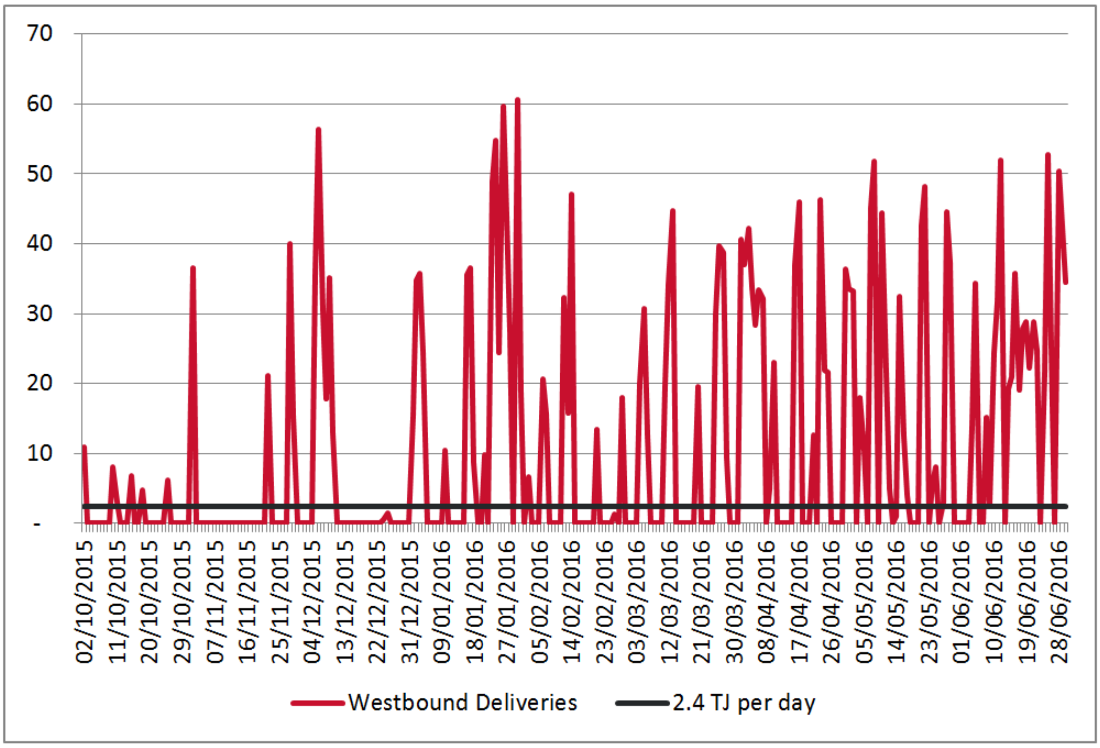
However, due to the level of capacity provided by the capital expenditure it was expected that the present value of revenues to be derived from the westbound gas flows over the life of the asset will be greater than the approximately $8.2m spent constructing the asset.

If APTPPL calculated the required TJ per day based on a real reference tariff of $0.71 per GJMDQ/day[25] on average it would require only 2.4 TJ/day to be transported over 20 years in order for the project to breakeven in NPV terms under 79(2)(b).

Westbound flows to date, although over a very short time period, support that this is achievable.

[25] This is the forecast 2014/15 tariff from the RBP AA Final Determination PTRM Model. This would represent the best expected tariff at the time of the commencement of the project. This means it represents the best basis on which to calculate the NPV.

Figure 5.2: Chart of Westbound gas flows on RBP to 30 June 2016(TJ per day)



Even should the AER not accept the inclusion of the capex under 79(2)(b), it should recognise that it is even more likely that the capex is justified under rule 79(2)(a). A user will only buy a service if the value of that service to them is greater than its cost. So for every TJ that flows westbound a greater value is being extracted by the user of that service. This in turn lowers the number of TJs required to flow westbound to justify the capex under 79(2)(a).

In the alternative, if the AER does not believe this capex satisfies the requirements of Rule 79, APTPPL submits that the capex should be recorded as speculative capital expenditure. APTPPL notes that this would also require that the AER not consider the volumes associated with the westbound service, a service only possible as a result of this capex, as part of the regulatory determination.

5.9.3 Emergency works

In 2011 flooding caused damage to the RBP. The capital expenditure as a result of this damage was included in the capital base at the start of the current AA.

Unfortunately there was further flooding and flood-related land slippage in 2013 and 2014 that also resulted in damage to the RBP. This required capital expenditure additional to that which had been identified at the time of the last access arrangement revision.

There were three major locations for this work across the current AA period. This capex related to:

- Marburg Range
- Sandy Creek; and
- Toowoomba Escarpment

The issues identified and solutions undertaken at each of the locations is discussed in more detail below.

5.9.3.1 *Marburg Range*

APA discovered a localised landslip in September 2011 in the Marburg Range area that had moved the pipe by 1-2 metres. This placed lateral pressure on the pipeline risking a sudden rupture.

APA quickly commenced work to secure the site and undertake a long term solution. As an early risk mitigation step, emergency works were done to depressurise the damaged section of pipeline and a temporary 250mm above ground bypass pipeline was constructed through the slip area.

As part of identifying the appropriate long term solution APTPPL undertook analysis of the area surrounding the pipeline that identified that the soil and ground conditions were likely to result in further slippages should the line be returned to its previous location.

APTPPL used horizontal directional drilling to relocate both the 250mm line and 400mm line beneath the slip area.

In the absence of this expenditure, given the real risk of further land slippages impacting on the pipeline, the risk of a loss of safety and integrity through a pipeline failure was high. The capex to avoid this was consistent with rules 79(2)(c)(i) and (ii).

5.9.3.2 *Sandy Creek*

Heavy rain led to creek flooding in early 2013 which caused erosion of the creek banks. The RBP pipelines were no longer protected by the earth of the creek banks. There was no breach of either the 250mm or 400mm pipes.

In order to mitigate the safety risk resulting from the exposure of the pipeline the maximum operating pressure was immediately reduced to 20% below maximum allowed operating pressure.

APA then undertook further analysis of possible solutions to the problem. As part of this work APTPPL identified damage to the pipeline, mainly dents on the side of the pipeline from rocks and other flood debris, and significant damage to the coating. The damage was assessed and repaired by composite wrap repairs, and coating was reapplied to replace the damaged coating section. The creek banks were repaired.

Unfortunately, further flooding at the same location only a few months later washed away the newly repaired creek banks and re-exposed the pipelines. Further studies confirmed that the natural creek bed level had been lowered by the floodwater action and the pipelines no longer had sufficient depth of cover. Target depth was identified as 2 metres below the lowest surveyed point of the creek bed and in-service lowering was selected as the most cost-effective option.

In the absence of this expenditure given the exposure of the pipelines and the subsequent likelihood of future issues with the creek the risk of a loss of safety and integrity through a pipeline failure was high. The capex to avoid this was consistent with rules 79(2)(c)(i) and (ii).

5.9.3.3 *Toowoomba escarpment*

The RBP crosses the Great Dividing Range at Mt Kynoch, near the city of Toowoomba. Both the 250mm and 400mm lines are located in the same easement through the crossing, with around 5 metres separation.

Following the catastrophic Queensland flood events of 2010/11, a loss of containment failure occurred on the 250mm line around 20 metres downstream of the railway crossing. This was repaired by depressurizing and purging the pipeline, performing a localized cut out and pipe replacement with emergency pipe from APA's stocks, then reinstatement. At the same time the 400mm line suffered severe washouts on the slope, requiring slope reconstruction in conjunction with major railway embankment repairs.

In 2014, APA experienced a second pipeline failure on the 250mm line about 140 metres downstream of the railway. This involved an uncontrolled gas leak, and required shutdown of pipeline for approximately 6 weeks. The cause of the pipeline rupture was identified as a creep landslide imposing bending load on pipeline.

When the leak was detected, the railway was closed temporarily until the gas leak was brought under control. Significant earthworks were required to remove landslide material from the pipeline corridor before the pipeline could be accessed for repair. The pipeline was repaired by a 70 metre cut out and pipe replacement.

APA immediately carried out analysis of all RBP pipeline sections for similar pipeline strain events, as this technology had become available from APA's inline inspection vendor. As part of this process, further bending strain and circumferential cracking was discovered in August 2014, at the railway crossing immediately upstream of the 2011 repair section.

Due to the obvious deformation of the pipeline and the casing and the difficult site conditions, construction of a replacement railway crossing was not possible. A reduced-diameter insertion repair was used. This allowed the 250mm line to be re-commissioned in December 2014.

The capex is consistent with rule 79(2) of the National Gas Rules as it is necessary in order to maintain and improve the safety of services (Rule 79(2)(c)(i)) and it is necessary in order to maintain the integrity of services (Rule 79(2)(c)(ii)). This is because this expenditure rectified the immediate containment failure in the Toowoomba ranges. In the absence of this expenditure the pipeline would have posed a threat to the wider community, in particular the rail crossing. It would also have been unable to continue in service. This capex addressed both safety and integrity issues.

5.9.3.4 Insurance Proceeds

APTPPL has insurance for industry specific risks. As a result of the flood damage to the RBP, APTPPL received compensation from its insurer (insurance proceeds). The insurance proceeds are set out in Table 5.6 below.

The insurance proceeds were deducted from the capex prior to the capex being added to the capital base.

Table 5.6: Capital expenditure on flood rectification works ($m nominal)

Capital Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Marburg Range	-	-	8.79	-	-	8.79
Sandy Creek	0.27	4.42	0.02	-	-	4.71
Toowoomba Escarpment	-	0.03	2.80	-	-	2.83
Other	0.10	-	0.01	-	-	0.11
Total Emergency Works Capex	0.37	4.45	11.62	-	-	16.44
Insurance						
Insurance proceeds netted off -	0.27 -	2.66 -	6.04	-	- -	8.96
Total						
Capital Expenditure less insurance proceeds	**0.10**	**1.79**	**5.58**	**-**	**-**	**7.48**

(f) forecast

5.9.4 *SCADA upgrade*

Supervisory Control and Data Acquisition (SCADA) is a system for remote monitoring and control that operates with coded signals over communication channels. This allows remote monitoring and operation of the pipeline.

The older system that APTPPL was using in Queensland had a number of issues. It:

- was only capable of running in older Microsoft windows environments
- had compatibility issues with modern trouble shooting and monitoring software
- had security and maintenance issues.

Alternatives to the ClearSCADA system also had compatibility issues with the other software systems that APA use to manage the RBP.

So APTPPL upgraded the SCADA system to a system compatible with the systems utilised by APA for other pipelines. This had the benefits of:

- Shared hardware reducing the need for separate service contracts and hardware upgrades.

- Shared software licenses instead of additional expensive standalone licenses
- Shared internal support instead of additional support by external contractors
- Multiple application users (removal of key personnel risk)
- Consistency with other applications used for the RBP such as Historian.
- Reduces operational risk associated with the different platforms and conventions across APA
- Reducing security and maintenance risk by using standard hardware, software and network architecture.

This capital expenditure is justified under rule 79(2)(c)(i) and (ii); this is because a failure of the SCADA system could result in the following negative consequences:

- Loss of remote control (open/close valves, start/stop compressors, change of operating setpoints)

It would also mean that there would be longer term consequences as:

- Loss of pipeline data if the failure was for an extended period (metering, pressure, temperature)
- Critical sites would potentially need to be manned 24hrs per day for any manual controls
- Metering data would either need to be collected manually once per day or estimated

Moving to ClearSCADA reduced the risks posed by a disruption to the SCADA system thereby satisfying the requirements of rule 79(2)(c)(i) and (ii).

Table 5.7: Capital expenditure on SCADA upgrade ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
SCADA upgrade	-	**0.40**	**0.57**	-	-	**0.97**

(f) forecast

5.9.5 *Flow Control and Remote Telemetry Unit upgrades*

The RBP system is operated, monitored and controlled by a remote control room, which communicates via a SCADA system to the individual site control systems at the various receipt, metering, compression and delivery stations along the pipeline.

The hardware at the stations prior to the upgrade were old and out of date with the station controllers based on 25 to 35 year old technology and the flow computers based on 20 to 30 year old technology. The control system hardware had reached the end of its service lifetime.

Spare parts for this equipment were no longer available from vendors and there were only a small amount of spare parts in APA inventories.

APTPPL originally planned the upgrade to be a long term process with relatively few upgrades in any given year. However, following a number of failures which resulted in capacity impacts APTPPL recognised the risk of failure was greater than initially assessed and there was a need for earlier replacement of these systems and units. This had the additional benefit of permitting an optimised roll out of the new flow controllers (FC) and remote telemetry units (RTU).

This upgrade is consistent with rule 79(2)(c)(ii) because, as the loss of capacity upon the failure of this equipment demonstrated, the ongoing consistent performance of FC and RTU are directly linked to the provision of pipeline services. In the absence of this expenditure there was a very real threat to the integrity of pipeline services.

Table 5.8: Capital expenditure on FC and RTU ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
FC and RTU	0.03	0.44	0.53	0.09	-	1.09

(f) forecast

5.9.6 *Corporate IT projects*

Since the start of the current access arrangement, APA Group has been required to undertake significant expenditure in IT systems to meet the ongoing needs of the business. These upgrades have been necessary for the RBP, and a proportion of expenditure for these projects has been allocated accordingly. The allocation for most of these individual projects is well below the materiality threshold for capital expenditure (most allocations are below $0.14 million). Some of the more significant projects (either from a financial or operational perspective) are set out below.

In all these cases, the proportion of the total costs borne by APTPPL is less than the stand-alone costs that would be incurred by APTPPL by running independent systems.

5.9.6.1 *Data Centre Project*

APA's internal data centres were inappropriate for APA's size and complexity. Recovery from an outage required manual steps that varied from system to system. The Data Centre Project delivered data capability of a standard consistent with APA's size and complexity.

The new data centre is more resilient and has better 'Infrastructure Platforms' to service APTPPL's business needs and cater for future RBP projects.

5.9.6.2 *Enterprise Asset Management System*

Effective and safe asset management is essential at APTPPL for the maintenance of its energy assets. APA previously used six standalone maintenance systems across the Networks and Transmission businesses.

This project involved development and migration to a new enterprise wide asset management system, supporting maintenance scheduling and recording of maintenance activities, inventory management and financial control. It also provides data to facilities analysis of equipment performance.

The previous system used by APTPPL had a number of problems. These were:

- hardware and software supporting these systems was near the end of its serviceable life.
- The system used was a comparatively simple 'stand-alone' system with substantially manual interfaces with APA's other management systems.

The new system enterprise asset management system adopted was superior as it was consistent with the other systems and platforms utilised by APTPPL, in particular the shared stores system which enables improvements to just in time maintenance practices.

5.9.6.3 *APA Gas Grid*

The APA Gas Grid (Project Colin or Energy Components) project comprises a number of functions which seek to transform APA Group's management of its gas assets. The project comprised of a new web-based customer interface to provide metering, billing and contractual information for users, a nominations tool for transport of gas, customer invoicing capabilities and customer access to real time pipeline capacity information to support nominations.

5.9.6.4 *Financial Transformation System*

APA Group businesses have, over the years, utilised multiple finance systems and charts of accounts, reflecting numerous legacy systems. Until recently, APA Group had three different finance systems creating considerable complexity in managing financial reporting, analysis and controls. APA Group has undertaken a project to rationalise the previous suite of finance systems to deliver ongoing savings to the APA Group businesses.

Total expenditure over the earlier AA period for IT projects is set out in Table 5.9.

Table 5.9: RBP capital expenditure on Corporate IT projects

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Corporate IT allocated to RBP	1.29	1.15	2.28	1.57	1.41	7.71

(f) forecast

These projects are consistent with the rule 79(2)(c)(i) and (ii) as the ongoing operation of safe, secure and reliable IT programs for APTPPL are necessary to provide reliable and safe pipeline services. The replacement of out of date, inadequate, insecure and overly complex IT systems is consistent with the rule provisions.

The AER approved these projects in its final determination on the Amadeus pipelines access arrangement.

5.10 Forecast capital expenditure during forecast AA period (1 July 2017 to 30 June 2022)

Many of the same drivers that occurred over the previous AA period are expected to continue into the forecast AA period.

In particular the ongoing escalation in the capital expenditure required to maintain the operational capacity and safety of an aging asset is expected to continue.

In addition there will be capital expenditure required to bring the RBP into compliance with the changes to the Australian Standard AS2885.

5.10.1 Total forecast capital expenditure by driver

Total capital expenditure by driver over the forecast AA period is set out in Table 5.10

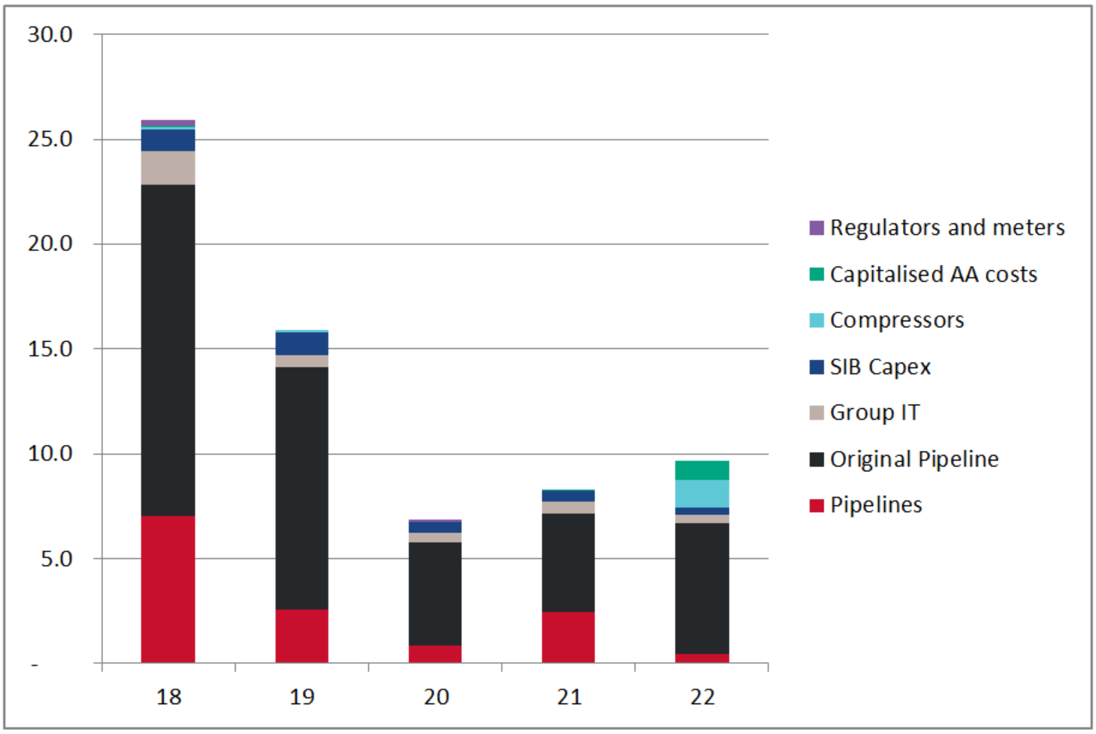
Table 5.10: Capital expenditure by driver over the forecast AA period ($m 2016/17)

asset driver	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Expansion	-	-	-	-	-	-
Replacement	8.70	10.25	5.46	6.81	6.38	37.59
Stay in Business	17.23	5.66	1.39	1.50	3.27	29.05
Total	**25.92**	**15.91**	**6.84**	**8.31**	**9.65**	**66.64**

5.10.2 Total forecast capital expenditure by asset class

Total capital expenditure by asset class over the forecast AA period is set out in Figure 5.3.

Figure 5.3: Capital expenditure by asset class over the forecast AA period ($m 2016/17)



5.11 Details of proposed capital expenditure projects for AA period

Sections 5.12 to 5.14 sets out the details of forecast capital expenditure.

5.12 Extension/Expansion capital expenditure

There is no expansion capital expenditure projects included in the forecast capital expenditure as forecast demand remains within the existing capacity of the RBP.

5.13 Replacement capital expenditure

Aspects of the pipeline integrity upgrade relate to replacement of sections of the pipeline coating and cathodic protection. This project is discussed in more detail in section 5.14.1

5.14 Stay in business

There are five major stay in business projects (>$1m) forecast in the next access arrangement. Together these projects account for 90 percent of APTPPL's forecast capital expenditure on the RBP. Each of these major stay in business projects is discussed in more detail below. More detail on these projects is included in the businesses cases in Attachments 6-2 and 6-3.

5.14.1 Pipeline integrity upgrade

As noted above the RBP includes over 800 km of buried pipelines, in sizes between 200mm and 400mm, the oldest of which was constructed in 1968-69 and has been in service ever since.

All buried pipelines are subject to coating deterioration and corrosion from the soil environment and require integrity management to comply with standards and legislation.

The RBP has particular characteristics such as its over-the-ditch tape coating system and its age that mean it requires significantly greater effort and expense in corrosion and integrity management that most other pipelines in Australia.

If insufficiently managed the corrosion and integrity issues could lead to pipeline failures affecting both public safety, given the pipeline traverses many populated areas, and security of supply to customers.

As would be expected from an aging pipeline the cost of integrity management is growing as more action is required to keep the pipeline in a safe operating condition.

This is because older pipelines have:

- been exposed to the environmental factors that cause metal loss (usually corrosion) and dents for longer, and
- less advanced technologies to combat metal loss and dents and their impacts on the safety and integrity of pipelines. In particular the coatings used on vintage pipelines tend to deteriorate more rapidly than modern equivalents, leading to risks of corrosion and cracking.

In relation to integrity management upgrades this submission will set out: the nature of the work that is included and how the elements inter-relate, the historic expenditure incurred by APTPPL and the basis of the forecast provided to the AER, and why this expenditure is consistent with the National Gas Rules.

5.14.1.1 *Integrity Management Upgrades*

The APTPPL integrity management programme to combat deterioration of the RBP is made up of three elements:

- Systematic investigation of the integrity of the pipeline through inline inspection (ILI);
- Detailed investigation and upgrades at specific locations through excavations; and
- Monitoring and upgrading of integrity devices such as cathodic protection.

These are discussed in more detail below.

Due to the significance of the pipeline integrity plan and the importance of ensuring that APTPPL gets it right, APTPPL had DNV-GL undertake a technical review of APTPPL's approach to integrity management on the RBP.

DNV-GL are amongst the foremost international experts in pipeline integrity management systems. The terms of reference for their engagement are outlined in the DNV GL report Attachment 6-2).

DNV-GL investigation found that

> *DNV GL supports APA's Pipeline Integrity Management Plan and its proposals outlined in this Business Case as that needed to manage the safety and operational integrity of this pipeline for the forecasted period.*[26]

[26] DNV-GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p2

Inline inspection

Inline inspection (ILI) comes in a number of different forms, each of which focuses on different threats to the integrity of the pipeline. The main forms used by APTPPL are:

- High-resolution magnetic flux leakage (MFL) inspection – detects corrosion, gouges, grooves, mill defects, girth weld anomalies and other metal loss features
- Geometry or caliper inspection – detects dents, ovality (out of roundness) and similar – can indicate 3rd party mechanical damage, rock dents from flooding or landslides, or dents remaining in the pipeline since construction
- XYZ (3-dimensional) inertial mapping – Maps the geographical position of the pipeline centreline and records any movement or change in shape since previous inspection. XYZ ILI enables curvature and strain analysis which is a key factor in mitigation of circumferential stress corrosion cracking.
- Electro-Magnetic Acoustic Transducer (EMAT) inspection – a recently developed technology that detects cracking and crack-like features. EMAT is used in the RBP to detect and manage stress corrosion cracking and longitudinal weld anomalies.

There have also been improvements in ILI technology over the life of the RBP such that APTPPL is able to identify dents and metal loss that were unlikely to be detected in previous ILI runs as well as the ability to undertake more sophisticated forms of ILI on smaller diameter lines.

Expenditure on ILI is driven by the type and number of ILI runs that are scheduled in any given year. This is driven in turn by the duration since the last round of ILI was conducted on the line and the condition of the line identified by previous ILI, integrity upgrade dig ups and CP monitoring. Lines identified as having more defects being scheduled more frequently for ILI to make sure any further deterioration is identified earlier. Typically, reinspection by ILI reduces the forward prediction of repair requirements and the cost of the ILI is small in comparison to the excavation and repair cost savings.

As noted in 5.8.1.1 under the Queensland Petroleum and Gas (Production and Safety) Regulations, APTPPL is obliged to carry out ILI on the RBP and its subsections within seven years of commencing operation and at least every 10 years after that subject to condition assessment of the line.

On the 400mm where relatively fewer metal loss and dents are being identified APTPPL has maintained the ILI schedule at the maximum of every 10 years. However, on the 250mm line where results of analysis demonstrate deterioration in the condition of the pipeline APTPPL's schedule has been reduced to every 5 years. These frequencies are supported by DNV-GL's assessment.[27]

Excavation and coating upgrades (integrity upgrade digs)

In order to maintain and improve integrity and safety of the pipeline when ILI, or any other assessment, identifies a dent or metal loss it is important that this defect is addressed. Usually this is done through integrity upgrade digs.

A typical integrity upgrade dig includes:

- Locating the pipeline, anomalies and nearby girth welds (for location reference purposes) by surveying and potholing
- Excavating a trench around the pipeline for safe access and to expose the pipeline for assessment and repair
- Removal of old and deteriorated coating from the pipe surface and abrasive blasting to prepare the surface for inspection
- Assessment of the anomalies by visual, physical and non destructive testing, and engineering assessment of the results to determine repair requirements
- 100% surface inspection for crack detection, using magnetic particle inspection or eddy current array inspection
- Pipeline refurbishment as required, to restore strength and upgrade the lifetime (e.g. fibre composite or steel sleeve, or pipe cut out and replacement for severe defects)
- Application of modern high-build epoxy coating to extend pipeline life, improve CP performance and prevent further corrosion or cracking

[27] DNV GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p5

- Reinstatement of the earth fill around the pipeline and reinstatement of environmental and surface treatment

The number of integrity upgrade digs are driven by the condition of the line as identified in ILI, previous digups and monitoring CP. There are three types of issues identified for a dig up:

- Dents;
- Metal loss, usually through corrosion; and
- Stress corrosion cracking.

Dents in pipelines are often associated with metal loss due to corrosion or gouging (mechanical damage). Dent/gouge combinations are known to be a high risk of pipeline failure. Dents with associated metal loss are at an elevated risk of stress corrosion cracking. Also, dents that impact the known low-toughness seam welds on vintage pipelines are at elevated risk of failure. Therefore, dig ups on dents are normally given priority over metal loss features. The dents themselves are prioritised based on:

- Depth and length
- O'clock position
- Seam weld/girth weld association
- Metal loss association
- Proximity to other dents, and
- Proximity to populated locations.

Metal loss features are also prioritised based on anomaly assessment. The metal loss dimensions, including depth (% of wall thickness), axial length, and grouping with other nearby metal loss features, as reported by the ILI tool are used to calculate theoretical burst pressures and resultant repair factors. Corrosion growth rates are calculated by comparing known features between ILI runs or excavation and inspection. A prioritised repair program is developed to ensure that all metal loss features are excavated and repaired before they grow to a size that may impact the safe operation of the pipeline.

Stress corrosion cracking (SCC) is a failure mechanism for pipelines where in the right conditions of pipeline material, external soil / coating environment, and sufficient tensile stress, cracks can develop and grow over time in the pipe wall. SCC can include both axial and circumferential cracking. Both types of cracks, to differing severities, have been found in RBP. Significant axial SCC has only been detected in areas of high pipeline strain such as ground movement areas,

An axial crack travels along and depth-wise through the pipe. Axial cracks provide the highest risk of rupture particularly if their length exceeds the critical defect length for the pipeline. Both leaks and ruptures could occur anywhere in the pipeline as internal pressure provides a significant tensile force. The Canadian Energy Pipelines Association (CEPA) has published a definitive guide on SCC management which is accepted worldwide. APA applies the CEPA guidelines apply and this threat is considered in the APA's SCC expert guide and the RBP SCC Management Plan.

APTPPL is undertaking SCC direct assessment at all digs; this involves 100 percent coating removal and crack detection by magnetic particle inspection or eddy current array, which increases dig cost and duration compared to standard ILI verification digs.

APTPPL efficiently manages its integrity upgrade digup program so that it addresses problematic features at the same time where they are in the same pipe spool. One digup may address multiple metal loss features and dents where they are located close together. This prevents repeat digups for different features of different priority.

APTPPL has the experience and capability to deliver the necessary integrity upgrade program of works. Reflecting the need for greater levels of intervention in the past two years the work has transitioned from ad hoc excavations and repairs by operations personnel, to a major project 'campaign' approach using APA's in house construction and project management team. This is expected to improve efficiency and reduce costs over the long term.

APA has brought experience in pipeline integrity upgrades to this work using lessons learned and management approaches from the Moomba-Wilton gas pipeline repair programme, which typically undertakes several hundred excavations and repairs per year.

Cathodic Protection

CP is a method of preventing the corrosion of buried or submerged pipelines by applying a DC electrical current. The current is applied using an external power source and anode, which forces the entire pipeline surface to become the cathode in an electrochemical cell and therefore prevents corrosion. Application of CP is a proven technology and a standard requirement for buried hydrocarbon pipelines. AS 2885.1 and AS 2832.1 are the relevant standards.

Where pipelines are experiencing coating breakdown or deterioration the reliance on CP becomes greater. This is because the increased exposed steel surface area requires additional CP current. Further, the increased current demand causes more rapid deterioration of protection potentials along the pipeline away from CP units.

5.14.1.2 Historic expenditure

ILI

As noted in 5.14.1.1, the main driver of ILI expenditure is the scheduling of ILI and the type if ILI undertaken. This can be seen in the historic actuals from the current period for 2013/14 to 2015/16. Throughout this period APTPPL undertook ILI on 7 sections of the 250mm line. This involved MFL, Geometry and XYZ ILI. Technology improvement meant that APTPPL undertook EMAT ILI on the 300 mm metro section in 2015/16, this was in addition to other forms of ILI APTPPL undertook in 2011 on the metro section.

Integrity upgrade dig ups

The results of the ILI demonstrated a large increase in the number of unreported dents and metal loss features. As noted above, analysis of the data from ILIs since 2011 identified deterioration in the RBP and this in turn has required more digups and coating replacement.

In 2014/15 and 2015/16 work was primarily addressing dents and metal loss features which may cause restrictions in maximum operating pressure, as these represent a more present risk to the integrity and safety of the pipeline.

However, the required number of digups continues to grow as the results of the ILI runs indicate further deterioration in the condition of the pipeline.

CP upgrades

As the coating condition deteriorates, RBP corrosion protection relies more heavily on CP. In 2013/14 APTPPL commenced a program of CP and CP telemetry upgrades. All CP systems on RBP are under heavy load due to the high current demand, particularly on the 250mm line.

Upgrade of CP systems including an increase in current output capacity of systems, and the installation of new CP systems to infill low protection areas between existing systems is required.

There are 69 CP units currently on the RBP. The typical anode bed life is 10-15 years meaning that on average 5 anode beds per year require replacement. DNV GL find this is a reasonable assumption to make given the age of RBP's CP units and the level of current demanded.[28] Replacement of anode beds enables greater current output from the CP systems in order to maintain adequate protection on the pipelines.

Due to increasing requirements and technology changes, the anode beds when upgraded often need to be physically larger and also need to be located further away from the pipeline to improve CP current distribution, meaning that additional land is required. Land requirements include easements and new or amended landholder agreements.

Awareness and repair of CP outages is vital and currently relies on field staff travelling the pipeline right of way fortnightly to check CP units. Remote telemetry brings the CP unit data (output voltage and current, pipe potential where available) back to SCADA enabling APA control room and engineering staff to see trends live and raise corrective work orders for field staff if power is lost or a CP unit fails. This removes the risk of unit/s being offline for weeks or months depending on field scheduling, ROW access, weather etc. This brings the RBP into line with current industry practice for pipeline CP monitoring.

[28] DNV GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p8

5.14.1.3 *Summary of historic expenditure*

The historic expenditure resulted in a pipeline that was more resistant to metal loss and dents. This reduced the risk of pipeline ruptures as a result of gas pressure exposing flaws in the pipe. This improves the integrity and safety of the pipeline consistent with the requirements of rules 79(2)(c)(i) and (ii).

Table 5.11: Actual and forecast capital expenditure on pipeline integrity management in current access arrangement ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
ILI	0.11	0.84	0.75	0.84	0.23	2.76
Integrity upgrade digups	0.26	0.59	2.33	3.72	5.02	11.91
CP upgrade	0.07	0.94	0.43	0.71	1.01	3.17
Other	0.10	0.02	-	0.14	-	0.26
Integrity Management Upgrade	**0.54**	**2.38**	**3.51**	**5.41**	**6.26**	**18.09**

(f) forecast

5.14.1.4 *Forecast expenditure*

ILI

APTPPL is forecasting EMAT ILI runs on the original 250mm line in 2017/18 and 2018/19 consistent with the APA national policies. The forecast also includes other forms of ILI on the 250mm line in 2018/19.

APTPPL is also forecasting ILI on sections of the 400mm line in 2019/20. This is consistent with both the APA national ILI policy and the legal obligations under the Queensland legislation.

APTPPL's approach is consistent with best industry practice as shown by the DNV-GL review.[29]

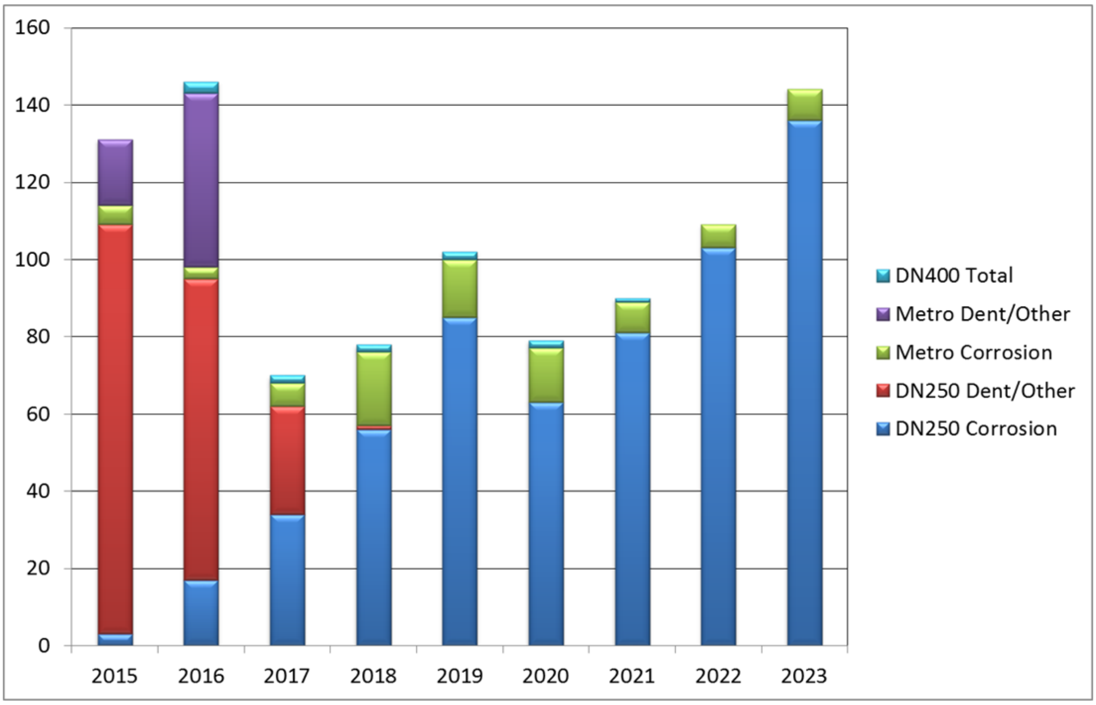
Integrity upgrade dig ups

The following chart shows the outcomes of the pipeline integrity modelling showing the number of excavations and repairs indicated for each calendar year, based on corrosion growth modelling in accordance with AS2885 and

[29] DNV GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p5

the relevant standards. This forecast is based on the results of integrity modelling undertaken by APTPPL consistent with best industry practice. DNV-GL in their review confirm that the number of digups is consistent with the number of anomalies that have been identified.[30]

Figure 5.4: Number of excavation forecast to be undertaken in each year.



Actual digs have been prioritised and scheduled according to risk levels, and sorted into financial-year dig campaigns. As a result of the large number of previously unreported anomalies, some excavations and repairs, which were recommended for repair in 2014/15 and 2015/16, will carry over into 2016/17 and 2017/18. Maximum operating pressure restrictions are being implemented on the 250mm and metro pipelines where required to manage any unrepaired anomalies.

It should be noted that the above graph is based on a reinspection of the 250mm pipeline in 2018/19, which is forecast to slow the growth in digup requirements in 2019/20 as previous work begins to have an effect. If

[30] DNV GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p6

reinspection is not done or results are not consistent with expectations, the required growth in the number of dig ups will increase.

The forecast number of integrity upgrade digups is outlined in Table 5.12

Table 5.12: Forecast number of integrity upgrade digups

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Integrity Digs	108	116	130	91	85	100

The expenditure on integrity upgrade dig ups is related to the number of digups forecast.

The methodology APTPPL has adopted to forecast the number of integrity upgrade dig ups is consistent with good industry practice as shown in the DNV-GL review.[31]

CP upgrade

As noted in relation to the historic CP upgrade capital expenditure as the coating on the pipeline deteriorates this puts further strain on CP. This requires more CP units or units positioned to reflect current needs to ensure ongoing coverage of the entire pipeline and bigger units to ensure adequate CP for those areas that are covered.

APTPPL will continue its program of CP upgrades into the forecast AA period.

5.14.1.5 *Forecast capital expenditure summary*

As a result of these factors APTPPL is forecasting the capital expenditure outlined in Table 5.14 for the RBP integrity management upgrade.

The other category is forecast capital expenditure on scraper trap modifications for ILI in 2017/18 and 2018/19 and the acquisition of a replacement laser scanner for pipeline feature assessment in 2020/21, based on a 5-year lifetime of the existing scanner.

[31] DNV GL, Technical Review of RBP Pipeline Integrity Management Business Case, August 2016, p6

Table 5.13: Forecast capital expenditure on integrity management upgrade ($m 2016/17)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
ILI	2.05	2.90	0.34	1.84	1.15	8.27
Integrity upgrade digups	5.41	6.11	4.07	3.76	4.33	23.69
CP upgrade	1.03	1.04	1.05	1.05	0.90	5.07
Other	0.20	0.20	-	0.15	-	0.56
Integrity Management Upgrade	**8.70**	**10.25**	**5.46**	**6.81**	**6.38**	**37.59**

This capital expenditure is consistent with rule 79(2) of the National Gas Rules as it is necessary in order to maintain and improve the safety of services (r79(2)(c)(i)) and it is necessary in order to maintain the integrity of services (r79(2)(c)(ii)). The RBP is aging and is being affected by metal loss and dents. As metal loss and dents are precursors for pipeline failure it is necessary that they be identified and resolved. Pipeline failure would result in sudden loss of pressure and an inability to continue to provide pipeline services until the issue has been resolved. Further, a sudden pipeline failure is potentially fatal to anyone in the area of impact in addition to the health risks associated with a loss of containment of the natural gas. Therefore, the expenditure is necessary to maintain the safety and integrity of pipeline services.

5.14.1.6 Asset Class

In the regulatory asset base APTPPL has categorised this capital expenditure as belonging to the pipeline asset class recognising the purpose of the expenditure was to upgrade the ongoing safety and integrity of the pipeline. APTPPL recognise that this expenditure could also be categorised as Stay in Business as it was necessary to maintain or restore the safety and integrity of the pipeline. However, it is the view of APTPPL that the work undertaken provides lasting benefit beyond merely restoring the pipeline to safe levels of risk related to the operation of the pipeline.

5.14.2 Deleted - confidential

5.14.3 *Urban risk reduction*

The Brisbane metropolitan section of the RBP comprises the eastern sections of the DN250 and DN400 pipelines, the Metro 300mm pipeline, partially duplicated for 6 km by the Metro Looping project, and a 200mm pipeline supplying Gibson Island. Since its construction in 1969, the RBP metro section right-of-way has been subject to extensive urban encroachment.

It is necessary to reduce the risk of the RBP metro section. As part of a long term strategy, operating pressure regulation is being implemented in addition to complementary protective barrier such as concrete slabbing being installed in identified critical areas in order to reduce the risk of pipeline rupture and improve public safety.

The work APTPPL is proposing to undertake is being made necessary by a combination of three factors:

- urban encroachment on the RBP;
- changes to the Australian Standard; and
- postponement of the RBP metro looping phase 2 and 3.

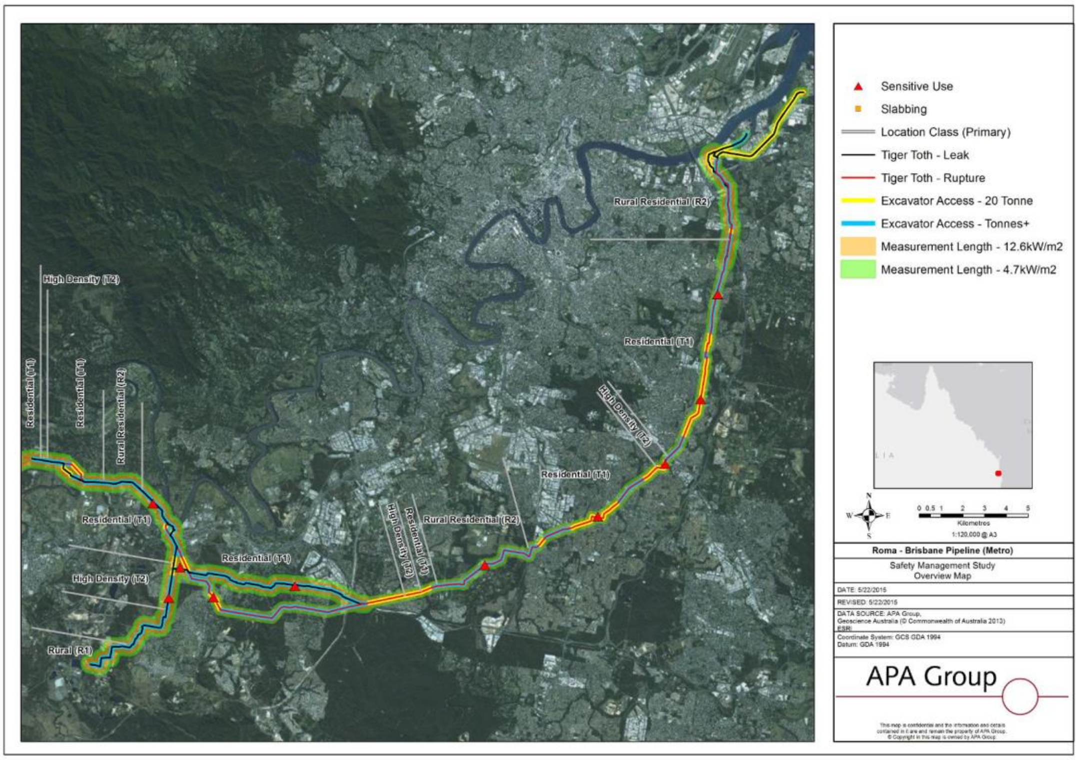
These factors are explained in more detail below.

5.14.3.1 *Urban Encroachment*

At the time of construction, the RBP traversed mostly rural areas. Since the time of construction, significant development has occurred particularly in the Brisbane outskirts, so that parts of the pipeline that were originally in rural areas are now surrounded by dense urban areas. To a lesser extent, growth in the towns along the pipeline such as Dalby and Toowoomba are also subject to urban encroachment.

As can be seen in the satellite image below, the metro section is located in dense, established suburbs of Ipswich and Brisbane, including Karalee, Riverview, Redbank, Collingwood Park, Camira, Forest Lake, Sunnybank, Eight Mile Plains, Wishart, Mansfield, Carindale, Carina, Tingalpa and Murarrie. A high proportion of the pipeline is located in road reserve, and therefore more exposed to other utility construction and maintenance threats, than in comparable pipelines in other major Australian cities.

Figure 5.5: Satellite image of the RBP location



5.14.3.2 *Changes to Australian Standard 2885*

Australian Standard 2885 is the standard that applies to the design, construction and operation of natural gas transmission pipelines.

In 2012 this standard was updated. Under AS2885.1 each pipeline segment is assigned a location classification. This classification is based on land use surrounding the pipeline and the operating pressure and diameter of the pipeline.

This standard requires physical and procedural mitigation measures to be applied during design and operation. The number and nature of physical and procedural measures required depends on the location classification.

For existing pipelines, the standard requires that they are assessed against the requirements of Clauses 4.7.2 and 4.7.3.

Clause 4.7.2 sets out the requirements for locations of particular sensitivity called High Consequence Areas (HCA). In High Consequence Areas pipeline operators are required to make it so that "the pipeline shall be designed such that rupture is not a credible failure mode."

Clause 4.7.3 requires that pipelines in High Consequence Areas meet certain specific technical requirements in relation to specific types of risks and consequences.

Where the existing pipeline does not comply with particular clauses, mitigation shall be assessed in accordance with Clause 4.7.4 and that risk is reduced to As Low As Reasonably Practicable (ALARP).

APTPPL identified a number of High Consequence Areas in the RBP metro section that can be identified as not currently ALARP and mitigation is needed.

5.14.3.3 Metro Looping Project Phase 2 and 3

In its determination for the 2012 to 2017 access arrangement the AER accepted the APA proposal in relation to RBP 8. This expansion involved the installation of an additional compressor at the Dalby Compressor Station (unit 2), duplication of a 6 km section of the Roma Brisbane Pipeline in the metro section (Metro Looping Phase 1) and a MOP upgrade of the 400mm pipeline.

At the time of the last AA submission APTPPL noted that the capacity of the RBP is likely to be constrained at some point by the capacity of the metro section and there would be a need to construct metro looping project (MLP) phase 2 and 3.

If the MLP 2 and 3 had gone ahead this would have enabled a pressure reduction along the length of the 300mm pipeline and relevant sections of the 250mm pipeline while still meeting the capacity requirements of Brisbane users. This would have reduced the risk of rupture on the metro section and thereby satisfied the requirements of AS2885 for many of the high consequence areas.

However, current forecasts do not support an economic case for the construction of metro looping phase 2 and 3 in timeframes consistent with the resolution of issues raised by urban encroachment and associated third party interference risks.

5.14.3.4 Analysis undertaken by APTPPL

As a result of these factors APTPPL has assessed the RBP against the requirements of the revised AS2885.

APTPPL carried out Safety Management Study (SMS) reviews of the RBP through 2014 (for the Metro section) and 2015 (for the remainder of the RBP), with an important focus on the High Consequence Areas requirements of AS 2885.1.

As a result of the risks identified in the SMS reviews in 2015 and 2016 APTPPL carried out a thorough risk reduction options assessment and ALARP analysis. This work identified the necessary steps that APTPPL has to undertake to bring RBP up to the revised standard.

5.14.3.5 Forecast Capital Expenditure

The analysis in the ALARP study concluded that the least cost and best risk outcome for 3rd party damage was to undertake MOP reduction where this could be done and to install physical protection where MOP reduction was not feasible.

This MOP reduction is to be achieved by

- An additional regulating station at Brightview on the 250 mm and 400 mm lines
- an additional mainline valve at Ellengrove on the 300 mm pipeline to enable the upstream section to run at a lower MOP.
- a new regulating station at Eight Mile Plains or Mt Gravatt to manage the downstream pressures. This location maximizes the length of pipeline covered by the MOP reduction in order to minimize the slab protection requirements.

These regulating stations and MLVs will adequately achieve the following target pressures:

- 250mm pipeline from Brightview to Bellbird park to 3,300 kPa;

- 400mm pipeline from Brightview to Swanbank and Ellengrove to 6,355 kPa;
- 300 mm metro pipeline from Bellbird Park to Ellengrove to 3,050 kPa
- 300 mm metro pipeline from Ellengrove to Eight Mile Plains to 4,200 kPa
- 300 mm metro pipeline from Eight Mile Plains to SEA to 3,050 kPa

Where MOP reduction is not possible then physical protection barriers (pipeline concrete slab or equivalent) will be constructed at the following locations:

- All High Consequence Area zones where excavator and auger access is credible, including road reserve, parkland and private properties (other than suburban residential yards), throughout the Ellengrove to Eight Mile Plains section of the metro pipeline. Approximately 7.7 km of barrier protection is required.
- Outside of the Ellengrove to Eight Mile Plains section – specific High Consequence Areas where the revised technical requirements of AS2885 clause 4.7.3 are not currently met; and
- At identified hot-spot locations where the pipeline may be particularly exposed to external interference for example road crossings and within road reserves.

Total capital expenditure for this project is set out in Table 5.14.

Table 5.14: Forecast capital expenditure urban risk reduction ($m 2016/17)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Urban risk reduction	**1.69**	**0.31**	**0.31**	**0.31**	**0.31**	**2.92**

The capex is necessary to maintain and improve the safety of services under r79(2)(c)(i) and is necessary to maintain the integrity of services under r79(2)(c)(ii) as the work is necessary to reduce the risk (frequency and consequence) of pipeline rupture to a level that is compliant with the industry standard AS2885. Pipeline rupture poses an immediate threat to safety of the general public and will result in an interruption to the provision of pipeline services on that line.

5.14.4 *Dalby Turbine overhaul*

Dalby compressor station is the main compressor on the RBP with Unit 2 comprising a Solar Centaur 50 gas turbine and centrifugal compressor set.

APA has national equipment regimes in place in the Enterprise Asset Management (EAM) system for Gas Turbine maintenance.

The Dalby compressor set was manufactured and supplied by Solar Turbines (the original equipment manufacturer or OEM). APA bases its Solar Gas Turbine/Compressor servicing on OEM recommendations. In addition to routine checks, the regime requires a unit overhaul at its end of life. The OEM recommendation for end of life overhaul is at 32,000 hours. This can be extended to a maximum of 50,000 hours before overhaul, provided that condition monitoring proves the turbine is suitable for ongoing operation.

APA's experience on the smaller Saturn turbines was that 50,000 hours was routinely achievable before overhaul. It is expected that the lifetime will be extended beyond the OEM recommendation however the overhaul will still likely fall into the forecast AA period.

Overhauling the turbine is in line with standard operating practice and similar overhauls have been approved in previous AA periods. Installed in 2012, this unit had more than 20,000 operational hours as of 2016. The 2022 forecast overhaul reflects the average usage of 5,000 hours per year to date continuing in the future.

The Solar pricing schedule currently has this overhaul cost as $1.33m which includes the overhaul of gas producer, power turbine and auxiliary gear box. The timing of this is reflected in Table 5.15.

Table 5.15: Forecast Capital Expenditure Dalby turbine overhaul

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Dalby Turbine Overhaul	-	-	-	-	**1.33**	**1.33**

The capex is consistent with rule 79(2) of the National Gas Rules as it is necessary in order to maintain the integrity of services (Rule 79(2)(c)(ii)).

The overhaul keeps the compressor at Dalby in operational condition. This reduces the risk of sudden compressor failure and loss of compression on the RBP when it is needed. Loss of compression would affect the ability to provide gas to users at times of high demand.

5.14.5 Group IT projects

APA has forecast IT projects in the current period which provides benefit to the RBP. The cost of these projects are allocated to the RBP on the same basis as all corporate costs are allocated to RBP. For more detail see section 8.2.2.2. After allocation only the applications and renewals project is significant enough to satisfy the major project threshold. The majority of these project are less than $0.06m.

5.14.5.1 *Applications and Renewals*

In order to ensure that the IT application systems are kept stable and at optimum performance, APA Group utilises an application lifecycle management methodology to determine upgrade timelines and priorities. An application upgrade plan is in place which is based on a stay in business program of work.

Software application assets are upgraded based on a 2 year cycle. There exist interdependencies between the various software applications which are integrated to support business requirements. This interdependency creates a working construct of software applications, and associated technology platform components, that are at risk if they are not maintained at compatible software release levels as prescribed by technology vendors.

This project is required to perform upgrades on existing IT assets and does not involve their replacement.

The Applications Renewal project is required to ensure that the RBP critical Information Technology (IT) applications are kept up-to-date over the next AA period.

The Applications Renewal project will involve systematically upgrading the nationalised software and applications that manage APA's operational business and pipeline services. The key objectives of this project are to:

- continue to maintain reliable, secure, compliant and efficient business processes and systems;
- preserve the ongoing integrity of APA pipeline services; and

- comply with regulatory and customer obligations.

Generally an application upgrade will involve not only the application upgrade itself, but also upgrades to the underlying associated technology platform components, assessment, design and implementation of any changes to configuration, customisations and integrations associated with the upgrades and complete testing of all impacted end to end processes.

Table 5.16: Integration update plan

Upgrade Projects	2017/18	2018/19	2019/20	2020/21	2021/22
Energy Components	X		X		X
Historian		X		X	
SCADA		X		X	
Middleware		X		X	
DBYD		X		X	
Field Data / Mobility	X	X	X	X	X
GIS		X		X	
EAM	X		X		X

The capital expenditure for this project is set out in Table 5.17.

Table 5.17: RBP capital expenditure on applications renewal

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Applications renewal	**0.43**	**0.53**	**0.43**	**0.53**	**0.43**	**2.34**

The key benefits from this project is to substantially reduce the level of risk of system(s) failure or integration between systems not working as required and improving the levels of systems security and data integrity. This means the risk of disruption to pipeline services and asset management are reduced thereby satisfying the requirements of rule 79(2)(c)(i) and (ii))

5.14.6 Business cases

APTPPL has provided the AER with business cases (Attachments 5-1, 5-2 and 5-3) that provide additional detail of the rationale for these projects. Business cases have not been prepared for minor and routine projects. The business cases cover 90% of forecast capital expenditure.

6 capital base

6.1 Opening capital base for the access arrangement period

In order to simplify the RBP capital base APTPPL has chosen to consolidate its asset classes commencing 1 September 2012.

6.1.1 *Changes to Asset Classes*

6.1.1.1 *Simplification of Asset Classes*

APTPPL has elected to reduce its number of asset classes from 25 Asset classes to 11 Asset classes. This will be achieved by merging a number of pipeline asset classes into one asset class and merging the separate compressor classes into a single compressor class.

This change will have no impact on total asset values, depreciation or remaining asset lives. APTPPL have chosen to change the number of asset classes as the artificial division of pipelines and compressors was leading to the need for APTPPL to subjectively divide capital expenditure across different asset classes. An example is inline inspection on the 400mm pipeline would have to be artificially split across asset classes looping 1, looping 2, looping 3, looping 4, looping 5 and looping 6. A similar problem was occuring in relation to expenditure on compressors. The consolidation is set out in Table 1.1 below.

Table 6.1: Asset class consolidation

Asset class in previous access arrangement submission	Proposed Asset class
Original Pipeline	Original Pipeline
Looping 1	Pipelines
Looping 2	
Looping 3	
Looping 4	
Looping 5	
Looping 6	
Lateral	
Lytton Lateral	
Pipelines/Laterals	

Asset class in previous access arrangement submission	Proposed Asset class
Dalby Compressor	Compressors
Kogan Compressor	
Oakey Compressor	
Condamine Compressor	
Yuleba Compressor	
Gatton Compressor	
Easements	Easements
Communications	Communications
Other	Other
Capitalised AA costs	Capitalised AA costs
Group IT	Group IT
SIB Capex	Stay in Business Capex
PMA	PMA
Regulators and meters	Regulators and meters
RBP Expansion 8	N/A

APTPPL has retained the original pipeline as a separate asset class as it has a different standard asset life to the other pipelines.

APTPPL has calculated the average remaining life of the assets based on the weighted average of remaining asset lives[32]. This approach was adopted so the remaining asset life of the separate asset classes is the same as that for combined asset class. The standard lives also remain unchanged.

6.1.1.2 RBP Expansion 8

In its last revised proposal submission in 2012 APTPPL noted that it had grouped the RBP Expansion 8 (RBP8) project costs into a single project file for ease of tracking costs and that when the RBP8 project was completed and

[32] The opening value is used for the purposes of value.

commissioned that APTPPL will classify the relevant assets to the correct asset classes.[33]

APTPPL has now undertaken this and allocated the RBP8. It has added the metro looping phase 1 to the pipelines asset class and the Dalby compressor Unit 2 to the compressors class.

The ability to do this demonstrates the advantage of the consolidated asset classes in the capital base. The metro looping phase 1 would not easily fit into any of the previous asset classes and would have necessitated the creation of a new asset class or the modification of an existing one. Under the consolidated asset classes it belongs in the pipeline asset class.

6.1.2 Opening capital base for the earlier access arrangement period

The AER included an allowance for capital expenditure in 2011/12 of $49.4 million ($nominal).

As noted above in section 5.4, the earlier access arrangement period started later than anticipated – on 1 September 2012 instead of 1 July 2012, such that the forecast for 2010/11 effectively relates to the period 1 July 2011 to 31 August 2012.

Rule 77(2)(a) requires APTPPL to establish the opening capital base at the commencement of the earlier access arrangement period. In line with the requirements of Rule 77(2)(a), APTPPL has completed the roll forward of the capital base to 31 August 2012 using actual capital expenditure in the 14 month period between 1 July 2011 and 31 August 2012 of $52.6 million ($nominal).

6.1.2.1 Changes to Rule 77(2)(a)

Changes to Rule 77(2)(a) implemented in October 2014, provide for an adjustment associated with the 'benefit or penalty' associated with any difference between the estimated and actual capital expenditure for values

[33] APTPPL, RBP AA Revised Proposal Submission, 28 May 2012, p35

included in the opening capital base established for the earlier access arrangement period.[34]

APTPPL has calculated this benefit at $5.97 million ($nominal), which it has applied to the closing asset value at 30 June 2016 to give effect to the return of the benefit APTPPL derived from this variation between estimate and actual expenditure.

6.1.3 *Conforming capital expenditure during current access arrangement period*

Conforming capital expenditure for the current access arrangement period is described in chapter 5 and is submitted in Table 5.1. As discussed in chapter 5, APTPPL considers its capital expenditure in the earlier access arrangement period to be prudent and efficient. Significant expenditure was required within the period to:

- address damage done to the pipelines as a result of flooding and land slippage;
- make the RBP bi-directional;
- undertake work to ensure the integrity of an aging pipeline

More detail on this expenditure is available in chapter 5

6.1.4 *Amounts to be added to the capital base under rules 82, 84 and 86*

6.1.4.1 *Capital contributions*

Rule 82 addresses the treatment of capital contributions by users to capital expenditure. The effect of the rule is that capital expenditure, to the extent contributed by users, is not eligible for inclusion in the capital base unless a mechanism is proposed under sub-rule 82(3) to prevent the service provider from raising increased revenue as a result of the inclusion.

[34] See from National Gas Rules version 22

APTPPL received a $95,218 in capital contributions in 2013/14These amounts were deducted from capital expenditure prior to the capital expenditure being added to the capital base.

APA received insurance payouts in relation to its flood damage suffered by the RBP in 2011 and 2013. As discussed in chapter 5 these amounts were subtracted from the capital expenditure prior to it being incorporated into the RAB.

Table 6.2: Capital Contributions in the current access arrangement period ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capital Contributions	-	0.10	-	-	-	0.10

6.1.4.2 *Speculative Capex*

Rule 84 relates to the formation of a speculative capital expenditure account, and how amounts included in a speculative capital expenditure account can be added to the capital base.

APTPPL does not currently have any expenditure in a speculative capital expenditure account, and did not roll any expenditure from a speculative capital expenditure account into the capital base during the earlier access arrangement period.

6.1.4.3 *Non conforming capex recovered through surcharge*

APTPPL did not undertake any non-conforming capital expenditure over the earlier access arrangement period that was recovered through a surcharge.

6.1.4.4 *Reuse of redundant assets*

Rule 86 relates to the re-use of redundant assets, and how, after the reduction of the capital base by the value of assets identified as redundant, should the assets later contribute to the delivery of pipeline services, the value of those assets can be returned to the capital base.

APTPPL did not re-use any assets during the earlier access arrangement period that it had previously identified as redundant, and therefore does not forecast any amounts to be added to the capital base under this Rule.

6.1.5 Disposals

Under rule 77(2)(f) the RAB is required to be reduced by the value of pipeline assets disposed of during the earlier access arrangement period.

There was a small amount of disposals relating to motor vehicles the proceeds on sales are set out in Table 6.3.

Table 6.3: Motor Vehicle disposals ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Motor vehicle proceeds on sale	0.11	0.07	0.04	-	-	0.22

APTPPL decommissioned four compressors in the earlier access arrangement period.

The decommissioned compressors were the:

- Saturn 20 compressor at Yuleba connected to the 250mm pipeline;
- Saturn 20 compressor at Condamine connected to the 400mm pipeline;
- Saturn 20 compressor at Dalby connected to the 400mm pipeline; and
- Saturn 20 compressor at Gatton connected to the 400mm pipeline.

APTPPL is proposing to physically remove these compressors from their current location in the forecast access arrangement period. While physically still at those locations they are not capable of being used to provide compression.

The Saturn 20 at Yuleba is no longer used due to changes in demand on the RBP.

The Saturn 20s at Condamine, Dalby and Gatton are no longer able to provide compression due to the installation of the Centaur 50 at Dalby and a pipeline MOP higher than their rated MOP.

There were no proceeds on disposal for these assets which means, consistent with rule 77(2)(f), the value of assets disposed was zero.

6.1.6 *Depreciation over the earlier access arrangement period*

The capital base has been rolled forward using the depreciation allowed by the AER in its 10 August 2012 Final Decision, as adjusted for outturn inflation, as shown in Table 6.4 and Table 6.5 below.

Table 6.4: AER forecast depreciation over the earlier access arrangement period ($nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
AER forecast depreciation	**- 15.27**	**- 16.50**	**- 17.96**	**- 17.69**	**- 16.82**

Table 6.5: Outturn depreciation and indexation over the earlier access arrangement period ($nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
AER forecast depreciation	- 15.27	- 16.50	- 17.96	- 17.69	- 16.82
indexation	10.44	12.27	5.66	5.72	8.70
net regulatory depreciation	**- 4.82**	**- 4.23**	**- 12.30**	**- 11.97**	**- 8.12**

6.1.6.1 *Depreciation of Compressors*

In order to simplify the operation of the RAB going forward APTPPL has moved depreciation between compressors and pipelines so that the RAB value of the disposed compressors was 0. This does not alter the depreciation shown in the tables above.

In order to increase the depreciation attributed to the compressors APTPPL has reduced the amount applying to pipelines. Over the life of the pipelines these changes net to zero. That is, the reduction in depreciation for these pipeline assets in the current access arrangement will be offset by increased depreciation over the rest of the life of the asset. Likewise the increase in depreciation for compressors now will be offset by a decrease in forecast depreciation for compressors in the forecast access arrangement period. APTPPL note that in the absence of this change the compressors subject to this change would all have been completely depreciated by the end of the forecast access arrangement period.

Allocating depreciation between asset classes in a way that does not change the total of depreciation is consistent with the approach adopted by the AER in its RBP access arrangement 2012-17 final decision[35] and reflected in the AER's final decision roll forward model[36] in respect to PMA. The depreciation for PMA was offset against some of the pipeline, lateral, looping and compressors asset classes.

6.1.7 *Indexation of the capital base*

As outlined above, the capital base has been indexed for outturn inflation, consistent with the AER's decision of 10 August 2012.

6.1.8 *Capital base roll forward 2012/13 to 2016/17*

The opening capital base for the access arrangement period is shown in Table 6.6. It should be noted that the opening capital base as at 1 September 2012 (the commencement of the prior Access Arrangement Period) is the closing capital base at 31 August 2012 (the end of the previous Access Arrangement Period), and that 2012/13 capital expenditure is for the 10 months from 1 September 2011 to 30 June 2012.

Table 6.6: Capital base roll forward 2012/13 to 2016/17 ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
opening capital base	417.67	418.82	425.35	436.68	434.87
plus net conforming capex	5.98	10.75	23.63	10.16	18.82
plus speculative capex					
plus reused redundant assets					
less depreciation	- 15.27	- 16.50	- 17.96	- 17.69	- 16.82
plus indexation	10.44	12.27	5.66	5.72	8.70
adjustment for previous period					5.97
closing capital base	**418.82**	**425.35**	**436.68**	**434.87**	**451.54**

[35] AER, AER Final decision | Roma to Brisbane Pipeline 2012–13 to 2016–17, August 2012, p42

[36] AER, AER Final decision - Roma to Brisbane Pipeline RFM –August 2012 (public), APA_Act 2007-11 Real

The closing capital base as at 30 June 2017 reflects the application of the AER's Asset Base Roll Forward Model from the commencement of the earlier Access Arrangement Period (1 September 2012) to 30 June 2017.

This includes an estimate for conforming capex incurred in June 2016 which will be replaced by actuals at the time of the revised proposal.

It is also necessarily includes a forecast of conforming capital expenditure for the 2016/17 year, which will be adjusted to reflect a best estimate of capital expenditure to 30 June 2017 in the revised Access Arrangement proposal.

APTPPL has applied the forecast depreciation to roll forward the capital base.

6.2 Projected capital base for the access arrangement period

Capital expenditure is discussed in chapter 5.

6.2.1 *Opening capital base in 2017*

The opening capital base as at 1 July 2017 reflects the closing capital base as at 30 June 2017 as discussed above.

6.2.2 *Forecast capital expenditure*

Forecast capital expenditure is addressed in section 6.5. In summary, forecast capital expenditure is shown in Table 6.7 below.

Table 6.7: Forecast capital expenditure over the access arrangement period ($2016/17)

	2017-18	2018-19	2019-20	2020-21	2021-22
OriginalPipeline (DN250)	15.82	11.59	4.90	4.67	6.23
Pipelines	7.03	2.55	0.86	2.44	0.45
Compressor	0.10	0.10	0.00	0.00	1.33
Regulators and meters	0.26	0.00	0.08	0.00	0.00
Capitalised AA costs	0.07	0.00	0.00	0.06	0.91
Group IT	1.61	0.59	0.47	0.58	0.43
SIB Capex	1.03	1.08	0.53	0.55	0.30
Total	25.92	15.91	6.84	8.31	9.65

6.2.3 *Non-conforming capital expenditure*

APTPPL does not forecast any non-conforming capital expenditure to be recovered through a capital contribution during the access arrangement period. APTPPL has no contractual agreements with parties where capital contributions are made by users to new capital expenditure pursuant to Rule 82.

6.2.3.1 *Surcharges and speculative capital expenditure account*

APTPPL does not forecast any non-conforming capital expenditure to be recovered through a surcharge during the access arrangement period.

APTPPL does not currently have any expenditure in a speculative capital expenditure account, and does not forecast any expenditure during the access arrangement period that it intends to add to speculative capital expenditure account.

6.2.3.2 *Disposals*

APTPPL does not forecast any disposals in the access arrangement period.

6.2.4 *Depreciation over the access arrangement period*

APTPPL has not changed the standard asset lives from those approved by the AER at the last review. The remaining asset lives, as at 1 July 2017, for forecast depreciation purposes are as shown in Table 6.8 below.

Table 6.8: Remaining Economic Lives

	Remaining economic life
OriginalPipeline (DN250)	35.0
Pipelines	64.3
Compressor	31.1
Regulators and meters	30.7
Easements	n/a
Communications	n/a
Other	n/a
Capitalised AA costs	4.7
Group IT	3.0
SIB Capex	5.0
PMA	3.0

Applying these remaining lives to assets in service as at 1 July 2017, and the economic asset lives to new capital expenditure, yields the depreciation forecast shown in Table 6.9 below.

Table 6.9: Forecast straight line depreciation over the access arrangement period ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Forecast straight line depreciation	15.45	16.72	17.75	11.42	11.76

6.2.5 *Indexation of the capital base*

The capital base has been indexed to allow for forecast inflation over the access arrangement period. As discussed in 6.3, the forecast inflation rate applied to the capital base is 2.3 per cent per year.

The forecast amount of indexation applied to the capital base is shown in Table 6.10 below.

Table 6.10: Forecast indexation of the capital base ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Forecast Indexation	9.03	9.45	12.05	12.09	12.34

6.2.6 *Projected capital base over the period*

The projected capital base for the access arrangement period is shown in Table 6.11.

Table 6.11: Projected capital base for the access arrangement period ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening capital base	451.54	472.26	481.97	483.75	493.75
plus indexation	9.03	9.45	12.05	12.09	12.34
plus forecast capex	27.13	16.98	7.49	9.32	11.09
less forecast depreciation	15.45	16.72	17.75	11.42	11.76
less forecast disposals	0.00	0.00	0.00	0.00	0.00
less forecast redundant assets	0.00	0.00	0.00	0.00	0.00
Closing capital base	472.26	481.97	483.75	493.75	505.43

6.3 Forecast inflation

APTPPL has used the method adopted by the AER in its previous regulatory decisions for forecasting inflation during the period of the revised RBP Access Arrangement. Inflation during this period is estimated from Reserve Bank of Australia short term inflation forecasts and, for years beyond the period of these forecasts, the midpoint of the Bank's target band for inflation. Estimation uses the geometric mean of data for 10 future years.

The AER has advised that this method of forecasting inflation produces a reasonable estimate for the following reasons:

- Reserve Bank of Australia research indicates that its one year inflation forecasts have substantial explanatory power;
- to the extent that the historical success of Reserve Bank monetary policy informs market consensus inflation expectations, the mid-point of the Bank's inflation targeting band would reflect longer term inflation expectations;
- evidence indicates that the Reserve Bank's control of official interest rates and commentary has an impact on outturn inflation and inflation expectations; and

- the method is simple, transparent, easily replicated and unlikely to be subject to estimation error.[37]

The most recent Reserve Bank of Australia inflation forecasts are summarised in Table 6.12.

Table 6.12: Reserve Bank of Australia CPI inflation forecast

	Jun 2016	Dec 2016	Jun 2017	Dec 2017	Jun 2018	Dec 2018
CPI inflation	1.0%	1.5%	1.5% - 2.5%	1.5% - 2.5%	1.5% - 2.5%	1.5% - 2.5%

Source: Reserve Bank of Australia, *Statement on Monetary Policy*, August 2016, page 67.

In this most recent forecast, the Reserve Bank has made greater use of ranges than has previously been the case. Using the upper limits, for June and December 2017, and for June and December 2018, with the midpoint of the Bank's target range (2.5%) for subsequent years, the geometric mean for a period of 10 years is 2.5%. Using the lower limits (and the mid-point of the target range), the geometric mean is 2.3%.

The Reserve Bank has observed in its August 2016 *Statement on Monetary Policy*:

> *Various measures of inflation expectations are lower than their long-run averages, but most are still consistent with the medium-term inflation target. It is possible that inflation expectations will be lower for longer than is currently anticipated.*[38]

APTPPL has, therefore, used 2.3% as the forecast of inflation for its proposed revisions to the RBP Access Arrangement.

6.4 Tax Asset Base

Rule 87A requires:

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[37] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2019, Attachment 3 – Rate of Return*, page 3-148.

[38] Reserve Bank of Australia, *Statement on Monetary Policy*, August 2016, page 71.

> *The estimated cost of corporate income tax of a service provider for each regulatory year of an access arrangement period (ETCt) is to be estimated in accordance with the following formula:*
>
> *$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$*

Where

- ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider;
- r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- γ is the value of imputation credits.

In order to calculate the estimated cost of corporate income tax, it is necessary to establish the amount of tax depreciation that can be deducted from taxable revenue to determine the amount of tax payable. As tax depreciation is based on different depreciation rates than those used for statutory accounting or regulatory purposes, the value of the Tax Asset Base (TAB) is likely to be different at any given point in time than either the statutory or regulatory asset base. It is therefore necessary to establish a TAB for regulatory purposes.

APTPPL has rolled forward the TAB in the earlier access arrangement period using the same principles as the normal asset base roll forward. That is, APTPPL has applied the AER's Asset Base Roll Forward Model adopting the opening TAB in the earlier access arrangement period, and rolled it forward using actual capital expenditure using the AER's PTRM methodology. As the TAB is not indexed, it was not necessary to update the roll forward for outturn CPI increases.

The TAB roll forward is shown in Table 6.13, and the forecast TAB is shown in Table 6.14.

Table 6.13: Tax Asset Base as at 30 June 2017 ($m nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
opening TAB	134.78	124.11	122.17	131.89	128.77
net additions	5.77	10.36	22.95	9.87	18.22
tax depreciation	- 16.44	- 12.30	- 13.23	- 12.99	- 12.42
closing capital base	**124.11**	**122.17**	**131.89**	**128.77**	**134.57**

Table 6.14: Forecast Tax Asset Base ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening TAB	134.57	148.13	150.07	141.70	137.69
Net additions	26.44	16.55	7.30	9.08	10.81
Tax depreciation	-12.88	-14.61	-15.68	-13.09	-13.36
Closing TAB	148.13	150.07	141.70	137.69	135.14

The TAB is then applied to determine the corporate income tax allowance derived for the revenue model as indicated in 9.5.

7 rate of return and value of imputation credits

The return on the projected capital base included in the total revenue is to be determined as the product of a rate of return, the allowed rate of return, and the projected capital base at the beginning of each regulatory year of an access arrangement period (Rule 87(1)).

The way in which APTPPL proposes to determine the allowed rate of return, guided by the AER's Rate of Return Guideline, is set out in this chapter of the submission.[39]

The value APTPPL proposes to attach to the franking credits available to equity investors under the dividend imputation provisions of Australian taxation law is also noted and discussed.

The allowed rate of return of Rule 87 is to be the weighted average of a return on equity and a return on debt. APTPPL proposes to estimate a single return on equity for the access arrangement period (July 2017 to June 2022), and a (potentially different) rate of return on debt for each of the regulatory years in that period. APTPPL proposes, by estimating a rate of return on debt for each regulatory year, to update that rate annually to reflect prevailing financial market conditions in each year of the access arrangement period.

The allowed rate of return used to determine the revised reference tariff set out in the proposed revised RBP Access Arrangement has been determined assuming that the rate of return on debt estimated for the first regulatory year of the access arrangement period applies in each of the remaining years of that period.

APTPPL's proposed (initial) allowed rate of return for the RBP Access Arrangement revisions proposal is 7.7%. The way in which APTPPL has established the proposed allowed rate of return is set out in sections 7.1 to 7.5 below.

Section 7.7 discusses estimation of the value of imputation credits, and explains APTPPL's gamma estimate of 0.25.

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[39] Australian Energy Regulator, *Rate of Return Guideline*, December 2013.

7.1 Gearing

The allowed rate of return of Rule 87 is to be the weighted average of a return on equity and a return on debt determined on a nominal vanilla basis (Rules 87(4)(a) and (b)). In a weighted average determined on a nominal vanilla basis, the weight to be given to the return on equity should be the proportion of equity in the total capital of the benchmark efficient entity (which is assumed to be financed by equity and debt). The weight to be given to the return on debt – the gearing – should be the proportion of debt in the total capital of the benchmark efficient entity.

Section 4.3.2 of the Rate of Return Guideline advises that the gearing of the benchmark efficient entity for which the weighted average of the return on equity and the return on debt is to be determined is to be 0.6.

APTPPL has therefore used gearing of 0.6 to calculate the nominal vanilla weighted average of returns on equity and debt which is to be the allowed rate of return for the proposed revisions to the RBP Access Arrangement.

7.2 Credit rating

Determination of a rate of return for a benchmark efficient entity with degree of risk similar to that of the service provider in its provision of references services, in accordance with Rule 87(3), requires a measure of credit risk.

Paragraph 6.3.3 of the Rate of Return Guideline proposes that this measure of credit risk be a credit rating of BBB+ from Standard and Poor's or the equivalent rating from another recognised rating agency. If financial data used to estimate the allowed rate of return do not reflect a credit rating of BBB+, or the equivalent, they are to be those which most closely approximate data for an entity with a BBB+ credit rating.

APTPPL has therefore assumed a credit rating of BBB+ for the benchmark efficient entity. Where financial data to be used in estimating the rate of return are not available for entities with that credit rating, APTPPL has used data for BBB rated entities.

7.3 Estimating the return on equity

This section of this chapter of the submission sets out APTPPL's approach to estimating the return on equity for the proposed revisions to the RBP Access Arrangement.

The foundation model of the Rate of Return Guideline – the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM) – is noted in section 7.3.1. The way in which APTPPL has estimated the return on equity using the SL CAPM is explained in sections 7.3.2 to 7.3.6.

APTPPL proposes that an initial estimate of the return on equity of 8.4% be used in establishing the allowed rate of return for the proposed revisions to the RBP Access Arrangement. This initial estimate will be updated during the access arrangement revisions approval process so that the rate of return on equity used in determining the allowed rate of return has been estimated having regard to prevailing conditions in the market for equity funds.

7.3.1 Foundation model

The Rate of Return Guideline identifies four quantitative financial models which may have a role in estimating the return on equity. These four financial models are:

- the SL CAPM;
- Black's Capital Asset Pricing Model (Black CAPM);
- the dividend growth model;[40] and
- the Fama-French Three Factor Model.

The SL CAPM is referred to as the "foundation model". It is to be the starting point for estimating the expected return on equity.

The Black CAPM is not to be used directly to estimate the return on equity. It is to be used only to inform estimation of the equity beta to be used in applying the SL CAPM.

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[40] APTPPL uses the singular term dividend growth model to refer to the class of financial models which can be used to estimate the return on equity as the discount rate which equates the present value of future dividends with the current share price.

Similarly, the dividend growth model is to be used to inform estimates of the market risk premium (MRP) to be used in applying the foundation model. It is not to be used for the purpose of estimating the return on equity itself.

Although the Fama-French Three Factor Model is a relevant financial model, the Rate of Return Guideline advises that it has no role in estimating the return on equity.

The SL CAPM explains the expected return, $E(r_j)$, on financial asset j, as the sum of the rate of return on a risk free asset and a premium for risk:

$$E(r_j) = r_f + \beta_j \, [E(r_m) - r_f],$$

where r_f is the return on the risk free asset, β_j is the beta for asset j, and $E(r_m)$ is the expected return on the market portfolio of assets.

Application of the SL CAPM produces an estimate of the expected return on equity from a current estimate of the risk free rate of return, and from a current view of the expected return on the market portfolio of assets. It produces the estimate of the return on equity required by Rule 87(7): an estimate made having regard to prevailing conditions in the market for equity funds.

The AER has noted that historical data may be used in estimating the parameters of the SL CAPM where those data are good evidence of forward-looking parameters. Historically based estimates that are clearly not representative of the forward-looking rate should not be used; they will result in biased estimates of the return on equity.[41]

7.3.2 *Risk free rate of return*

The risk free rate is the rate of return on a financial asset which is without risk. To estimate the risk free rate, a proxy for this riskless financial asset – the risk free asset – must be found from among the traded financial assets for which returns can be observed. The Rate of Return Guideline proposes that Australian Government securities with a term to maturity of 10 years be the

[41] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2019, Attachment 3 – Rate of Return*, page 3-198.

proxy for the risk free asset. The risk free rate of return is then to be estimated from the yields on these securities.

When estimating the return on equity, recognition will be given to conditions prevailing in the market for equity funds if, when applying the foundation model, the risk free rate is commensurate with prevailing conditions in financial markets at the commencement of the access arrangement period.

To remove the effects of "noise" from the estimate of the risk free rate, yields on Australian Government securities with the required term to maturity should be averaged over a period of between 10 consecutive business days and one year. To provide an estimate of the risk free rate which is commensurate with prevailing conditions in financial markets, this period should be as close as practicably possible to the commencement of the access arrangement period for which the allowed rate of return is being determined.

APTPPL understands the reasons for choosing the averaging period as close as practicably possible to the commencement of the access arrangement period, and anticipates that the AER will estimate the risk free rate for an averaging period which is close to the time of its making a final decision on the proposed revisions to the RBP Access Arrangement.

For preparation of the proposed revisions, a much earlier averaging period must necessarily be assumed. For the purpose of this revisions proposal, APTPPL has estimated the risk free rate as the average of yields on Australian Government securities with terms to maturity of 10 years over the period of 20 consecutive business days ending 29 July 2016.

APTPPL's estimate of the risk free rate of return is 1.94%.

7.3.3 Equity beta

Application of the SL CAPM, the foundation model of the Rate of Return Guideline, requires an estimate of beta for a benchmark efficient entity with degree of risk similar to APTPPL in respect of its provision of reference services using the RBP.

APTPPL's estimate of beta is 0.8.

This was the estimate of beta which the AER made for the purpose of estimating the return on equity for its Final Decision on proposed revisions to the RBP Access Arrangement in 2012.

In December 2013, the AER issued its Rate of Return Guideline and, following further work on the empirical estimation of beta by Professor Olan T. Henry in April 2014, the AER proposed a beta estimate of 0.7. However, Professor Henry's more recent work did not change the evidence on which the AER's earlier estimate of beta for the RBP was based.

Moreover, new evidence is emerging of an increase in the beta estimates obtained using data from the set of Australian energy utility firms used by the AER and others for the purpose of making those estimates. There is, then, no reason for concluding that the systematic risk of for a benchmark efficient entity with degree of risk similar to APTPPL in respect of its provision of reference services using the RBP has changed: the earlier estimate of beta of 0.8 should be retained.

7.3.3.1 Beta estimate of the AER's August 2012 Final Decision

In revisions to the RBP Access Arrangement submitted to the AER in October 2011, APTPPL proposed an estimate of beta of 1.0. APTPPL proposed that the systematic risk of reference service provision using the RBP was the same as the systematic risk of the market portfolio of risky assets.

The AER did not agree, stating in its August 2012 Final Decision on the revisions proposal:

> *An equity beta of 0.8 is more reflective of the risks involved in providing reference services than the equity beta of the average firm in the market.*[42]

This estimate of beta, the AER advised, was made taking into account the empirical estimates made by Professor Henry for the 2009 review of WACC parameters for electricity service providers. The AER had also considered a broader set of empirical analysis, including analysis provided by network

[42] Australian Energy Regulator, *Access arrangement final decision Roma to Brisbane Pipeline 2012–13 to 2016–17*, August 2012, page 23.

service providers, and found that it indicated a point estimate for beta of between 0.4 and 0.7. The AER concluded that an estimate just above this range was justified in recognition of the level of imprecision around beta estimation, and taking into account the desirability of stability in regulatory decision making over time.

The AER also noted, in August 2012, that other analysis, using different statistical techniques or different time periods, provided support for the range 0.4 to 0.7. In addition, cross checks against Australian water utilities, and overseas electricity and gas networks, also indicated that the AER's equity beta for the RBP was reasonable.

7.3.3.2 *Rate of Return Guideline*

In its rate of Return Guideline, the AER proposed estimation of a range for the equity beta, and selection of a point estimate from within that range.

The AER advised that it would obtain an estimate of beta from empirical analysis using data from a set of Australian energy utility firms which were reasonably comparable to the benchmark efficient entity of Rule 87(3).

The AER then proposed to use other information sources to inform the selection of a point estimate from within the empirical range of equity beta estimates. This additional information included:

- empirical estimates of betas for overseas energy networks; and
- the theoretical principles underpinning the Black CAPM.

The AER's range for equity beta estimates was subsequently established by reference to updated econometric analysis by Professor Henry in April 2014.[43] Professor Henry advised that, from his consideration of a number of estimation methods, and ranges of data for individual firms and portfolios of those firms, a point estimate for beta could be expected to lie in the range 0.3 to 0.8. The average of the ordinary least squares estimates of beta which he had obtained was 0.5223, and the median estimate was 0.3285.[44]

[43] Olan T. Henry, *Estimating β: An update*, April 2014.

[44] Olan T. Henry, *Estimating β: An update*, April 2014, page 63.

Professor Henry's April 2014 econometric analysis used samples for varying periods between 29 May 1992 and 28 June 2013.

The analysis included tests of parameter stability, from which Professor Henry concluded that there was no convincing evidence of instability.[45]

The AER examined, in addition to the results from Professor Henry's 2014 econometric analysis, the estimates of beta which had been made by Professor Henry for the 2009 review of WACC parameters, estimates made by the Western Australian Economic Regulation Authority (ERA), and estimates made by consultant SFG. All of this work, the AER concluded, supported an estimate of beta in the range 0.4 to 0.7.[46]

Beta estimates for overseas energy networks, the AER advised, supported a point estimate at the upper end of the range 0.4 to 0.7.[47] The difficulties of comparing entities operating in different financial market conditions and under different regulatory regimes precluded a more precise conclusion. The theoretical principles underpinning the Black CAPM similarly, and as imprecisely, pointed to an estimate at the upper end of the range.[48]

This led the AER to propose, in its Rate of Return Guideline, a point estimate of 0.7 for beta.

7.3.3.3 *Current evidence supports an estimate of beta higher than 0.7*

In June 2016, in the context of a Final Decision on proposed revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, the ERA updated its estimation of beta using data for the five years to 31 May 2016. The ERA found that, using returns data for portfolios of the Australian energy utilities used for beta estimation, a 95 per cent confidence interval for

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[45] Olan T. Henry, *Estimating β: An update*, April 2014, page 62.

[46] See Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, section 6.2.3.

[47] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 86.

[48] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 86.

beta was 0.479 to 0.870. The ERA concluded that the mean beta, 0.7, obtained as an average across the estimates for equally weighted and value weighted portfolios, made using the ordinary least squares, least absolute deviation, MM and Theil-Sen estimators, was an appropriate point estimate for use in the SL CAPM.[49]

The ERA's process of estimation clearly indicates an increase in beta since its own earlier (2013) work, and since Professor Henry's updated (2014) analysis for the AER. The ERA noted:

Across the four firms β has increased on average from 0.368 to 0.578 from 2013 to 2016 across all estimators (OLS, LAD, MM, T-S). Hence, elasticity in the response of individual asset returns to market returns has increased within the gas infrastructure sector during a period when mean market returns have decreased, consistent with the findings of CEG.[50]

Consultant CEG had reported, in work undertaken for Dampier to Bunbury Natural Gas Pipeline owner and operator DBP, that structural break tests which it had carried out using betas estimated from recent data showed multiple structural breaks. When the number of breaks was restricted to one, and betas were estimated using rolling three year windows, CEG found the most significant structural break occurred late in November or early in December 2014. When betas were estimated using rolling five year windows, CEG found that the structural break occurred in September 2013.[51]

The findings by CEG, and the ERA's subsequent acknowledgement of an increase in beta, should not be surprising. The time variation of betas, for Australian equities and for stocks issued in a number of other markets, is well established statistically, although whether the reasons for the variations lie in

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[49] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016-2020*, Appendix 4, Rate of Return, paragraph 474.

[50] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016-2020*, Appendix 4, Rate of Return, paragraph 935.

[51] CEG, *Estimating beta to be used in the Sharpe-Lintner CAPM*, February 2016, paragraph 120. The CEG report is Appendix F to DBP's submission 56 to the ERA dated 24 February 2016.

microeconomic factors or in macroeconomic factors, or in both, is not entirely clear.[52]

The ERA's beta estimate of 0.7 was obtained without any consideration being given to either beta estimates for overseas energy networks, or to the theoretical principles underpinning the Black CAPM. Consideration of these factors, as the AER proposes, may lead to a higher estimate for beta.

7.3.3.4 *APTPPL's estimate of beta*

In 2012, the evidence available to the AER, from its advisor, Professor Henry, indicated a point estimate for beta of between 0.4 and 0.7. The AER concluded that an estimate just above this range was justified:

- in recognition of the level of imprecision around beta estimation; and
- taking into account the desirability of stability in regulatory decision making over time.

By April 2014, the AER had the evidence of a number of studies in which beta had been estimated, including Professor Henry's update of his earlier work. These studies continued to show a range of 0.4 to 0.7. The AER may have, by then, consulted widely and prepared the Rate of Return Guideline, but the level of imprecision around beta estimation had not changed.

There was, by April 2014, a requirement for a rate of return which satisfied the allowed rate of return objective of Rule 87(3), and this may have changed, for the AER, the desirability of stability in regulatory decision making over time. Even so, the national gas objective, which had been in the NGL since

[52] See Robert D. Brooks, Robert W. Faff and Thomas Josev (1997), "Beta stability and monthly seasonal effects: evidence from the Australian capital market", Applied Economic Letters, 4, pages 563-566. More recently, Andersen, Bollerslev, Diebold and Wu have advised:

The preliminary results reported here indicate that equity market betas do indeed vary with macroeconomic indicators such as industrial production growth, and that the macroeconomic effects on expected returns are large enough to be economically important.

Torben G. Andersen, Tim Bollerslev, Francis X. Diebold and Jin Wu (2006), in "A Framework for Exploring the Macroeconomic Determinants of Systematic Risk", American Economic Association Papers and Proceedings, 95(2), pages 398-404.

2007, continued to shape regulatory decision making more broadly. If, in 2012, an access arrangement incorporating a reference tariff which had been calculated using a beta estimate of 0.8 achieved the broader requirements of the national gas objective, then, other things being equal, an access arrangement incorporating a reference tariff calculated using a beta estimate of 0.8 should continue to achieve the broader requirements of that objective. That will be the case, irrespective of the fact that the AER has made and published the guidelines required by Rule 87(13).

APTPPL therefore proposes to retain an estimate of 0.8 for beta for application of the SL CAPM in estimating the return on equity for the RBP.

However, in view of the recent and substantial variation in betas, observed by both the ERA and CEG, APTPPL will obtain updated estimates at the time of the AER's Draft Decision on the proposed revisions to the RBP Access Arrangement. APTPPL will, at that time, reassess the estimate of beta to be used in estimating the return on equity for the proposed revisions to the RBP Access Arrangement, and will submit an updated estimate in its response to the Draft Decision.[53] If beta is changing, an updated estimate is essential to making an estimate of the return on equity which has been made having regard to prevailing conditions in the market for equity funds. A beta estimate updated at the time of the Draft Decision will be essential to estimating a rate of return on equity which contributes to the achievement of a rate of return commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in the provision of reference services.

7.3.4 *Market risk premium*

In the Rate of Return Guideline, the AER proposed that the return on equity be estimated, using the SL CAPM, by adding to the risk free rate the product of the equity beta and the MRP. The MRP was unobservable, and was to be estimated. A range for the estimate of the MRP was to be established, and a

[53] APTPPL will consider, given its updated estimates, whether beta estimates for overseas energy networks, or the theoretical principles underpinning the Black CAPM, lead to a higher value for beta return on equity estimation for the proposed revisions to the RBP Access Arrangement.

point estimate selected from within that range. MRP estimation would, the AER proposed, have regard to dividend growth model estimates, survey evidence and conditioning variables, but the base for the estimate was to be historical excess returns.

At the time of this submission, the AER's most recent estimations of the return on equity included the estimate made for its May 2016 Final Decision on proposed revisions to the Access Arrangement for the Amadeus Gas Pipeline. In that decision, the AER selected 6.5% as a point estimate for the MRP, reasoning that:

- historical excess returns indicated a MRP of approximately 5.5 to 6.0 per cent from a range of 4.8 per cent to 6.0 per cent;
- dividend growth model estimates indicated a MRP estimate above this baseline with a range of 7.48 to 8.74 per cent;
- the AER's dividend growth model was theoretically sound, but its implementation raised a number of practical issues which led to the view that recent increases in estimates of the MRP made using the model did not necessarily reflect an increase in the 'true' expected ten-year forward looking MRP;
- dividend growth model estimates were not reliable on their own, but they nevertheless provided some support for a point estimate above the range from historical returns;
- survey evidence supported a MRP around 6.0 to 6.5 per cent;
- stakeholder submissions (excluding submissions by service providers) generally supported a MRP at or below the 6.5 per cent; and
- a departure from the Rate of Return Guideline on the basis of the information and material before the regulator was not justified and would not contribute to achievement of the allowed rate of return objective of rule 87(3), or to achievement of the National Gas Objective.[54]

[54] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2019, Attachment 3 – Rate of Return*, pages 3-55 – 3-57.

Although the AER considered the forward looking estimates of the MRP obtained using the dividend growth model, its estimate of 6.5% was anchored by historical excess returns. Anchoring the estimate in this way produces an MRP which varies only slowly over time as historical returns and the risk free rate vary. This would not be a problem if the MRP were relatively stable, but it is not. The AER advised, in the Explanatory Statement accompanying the Rate of Return Guideline, that the MRP varied over time:

> *Evidence suggests the MRP may vary over time. In their advice to the AER, Professor Lally and Professor Mackenzie and Associate Professor Partington have expressed the view that the MRP likely varies over time. They also suggest it would be better to use a wide range of models and information to estimate the MRP.*[55]

If the MRP varies over time, a method of estimation which anchors the estimate on the average of historical excess returns is unlikely to lead to a forward looking estimate of the premium.

Furthermore, Rule 87(7) requires that, when estimating the return on equity, regard be had to prevailing conditions in the market for equity funds. The AER may, as it has advised, have had regard to prevailing market conditions through its use of the dividend growth model and conditioning variables to inform its estimate of the MRP.[56] However, an estimate which is anchored on an average of historical excess returns does not give much weight to prevailing conditions.

An estimate of 6.5%, which is anchored on historical excess returns, and which is not forward looking, would not be an appropriate estimate for application of the SL CAPM, and could not lead to an estimate of the return on equity which contributed to a rate of return commensurate with the efficient financing costs of the benchmark efficient entity of Rule 87(3).

These were problems recognised by the ERA in its recent final decisions on the proposed revisions of the access arrangements of the three Western Australian providers of regulated pipeline services.

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[55] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 91.

[56] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2019, Attachment 3 – Rate of Return*, page 3-83.

7.3.4.1 ERA estimation of the MRP

Reliance on historical excess returns could not, the ERA reasoned, provide the forward looking estimate of the MRP required for application of the SL CAPM. In the absence of an adequate theory of expectations formation, the only model available for making such a forward looking estimate was the dividend growth model. The ERA therefore inverted the AER's approach to MRP estimation, using the estimates from a set of dividend growth models, and using the average of historical excess returns as a cross check.

The set of dividend growth models used by the ERA included its own model, and the model developed by the AER. From these models, the ERA established a range for the upper limit of possible values for the MRP. This range was 7.6% to 8.8%.[57]

The average of historical excess returns is neither forward looking nor strongly reflective of prevailing financial market conditions. Nor, as the ERA advises, is the time series of excess returns stationary. However, the ERA found the market return on equity series to be stationary, with the implication that an average of a long span of data could provide a cross check on any estimate of the market return on equity made using the dividend growth model.[58]

Using the data compiled by Brailsford, Handley and Maheswaran, and taking into account (but not fully adjusting for) NERA's suggested corrections to the early part of the series for equity returns, the ERA found that the nominal average return on the market was 10.3%.[59] If, as the ERA determined, the risk free rate was 1.82%, this suggested a MRP of around 8.48%.[60]

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[57] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1031.

[58] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1011

[59] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1010.

[60] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1012.

The average of historical excess returns themselves, the ERA contended, provided, at best, a lower bound on the range of the estimate of the MRP. The value or values of this lower bound would depend on the way in which the average was calculated, either as an arithmetic mean or as a geometric mean. In its calculations, the ERA gave weight to both means, finding that a reasonable lower bound on the estimate of the MRP was 5.4%.[61]

The ERA concluded that:

- the range for the MRP implied by historical excess returns was 5.4% to 8.5%; and
- the range for the MRP implied by recent estimates made using dividend growth models was 7.6% to 8.8%.[62]

A point estimate, for use in the SL CAPM, must be established, the ERA contended, by reference to these ranges. Like the AER, the ERA examined a number of forward looking indicators – "conditioning variables" – to establish its point estimate. The indicators were:

- the dividend yield on the All Ordinaries which, the ERA found, supported an estimate for the forward looking MRP that was above the mid-point of the range implied by historical excess returns;[63]
- interest rate swap and bond default spreads, which were relatively high, indicating slightly elevated risk premiums;[64]
- the ASX 200 volatility index, which indicated an MRP below the mid-point of the range implied by historical excess returns;[65] and

[61] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1038.

[62] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1065.

[63] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1049.

[64] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1055.

[65] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1059.

- the (qualitative) assessment of the Reserve Bank of Australia, in its May 2016 *Statement on Monetary Policy*, that there was uncertainty concerning future growth in the Australian economy, which the ERA saws as driving a somewhat higher MRP at the present time.[66]

The conditioning variables indicated, to the ERA, a forward looking rate of return which was higher than the mid-point of range for the MRP implied by historical excess returns.

The range of estimates of the MRP from dividend growth models was 7.6% to 8.8% but, as was recognised by the ERA, these models tended to overestimate returns.

The ERA concluded that an estimate of the MRP of 7.4% would reflect market expectations at the end of May 2016.[67] It was an appropriate estimate of the MRP for estimating the rate of return on equity using the SL CAPM.

APTPPL notes that, in its estimation of rates of return, the ERA assumed:

- the appropriate proxy for the risk free rate was the yield on Australian Government bonds with a term to maturity of five years; and
- equity returns were grossed up to account for the value of imputation credits (after 1987) using a value of theta which was consistent with the Western Australian regulator's estimate of gamma of 0.4.

APTPPL does not agree with the ERA's view that bonds with a term to maturity of five years are an appropriate proxy for the risk free rate. As noted above, APTPPL has used Australian Government bond with a term to maturity of 10 years as the proxy for the risk free asset. This is consistent with economic theory, with financial market practice, and with the AER's Rate of Return Guideline.

Neither does APTPPL agree with the ERA's assumption that gamma is 0.4. As APTPPL discusses below, the best estimate of gamma currently available is 0.25.

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[66] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1062.

[67] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, paragraph 1070.

The ERA's use of Australian Government bonds with term to maturity of five years as the proxy for the risk free asset is likely to overstate the estimate of the MRP (relative to an estimate calculated using yields on bonds with a maturity of 10 years as the proxy for the risk free asset). However, this overstatement does not significantly influence the result. The uncertainty in the inputs to the dividend growth model is relatively large.

The ERA's estimate of the MRP is more closely grounded in prevailing conditions in equity market than the estimate made by the AER, and better reflects the requirement for a forward looking estimate. Whether it should then be used in the SL CAPM for estimating the return on equity is less clear. Beyond its comment that, if the risk free rate were 1.82%, an estimated return on the market of 10.3% suggested a MRP of around 8.48%, the ERA does not explain how it has applied the risk free rate in obtaining its estimate of 7.4% for the MRP.

7.3.4.2 *MRP in the SL CAPM requires the current risk free rate*

The SL CAPM is a model of equilibrium asset returns derived from a simple, static mean-variance model of portfolio choice.[68]

In this model of portfolio choice, an investor chooses, at a point in time (time 0), to consume a part of his wealth and to invest the remainder in a portfolio of financial assets. By investing, the investor transfers a part of his wealth to a later time (time 1) to finance future consumption.

In choosing assets to form a portfolio to transfer wealth from time 0 to time 1, the investor can choose, at time 0, to invest in a finite number, N, of risky financial assets, each of which provides the investor with a payoff, at time 1, from the cash flows of the entity which issued the asset. Different circumstances over which the investor has no control (different contingent states) are possible during the period of the investment (between time 0 and time 1), and lead to different possible payoffs on each risky asset. The payoffs, then, are not known to the investor at time 0. They are random variables at that time. Provided each asset has a non-zero price at time 0,

[68] For a rigorous derivation of the SL CAPM, see Chi-fu Huang and Robert H Litzenberger (1988), *Foundations for Financial Economics*, New York: Elsevier, chapters 3 and 4.

the rates of return which the investor can earn on the assets are also random variables.

The investor can also choose, at time 0, to invest in a risk free asset. The risk free asset provides the investor with the same – known – return in all of the contingent states between time 0 and time 1. The variance of the return on the risk free asset is zero.

The investor choosing assets to form a portfolio is assumed to:

- prefer a portfolio with a higher expected return to a portfolio with lower expected return, where both portfolios have the same variance of portfolio returns; and
- prefer a portfolio with lower variance of returns to a portfolio with higher variance of returns, where both portfolios have the same expected return.

An investor with these preferences will choose a mean-variance efficient portfolio, a portfolio which has minimum variance of returns for a given expected portfolio return, subject to the investment in the portfolio not exceeding that part of his wealth which the investor chooses to invest at time 0.

In the solution to this minimisation problem, the expected return on each risky asset *j* in the chosen portfolio is:

$$E(r_j) = r_f + \frac{cov(r_j, r_e)}{var(r_e)}\left[E(r_e) - r_f\right] \qquad (1)$$

where r_e is the return on a mean-variance efficient portfolio, and $cov(r_j, r_e)$ is the covariance of the returns on asset *j* and the mean-variance efficient portfolio. $var(r_e)$ is the variance of returns on the mean-variance efficient portfolio.

Equation (1) describes the rate of return which an individual investor might expect to earn at time 1 on each risky asset *j* in a portfolio formed, at time 0, from a risk free asset and from *N* risky assets which are available at that time. The expected return on risky asset *j* is equal to the rate of return on the risk free asset available to the investor at time 0, plus a premium for risk which depends on the covariance of the return on asset *j* with the return on some mean-variance efficient portfolio of the risky assets.

Figure 6: Portfolio frontier, efficient frontier and capital market line

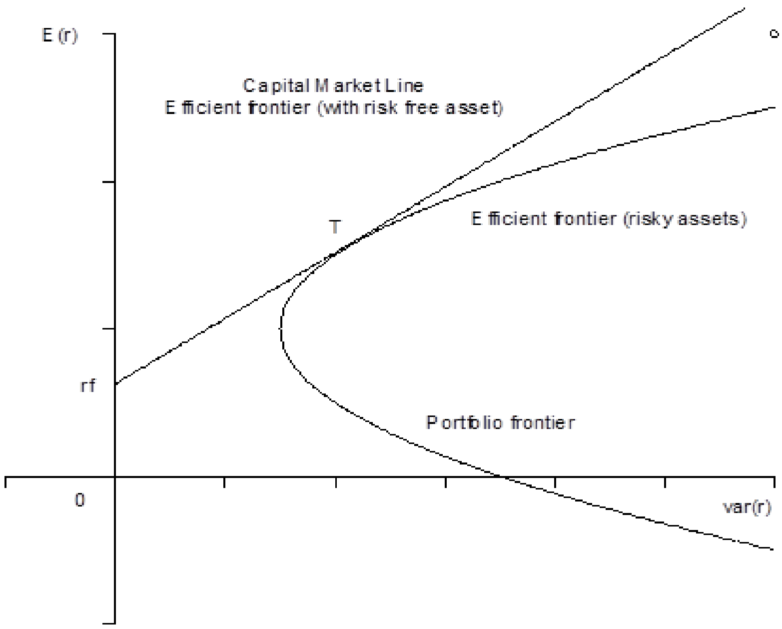

Figure 6 shows the set of mean-variance efficient portfolios which might be constructed from the *N* risky assets available to the investor. This set of mean-variance efficient portfolios is the portfolio frontier. If the investor's preferences are increasing and strictly concave, the investor will choose only weights for a portfolio of risky assets which is represented by a point on that part of the portfolio frontier above and to the right of the point of minimum portfolio variance. This part of the portfolio frontier is sometimes referred to as the efficient frontier.

When a risk free asset with return r_f is available to an investor choosing a portfolio at time 0, the efficient frontier is the straight line r_fT shown in Figure 6. The line r_fT – the capital market line – is tangential, at point T, to the efficient frontier for risky assets.

Turn, now, from the individual investor to all investors in the market for financial assets. All investors are assumed to hold, at time 0, the same expectations about the returns on the risky assets at time 1. Therefore, they all hold the same portfolio of risky assets, which is the portfolio represented by the point of tangency T in Figure 6.

Let W_k be the amount of wealth individual *k* invests in the portfolio of risky assets corresponding to the point of tangency T, and let X_{jk} be the number of units (shares) of risky asset *j* held by that individual. Since all investors hold the same portfolio of risky assets,

$$w_j^T = \frac{p_j X_{jk}}{W_k}, \qquad k = 1, 2, \ldots, K$$

where w_j^T is the fraction of wealth invested in asset *j* in the portfolio corresponding to point of tangency T, p_j is the market price of asset *j*, and *K* is the number of investors in the market for financial assets.

Summing over all *K* investors:

$$w_j^T = \frac{p_j \sum_{k=1}^{K} X_{jk}}{\sum_{k=1}^{K} W_k}$$

The numerator in this fraction is the total market value of asset *j*, and the denominator is the total value of all risky assets. w_j^T is, then, the fraction of wealth invested in risky assets which is invested in asset *j*.

The portfolio corresponding to point of tangency T has weights w_j^T, for risky assets *j = 1, 2, . . . , N*, which are the ratios of the total market values of each of the assets to the total value of all risky assets. The portfolio corresponding to point of tangency T is, then, the market portfolio. Consistent with this terminology, the expected return on the market portfolio is $E(r_m)$, and the variance of return on the market portfolio is $var(r_m)$.

The market portfolio lies on the efficient frontier: it is a mean-variance efficient portfolio. It will be observable if aggregate holdings of risky financial assets can be observed. The market portfolio can replace the undefined mean-variance efficient portfolio in equation (1) above. The return on risky asset *j* is, then:

$$E(r_j) = r_f + \frac{cov(r_j, r_m)}{var(r_m)}\left[E(r_m) - r_f\right] = r_f + \beta_j[E(r_m) - r_f]$$

This is the SL CAPM.

The SL CAPM is the outworking of individual investors choosing, at a point in time, portfolios of the *N* risky assets and the risk free asset which are available at that time.

In the SL CAPM, there is no single construct [$E(r_m) - r_f$]. There are, clearly and distinctly, the known return, r_f, on the risk free asset available to investors, and the expected return, $E(r_m)$, on the market portfolio of the risky assets available to those investors.

The term [$E(r_m) - r_f$] as it appears in the SL CAPM is not a composite. It is not a single parameter for which an estimate is required separate from the estimates of the risk free rate and beta.

The term [$E(r_m) - r_f$] must be treated as comprising two components, the risk free rate and the expected return on the market, when applying the model. Estimates must be made, at the time the SL CAPM is applied, of:

- the rate of return on the risk free asset assumed to be available to investors at that time; and
- the return those investors expect, at that time, to earn on the market portfolio.

The use of an average of historical excess returns to estimate [$E(r_m) - r_f$] as a single construct for the purpose of applying the SL CAPM is conceptually incorrect.

A long term average of past returns on the market portfolio may be used as an estimate of the expected return on the market, $E(r_m)$, but the use of that average involves the making of a specific assumption about the way in which expectations are formed. This assumption – indeed, any assumption which might be made about expectations formation – lies beyond the set of assumptions underpinning the SL CAPM itself. The absence of an explicit hypothesis about how expectations are formed about a critical element of the model (the return on the market portfolio) is a significant limitation of the SL CAPM.

Moreover, the use of a long term average of historical excess returns to estimate [$E(r_m) - r_f$] has the effect of replacing the risk free rate of return at the time of portfolio choice with a long term average of risk free rates of returns. But a long term average of risk free rates has no role in the SL CAPM, and no role in the application of the model. In the derivation of the SL CAPM, there is no consideration of how expectations are formed about an uncertain future risk free rate of return. There does not need to be. The risk free rate is known with certainty at the time of portfolio choice: it is the known rate of return on the risk free asset which is available to investors at that time.

None of this means that the MRP, interpreted as a long term average of differences between the return on the market portfolio and the risk free rate, is not relevant in other contexts. Considered independently of the SL CAPM, the MRP has been, and continues to be, of great interest to investors and to financial economists. Whether the MRP is a premium for bearing non-diversifiable risk or a liquidity premium, or whether it arises from borrowing constraints or taxes and other regulatory arrangements remain open questions.[69]

Since the term $[E(r_m) – r_f]$ as it appears in the SL CAPM is not a composite, and must be estimated using the rate of return on the risk free asset assumed to be available to investors at the time the model is applied, and from the return those investors expect to earn on the market portfolio at that time, survey and other evidence which supposedly directly informs estimates of the MRP, is irrelevant. It has no role in the application of the SL CAPM.

The dividend growth model potentially has a role in the application of the SL CAPM. That role is in the estimation of the expected return on the market at the time the model is applied.

There is, in the Rate of Return Guideline, some recognition of the MRP being the difference between the expected return on the market portfolio and the rate of return on the risk free asset at the time the model is applied, but that recognition is limited to what the AER refers to as the "Wright approach".

The AER describes the Wright approach as an alternative – "non-standard" – implementation of the SL CAPM in which the market portfolio and the risk free rate are estimated as separate components of the MRP. The Rate of Return Guideline explains:

> *Effectively, under the Wright approach the estimation of the MRP is replaced by the estimation of the return on the market. If the return on the market portfolio is assumed to be relatively constant*

[69] See Rajnish Mehra and Edward C. Prescott (2003), "The equity premium in retrospect", in George M. Constantinides, Milton Harris and René Stulz (eds.), *Handbook of the Economics of Finance*, Volume 1, Part B, Financial Markets and Asset Prices, New York: Elsevier, pages 889-938.

> *(and this is a strong assumption), estimates of the expected return on equity for the benchmark efficient entity, therefore, will only move marginally with variations in the risk free rate.*[70]
>
> . . .
>
> *The Wright approach, however, has a number of limitations. In particular, it assumes that the relationship between the risk free rate and the MRP is perfectly negatively correlated, and the return on equity is relatively stable over time.*[71]
>
> . . .
>
> *Consistent with our final decision for the Victorian gas service providers, we consider there is no consensus in the academic literature on the direction, magnitude or stability of the relationship between the risk free rate and the MRP. Instead, there is evidence to support both a positive and negative relationship. Given these uncertainties – in particular, that the direction of any relationship may be variable and unstable – we consider it more reasonable to assume that no consistent relationship exists between the MRP and risk free rate.*[72]

In applying the SL CAPM, APTPPL makes no assumptions about whether the real return on the market is constant, or about the correlation between the risk free rate and the MRP. APTPPL does not apply the Wright approach.

APTPPL has applied the SL CAPM in a way which is consistent with the form of the model and with the economic principles from which it is derived. APTPPL has made estimates, at the time of model application, of:

- the rate of return on the risk free asset assumed to be available to investors at that time; and

[70] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 24.

[71] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 25.

[72] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 26.

- the return those investors expect, at that time, to earn on the market portfolio.

APTPPL has then used the difference between its estimate of the return on the market portfolio and its estimate of the risk free rate as the estimate of the term [$E(r_m) - r_f$] in the model. This, and not an estimate of [$E(r_m) - r_f$] taken as a single parameter, is the correct way in which to apply the SL CAPM. Estimation of [$E(r_m) - r_f$] as a single parameter, relying (although not exclusively) on an average or averages of historical excess returns, is conceptually incorrect, and therefore leads to an estimate of the return on equity which cannot, except by chance, be an estimate which contributes to the achievement of the allowed rate of return objective.

Moreover, given prevailing conditions in financial markets, with the yields on the Australian Government securities which proxy for the risk free rate close to their historic lows, use of a long term average of the risk free rate proxy in place of the current value of that proxy – imparts a downward bias to estimates of equity returns obtained by applying the SL CAPM.[73]

7.3.4.3 *APTPPL's estimate of the MRP*

In Table 3-26 of Attachment 3 to its May 2016 Final Decision on proposed revisions to the Access Arrangement for the Amadeus Gas Pipeline, the AER listed average historical returns on the market portfolio (in nominal terms) for a number of different periods. These long term averages of market return ranged from 10.0% to 12.7%.

APTPPL has taken the lower end of the AER's range, 10.0%, as a reasonable – indeed, conservative - value for the average return on the market portfolio. Acknowledging differences in the lengths of series, and in calculation methods, this is supported by the ERA's nominal average return on the market of 10.3% noted in section 7.3.4.1 above.

[73] In its November 2015 Statement on Monetary Policy (at page 47), the Reserve Bank of Australia advised that yields on government bonds remain close to historic lows. Since November 2015, those yields have fallen.

Section 7.3.4.1 also noted that the ERA found that the market return on equity series was stationary, with the implication that a long span of data could provide an estimate of the expected return on the market portfolio.

APTPPL has, therefore, used 10.0% as an estimate of the forward looking expected return on the market portfolio.

APTPPL's estimate of the risk free rate of return was, as noted in section 7.3.2, 1.94%.

The difference between the expected return on the market and the current risk free rate – the MRP required for the conceptually correct application of the SL CAPM – is, therefore, 8.06%.

7.3.5 *Estimating the return on equity*

Using the estimates discussed in the preceding paragraphs (r_f = 1.94%, β = 0.8, and MRP = 8.06%), the foundation model – the SL CAPM – delivers an estimate of the return on equity of 8.39%.

7.3.6 *Evaluation of APTPPL's estimate of the return on equity*

APTPPL considers that an estimate of the return on equity of 8.39% is the best estimate in the circumstances. It is an estimate made using the AER's foundation model, and having regard to prevailing conditions in the market for equity funds. It is an estimate which can contribute to achievement of the allowed rate of return objective of Rule 87(3).

APTPPL has derived its estimate using the SL CAPM, which is a model for estimating equity returns long used by financial market practitioners and regulators. After examining the alternatives, the AER found the SL CAPM to be an appropriate model for estimating the return on equity required by Rule 87 of the NGR, and adopted that model as its foundation model.

Two of the three parameters which must be estimated when applying the SL CAPM are the risk free rate of return and the equity beta. There are well established and accepted methods of estimating the risk free rate and beta. APTPPL has used the method of estimating the risk free rate of return proposed in the Rate of Return Guideline. When estimating beta, APTPPL has drawn on the estimates made for, and adopted by the AER, and has also had regard to the more recent estimates made by the ERA. These more recent estimates indicate that beta may be changing over time. If, as Rule 87(7) requires, the return on equity is to be estimated having regard to prevailing conditions in equity markets, beta should be re-estimated closer to the time of the AER's final decision. APTPPL will provide an updated estimate of beta, and an updated estimate of the return on equity, when responding to the AER's draft decision on the proposed revisions to the RBP Access Arrangement.

APTPPL has explained above that the AER's approach to estimation of the third parameter of the SL CAPM – the MRP – is based on a view of the model which is conceptually incorrect. The MRP of the SL CAPM is the difference between the expected return on the market portfolio and the risk free rate at the time the model is applied.

APTPPL notes that this is not the Wright approach, and that it has not applied the Wright approach to the SL CAPM.

The result is a higher MRP and, in consequence, a higher return on equity, than would have been obtained by the AER and by others who similarly – and incorrectly – interpret the SL CAPM. To the extent that the details are discernible from the ERA's decisions, APTPPL's estimation of the MRP seems to be consistent with the approach adopted by the ERA.

7.4 Estimating the return on debt

The benchmark efficient entity of Rule 87(3) would, the AER advised in the Explanatory Statement which accompanied the Rate of Return Guideline, issue debt with a term to maturity of 10 years. To mitigate its refinancing risk the benchmark efficient entity would hold a portfolio of debt with staggered maturities. The Rate of Return Guideline therefore proposed that the return on debt be estimated:

- for debt with a benchmark term to maturity of 10 years;
- using an on-the-day approach (return on debt equal to the sum of a current base rate and current debt risk premium) in the first regulatory year of the access arrangement period; and

- transitioning the rate obtained using the on-the-day approach into a trailing average over 10 years by updating one tenth of the return on debt in each subsequent year to accord with prevailing financial market conditions.

The Explanatory Statement set out the rationale for a transition to trailing average estimation of the return of debt rather than its immediate implementation. Under the on-the-day approach to return on debt estimation which had been previously applied, the benchmark efficient entity would have:

- borrowed long term (10 years) and staggered its borrowings so that only a proportion (10%) of the debt matured each year and needed to be refinanced;
- borrowed using floating rate debt (or using fixed rate debt converted into floating rate debt using fixed-to-floating interest rate swaps); and
- entered into floating-to-fixed interest rate swaps, during the averaging period at the commencement of each access arrangement period, for the risk free rate component of the return on debt, for the duration of the access arrangement period.

As a result, the benchmark efficient entity would have held a portfolio of floating rate debt at the time a new approach to estimation of the return on debt was to be implemented. This portfolio would need to be "unwound" as part of any change from an on-the-day to a trailing average approach to estimation of the return on debt. This, the AER proposed, would be effected by transition to the trailing average over a period of 10 years.

The hedging arrangements through which the benchmark efficient entity's portfolio of floating rate debt was created were in respect of the risk free rate components of its initial long term borrowings. There was no market in which the debt risk premiums could be hedged.

Transition to a trailing average approach was, in the AER's view, necessary to allow the benchmark efficient entity for which the return on debt is estimated to unwind the hedging arrangements it had entered into under the previously used on-the-day approach. Only a regulated entity would have had to contend with on-the-day estimation of the return on debt, and would have hedged in response to that on-the-day estimation of the return on debt. The benchmark efficient entity was, therefore, a regulated entity.

7.4.1 *Tribunal review of the AER's approach to estimation of the return on debt*

On 26 February 2016, the Australian Competition Tribunal (Tribunal) handed down decisions on applications for merits reviews by Networks NSW, ActewAGL and Jemena Gas Networks (NSW) Ltd (Jemena). The Tribunal decided to set aside the AER's decisions for each of the businesses, and to remit various matters to the AER for reconsideration, including in relation to the return on debt.

The Tribunal's key conclusions on the estimation of the return on debt in the AER's decisions for Networks NSW, ActewAGL and Jemena were:

- the benchmark efficient entity is an unregulated entity, and the AER therefore erred in treating it as regulated for the purposes of its decision on the form of transition to the trailing average method;[74]
- the AER erred in deciding that there must be a single, standard benchmark efficient entity, and that there must be a single, standard form of transition appropriate for all service providers;[75]
- in the light of the AER's errors in interpretation of the rate of return objective and in characterisation of the benchmark efficient entity, the AER's approach to transitioning to the trailing average must be reconsidered.

The Tribunal also provided some direction as to the proper implementation and application of clause 6.5.2(k)(4) of the National Electricity Rules, which is equivalent to Rule 87(11)(d) of the NGR.[76] The Tribunal stated that the application of this rule involves:

- starting with the efficient financing costs of an unregulated benchmark efficient entity;

[74] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [907], [914].

[75] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [916].

[76] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [933].

- where the AER is intending to change the method for estimating the return on debt, considering whether there would be any impact on the benchmark efficient entity as a result of the changed method; and
- taking into account any such impacts in deciding on the transition to the new method.

In relation to the first step, the Tribunal noted that as the financing costs structure of Networks NSW was readily applied to the trailing average method, the relevant inquiry would start with whether the actual financing costs were efficient as at the commencement of the new regulatory period, and only if the actual structure was not efficient would that of the benchmark efficient entity be applied prospectively.[77]

The Tribunal did not identify what it considered to be the correct form of transition for each business. Rather, the Tribunal directed the AER to remake its decision on the transition method in accordance with the principles and guidance set out in the Tribunal's reasons.

7.4.2 *APTPPL's estimation of the return on debt*

For the purpose of estimating the return on debt, APTPPL has assumed that the benchmark efficient entity of Rule 87(3) is an unregulated entity which raises debt with a term to maturity of 10 years. Debt raising is staggered so that only a part of the total debt must be refinanced each year, thereby reducing refinancing risk. The efficient financing practice of an unregulated benchmark efficient entity facing a similar degree of risk to RBP service provider APTPPL is, then, to have a staggered portfolio of rate debt with 10% of its debt is refinanced annually.

Since the benchmark efficient entity is unregulated, it may or may not benefit from hedging interest rate risk. In the case of an unregulated entity there is, of course, no regulatory allowance for the return on debt against which the entity might hedge the risk of adverse movements in the interest rates on the debt it has, in fact, raised. Moreover, as Partington and Satchell have noted: "Hedging is a choice, but not necessarily the best choice, so

[77] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [934].

not all firms will choose to fully hedge and possibly some may choose not to hedge at all".[78] In the case of an unregulated entity, whether there are benefits from hedging will depend on the specific circumstances of the entity. The benchmark efficient entity is not, therefore, assumed to hedge, and there are no hedges to be unwound. If the return on debt of the benchmark efficient entity is to be estimated using a trailing average, then trailing average estimation can be implemented immediately. There is no need for a transition.

APTPPL has, therefore, estimated for the benchmark efficient entity (an entity with a credit rating in the BBB range) an equally weighted average cost of debt for fixed rate debt raised in each of the last 10 years (including the current year). For this, APTPPL has used the yields on the BBB rated debt of non-financial corporations, published by the Reserve Bank of Australia, extrapolated to maturities of 10 years. Consistent with other aspects of its determination of a proposed allowed rate of return, APTPPL has used the yield on debt in July of each year in estimating the return on debt for that year.

APTPPL's estimate of the return on debt of the benchmark efficient entity, made as a historical trailing average of yields over the last 10 years, is 7.26%. This is an estimate of the return on debt which reflects the efficient financing practice of the benchmark efficient entity as required by the allowed rate of return objective of Rule 87(3).

APTPPL itself did not raise any debt under the previous "on-the-day" approach to estimating the regulatory allowance for the return on debt and therefore, its financing cost structure can be readily applied to the trailing average approach.

APTPPL is a company within the APA Group of companies. All debt raising and portfolio management, including interest rate and foreign currency hedging, is undertaken by the Group Treasury department. As part of its financial risk management, the Treasury department staggers its raising of debt for the Group. As at 30 June 2016, 86.5% of interest obligations on on

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[78] Graham Partington and Stephen Satchell, *Report to the AER: Discussion of the Allowed Cost of Debt*, 5 May 2016, page 18.

gross borrowings was either hedged into or issued at fixed interest rates for varying periods extending out to 2035.[79]

Interest rate swaps are used to hedge the risk of rising interest rates. Only a relatively small proportion of APA Group revenue is affected by regulatory determinations and, in hedging interest rate risk, there is no alignment of hedging arrangements with regulatory allowances: APA Group does not hedge the base rate components in the debt which it has raised with the risk free rates in any of the determinations for entities within the Group which are subject to economic regulation. APA's practice is consistent with what would be expected of an unregulated benchmark efficient entity.

In the case of APTPPL, then, there is no relevant "impact" that would be suffered in moving to a trailing average method for estimating the return on debt, and so no adjustment is warranted under Rule 87(11)(d). Rather, the effect of moving to the trailing average method will simply be to better align the allowed rate of return with the efficient financing costs of a benchmark efficient entity facing a degree of risk similar to that faced by APTPPL.

The estimate of the return on debt required by Rule 87 is, in these circumstances, simply the historical trailing average of the costs of debt for the benchmark efficient entity. It is 7.26%.

7.5 Allowed rate of return for RBP Access Arrangement revisions proposal

APTPPL's estimates of the return on equity and the return on debt are, respectively, 8.39% and 7.26%. Use of each of these estimates in determining the allowed rate of return for the RBP contributes to achievement of the allowed rate of return objective for the reasons set out above.

APTPPL has calculated a nominal vanilla weighted average of its estimates of the return on equity and the return on debt, with the estimates weighted using the gearing of the benchmark efficient entity (0.6). That weighted average, 7.7%, is a rate of return commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the APTPPL in respect of its provision of the reference service using the RBP.

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[79] APA Group, *Annual Report For the financial year ended 30 June 2016*, page 30.

APTPPL therefore proposes an allowed rate of return of 7.7% for the revisions to the RBP Access Arrangement.

7.6 Implementation

Two issues which arise in the implementation of the allowed rate of return are addressed in this section of the submission. They are:

- annual updating of the return on debt; and
- the averaging period to be used when updating the return on debt estimate.

7.6.1 Annual updating

Rule 87(9)(b) permits the return on debt to be estimated using a method which results in that return, and the allowed rate of return, being different for different regulatory years in the access arrangement period.

APTPPL intends that the estimate of the return on debt be updated annually during the access arrangement period.

If the return on debt is updated annually, then the total revenue is to be changed through the automatic application of a formula that is specified in the decision on the proposed revisions to the RBP Access Arrangement.[80]

The annual updating of the return on debt will effect a variation of the reference tariff for the RBP in each year of the access arrangement period. A full access arrangement must include a mechanism for variation of the reference tariff over the course of the access arrangement period, and APTPPL has incorporated the variation of the reference tariff effected by annual updating of the return on debt into the reference tariff variation mechanism of the proposed revised RBP Access Arrangement.

[80] NGR, Rule 87(12).

7.6.2 *Averaging period*

If the return on debt is updated annually, data must be collected and an estimate of that return must be made close to the start of each regulatory year of the access arrangement period.

APTPPL proposes an averaging period of 20 trading days for the RBP. APTPPL will nominate specific averaging periods for the period July 2017 to December 2022 when responding to the AER's draft decision on the proposed revisions to the RBP Access Arrangement.

7.7 Value of imputation credits

The total revenue from which a revised reference tariff is to be determined is to include, as one of its building blocks, the estimated cost of corporate income tax (Rule 76).

Rule 87A(1) requires that the cost of corporate income tax be estimated for each year of an access arrangement period using the formula:

$ETC_t = ETI_t \times r_t \times (1 - \gamma)$

where ETC_t is the estimated cost of income tax in year t; ETI_t is an estimate of the taxable income for regulatory year t that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider; and r_t is the expected statutory income tax rate in year t.

Rule 87A(1) defines γ (gamma) as "the value of imputation credits".

The AER estimates gamma as the product of two parameters. These are:

- the distribution rate – the proportion of imputation credits generated that is distributed to investors; and
- the value, per dollar to investors, of imputation credits distributed (the utilisation rate, or theta).

The Rate of Return Guideline proposes a value of gamma of 0.5, which is the product of an estimate of 0.7 for the distribution rate, and an estimate of theta of 0.7.

7.7.1 *Estimation of gamma in the AER's recent decisions*

In its recent regulatory decisions, the AER has advised that there is a widely accepted approach to estimating the distribution rate.[81] However, there is no single accepted approach to estimating theta.

7.7.1.1 *AER estimation of the distribution rate*

The widely accepted approach to estimating the distribution rate uses statistics published by the Australian Taxation Office. The estimate made, and which continues to be made, using those statistics is 0.7. That estimate of the distribution rate has previously been regarded as an estimate arrived at on a reasonable basis, and as representing the best estimate possible in the circumstances. It was the estimate proposed in the Rate of Return Guideline.

Since the Rate of Return Guideline was made and published, the AER has re-examined estimation of the distribution rate. In a number of decisions, the AER has made reference to the views of:

- Associate Professor John Handley, that the estimate of the distribution rate should be made using only the credits generated and distributed by listed entities, resulting in a higher estimate of the distribution rate of 0.8; and
- Dr Martin Lally, who considers that the best estimate of the distribution rate is 0.84, calculated using data for the 20 largest ASX-listed companies.[82]

The AER has advised that, when estimating both the distribution rate and the value of distributed imputation credits, consideration must be given to whether the data used should be for all companies and their investors (all equity), or only for listed companies and their investors (only listed equity).

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[81] See, for example, Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-23.

[82] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, pages 4-31 – 4-32.

When the distribution rate was estimated on an only listed equity basis the result was an estimate of 0.75.[83]

7.7.1.2 *AER estimation of the utilisation rate (theta)*

The evidence relevant to the estimation of utilisation rate, the AER advises, includes:

- the proportion of Australian equity held by domestic investors (the 'equity ownership approach');
- the reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics'); and
- studies that seek to infer from market prices the value to investors of distributed imputation credits ('implied market value studies').[84]

Equity ownership approach

The AER assumes that the utilisation rate for eligible investors - the value, per dollar, of imputation credits distributed to those investors, is 1; the utilisation rate for investors who are ineligible to use the credits is 0. The AER therefore contends that the value-weighted proportion of domestic investors in the Australian equity market is a reasonable estimate of the utilisation rate.

This approach to estimation of the utilisation rate – the equity ownership approach – seems to be the approach on which the AER places most reliance.[85] It has led to a range of 0.38 to 0.55 for the estimate of the utilisation rate.[86]

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[83] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-31.

[84] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-24.

[85] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-27.

[86] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, Table 4-4.

Tax statistics

The AER advises that it has had regard to the evidence from tax statistics when considering estimates of the utilisation rate. Those statistics have indicated an estimate of 0.48.[87] However, the AER has concerns about limitations in the statistics themselves. The AER, therefore, places a degree of reliance on estimation of the utilisation rate using tax statistics that is less than that placed upon the equity ownership approach.[88]

Implied market value studies

Implied market value studies estimate the value of distributed imputation credits from market prices. Dividend drop off studies are a common type of implied market value study. In dividend drop off studies, the prices of securities with entitlements to dividends are compared with the prices without the dividend entitlements. Econometric techniques are then used to infer the value of the imputation credits attached to the dividends.[89]

These studies, the AER concludes, produce a wide range of estimates for the utilisation rate – between 0 and 1.[90]

Implied market value studies and, in particular, dividend drop off studies, are the AER contends, subject to limitations arising from the data used, from the econometric techniques employed, and from the need to interpret the results (since only the value of the combined package of dividends and imputation credits that can be observed).

The AER is therefore of the view that little reliance can be placed on the results of implied market value studies. The equity ownership approach and

[87] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, Table 4-3.

[88] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-35.

[89] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-37

[90] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, Table 4-4.

tax statistics provide more direct and simpler evidence; they, and not implied market value studies, should inform estimation of the utilisation rate.[91]

7.7.1.3 *Estimation of gamma*

A reasonable estimate of the range for gamma, the AER contends, is 0.3 to 0.5. From within this range, the AER has chosen an estimate of 0.4, observing that:

- its preferred equity ownership approach to estimation of the utilisation rate indicates a value of gamma between 0.28 and 0.47 when gamma is calculated using matched distribution and utilisation rates for all equity and for only listed equity, respectively;
- tax statistics, on which less reliance is placed, indicate a value of the utilisation rate of 0.48; the estimate of gamma obtained using this estimate of the utilisation rate and the all equity estimate of the distribution rate (0.7) is 0.34;
- the evidence from implied market value studies, evidence on which little reliance should be placed, suggests an estimate of gamma between 0 and 0.75, with the results of SFG's dividend drop off study suggesting a value in the range 0.26 to 0.30, which is at the bottom end of the equity ownership approach range of 0.28 to 0.47.

7.7.2 *Tribunal review of the AER's approach to estimation of gamma*

In its recent decisions in respect of Networks NSW, ActewAGL and Jemena, the AER approached the estimation of gamma in the way outlined above (although with some slightly different values for the component estimates of the distribution rate and theta). In responding to the service providers' applications for merits reviews of the AER's decisions, the Tribunal required (in its decisions handed down on 26 February 2016), that the AER's decisions on the value of imputation credits be set aside.

[91] Australian Energy Regulator, *Final Decision Amadeus Gas Pipeline Access Arrangement 2016-2021*, Attachment 4 May 2016, page 4-37.

The Tribunal found:

- in the absence of sufficient explanation for an alternative measure of the distribution rate (a measure using data from only listed equity), it is appropriate to follow past practice (estimation of the distribution rate from data for all equity);[92]
- the equity ownership approach overstates the redemption of distributed imputation credits by eligible investors; it may be useful only as providing an upper bound which, like the upper bound suggested by tax statistics, can provide a check on other estimates;[93]
- the equity ownership and tax statistics approaches make no attempt to assess the value of imputation credits to shareholders, and ignore the likely existence of factors, such as the 45 day rule, which, across all eligible shareholders, reduce the value of imputation credits to those shareholders below the face value assumed by the AER; the equity ownership and tax statistics approaches are inconsistent with a proper interpretation of the Officer framework underlying clause 6.5.3 of the National Electricity Rules, which is equivalent to Rule 87A of the NGR;[94]
- the equity ownership and tax statistics approaches can only provide upper bounds for an estimate of theta; estimation of theta must, therefore, rely on market studies which best capture the considerations that investors make in determining the worth of imputation credits to them; and[95]

[92] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [1106].

[93] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [1093].

[94] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [1095]; the Tribunal does not refer to Rule 87A but to the equivalent rule 6.5.3 in the National Electricity Rules.

[95] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [1096].

- the best estimate of theta derived by the updated SFG study (before the Tribunal) was 0.35.[96]

7.7.3 *Estimating gamma*

APTPPL has estimated gamma as the product of the distribution rate and theta.

For the distribution rate, APTPPL has used an estimate of 0.7, which has been made from Australian Taxation Office data for all equity, and which has previously been regarded as an estimate arrived at on a reasonable basis, and as representing the best estimate possible in the circumstances. It was the estimate proposed in the Rate of Return Guideline.

For theta, APTPPL has used the estimate from an implied market value study: the estimate of 0.35 from the updated SFG study which was before the Tribunal in February 2016.

In the circumstances, the best possible estimate of gamma is 0.25 (= 0.7 x 0.35).

APTPPL has, therefore, used an estimate of 0.25 for gamma in the proposed revisions to the RBP Access Arrangement.

[96] *Applications by Public Interest Advocacy Centre Ltd and Ausgrid Distribution* [2016] ACompT 1, [1103], [1113].

8 operating expenditure

This chapter sets out operating expenditure undertaken in the current access arrangement period and forecast operating expenditure for the forecast access arrangement period, and provides explanations for actual and forecast operating expenditure by reference to the Rules.

The RBP is operating in an environment with strong incentives for cost management.

Under the National Gas Law and National Gas Rules, gas transmission pipelines must offer the reference service but can also offer commercially negotiated contracts for access to the pipeline. This distinguishes gas transmission from gas distribution and electricity networks.

Consistent with the rules APA has a number of commercially negotiated contracts that use the RBP which do not pay the reference price.

These contracts provide a very strong incentive for APTPPL to manage its costs efficiently for the RBP. The contracts do not permit a rise in revenue because costs have risen. This means that if operating expenditure rises then the RBP profitability falls by the same amount. As a result APA and APTPPL have a strong focus on cost management. This can be seen in the arrangements outlined in chapter 4.

APA does not distinguish operating expenditure for the RBP based on whether it is providing a reference service or a commercially negotiated service.

The strongest indicator that these arrangements are effective is that RBP operating expenditure has remained flat over the previous access arrangement period despite operating one of the oldest pipelines in the Australia.

8.1 Operating expenditure categories

As defined under Rule 69, operating expenditure for the purposes of price and revenue regulation under the Rules means:

> *… operating, maintenance and other costs and expenditure of a non-capital nature incurred in providing pipeline services and*

> *includes expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services.*

For the purposes of the access arrangement revision proposal APTPPL classifies its operating expenditure in the following categories

- controllable costs
- non-controllable costs

8.1.1 *Controllable costs*

Controllable costs are those costs incurred by APTPPL in the operation of the RBP, over which APTPPL is able to exert a degree of influence in terms of both frequency and magnitude of costs. This control is tempered, however, by regulatory obligations and other considerations of efficiency and prudency. Typical controllable costs occur in the areas of labour, contractors engaged in the maintenance and operation of the pipeline and other operating costs.

8.1.1.1 *Labour*

Labour costs include staff salaries and wages and other employee related costs attributable to the management maintenance and operation of the pipeline, pipeline right of way, pipeline facilities, compressor stations, SCADA and communications systems and regulation, metering and gas measurement equipment. Typical maintenance activities may include planned maintenance (which is systematic maintenance undertaken to minimise whole of life costs and prevent asset failure) and unplanned (or corrective) maintenance or repair activities, where failed assets are returned to working order.

The majority of employees are covered by an Enterprise Bargain Agreement (EBA). This agreement determines the terms and conditions of employment for a fixed period of time. The basis on which these terms and conditions are set and changed are covered by the Fair Work Act 2009. This permits the terms and conditions only to be modified by agreement between the employer and relevant unions or by an arbitration decision by the Fair Work Commission.

There is currently one EBA covering APT Management Services Pty Ltd technical employees working on the RBP which is the APA Transmission Pipelines (WA, NT, QLD & MOOMBA) Enterprise Agreement 2015. This EBA covers 100% of this workforce. The EBA commenced on 21 October 2015 and nominally expires 30 June 2018.

8.1.1.2 *Contractors*

Contractors costs include costs of contracted services associated with operating and maintaining the pipeline.

8.1.1.3 *Other operating costs*

Other operating and maintenance costs include materials, management and consultancy fees and support activity costs such as procurement, stores, property, computing and communication, and operation of APTPPL vehicles.

8.1.2 Non-controllable costs

Non-controllable costs are those necessarily incurred by APTPPL but over which APTPPL has little or no direct control. Non-controllable costs may include costs imposed by external regulatory bodies. Specifically non-controllable costs include insurance, government taxes and licence fees, and corporate overheads allocated to APTPPL by its parent company, APA Group.

8.1.2.1 *Insurance*

Insurance costs are the premiums associate with the industry special risks (ISR) public liability travel and motors vehicle insurance as quoted by APA Group's independent insurance broker.

8.1.2.2 *Government taxes and fees*

APTPPL pays a variety of fees and charges to government bodies, including Queensland Department of Energy and Water Services, Department of Natural Resources and Mines and Department of Environment and Heritage

Protection. These fees and charges are set by the relevant government body and are non-negotiable.

8.1.2.3 *Corporate overheads*

Corporate overheads are those charges necessarily allocated to APTPPL by its parent company APA Group to attribute APTPPL's share of the costs associated with the management and administrative functions provided by APA Group and are discussed in detail in section 8.2.2.2.

These categories are identical to those used in the current access arrangement period to ensure consistency when comparing actual expenditure against the forecasts used to derive tariffs in the earlier access arrangement period, and comparing past and future expenditure in this proposal.

APTPPL does not use these classifications in its actual accounting and therefore some judgement has been applied in categorising historic and forecast expenditure into these classifications.

8.2 Operating expenditure over the earlier access arrangement period

The operating expenditure allowed by the AER in the current access arrangement period is shown in Table 8.1 below.

Table 8.1 also sets out actual and forecast operating expenditure incurred over the current access arrangement period adjusted for provisions, and compares incurred expenditure to that approved by the AER in its Final Decision in constant terms ($2016/17).

Table 8.1: Comparison of AER Final Decision and actual and estimated operating expenditure over the earlier access arrangement period ($m nominal)

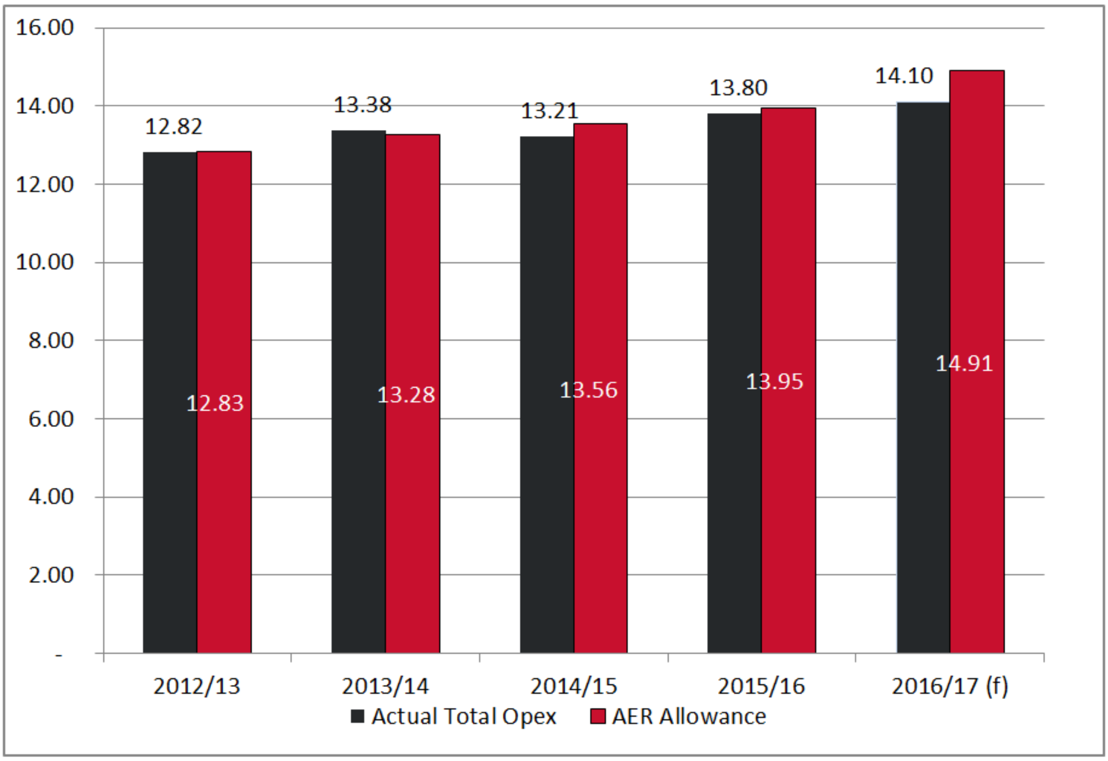
	2012/13	2013/14	2014/15	2015/16	2016/17 (f)	Total
Opex (actual and estimated)	12.82	13.38	13.21	13.80	14.10	67.31
AER Allowance	12.83	13.28	13.56	13.95	14.91	68.52
Difference	**- 0.01**	**0.10**	**- 0.35**	**- 0.15**	**- 0.81**	**- 1.22**

(f) forecast

APTPPL's total operating expenditure over the current access arrangement period was $67 million. This is below the amount approved by the AER for the earlier access arrangement period.

The similarity between the AER's allowance and APTPPL's operating expenditure for most of the current access arrangement period is further demonstrated by Figure 8.1 which compares the operating expenditure incurred with the comparable allowance from the AER.

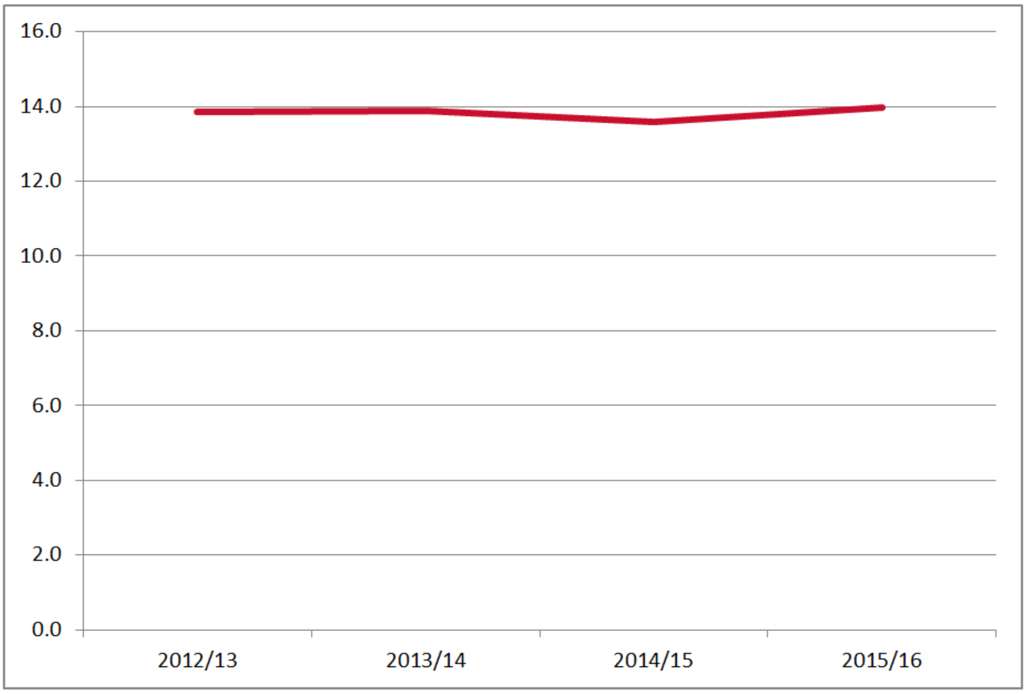
Figure 8.1: Actual Operating Expenditure compared to AER allowance ($m nominal)



(f) forecast

The total operating expenditure for APTPPL has remained very stable across the current access arrangement period. This stability is demonstrated by Figure 8.2 which plots the annual operating expenditure in real dollars.

Figure 8.2: Total operating expenditure in real dollars ($m 2016/17)



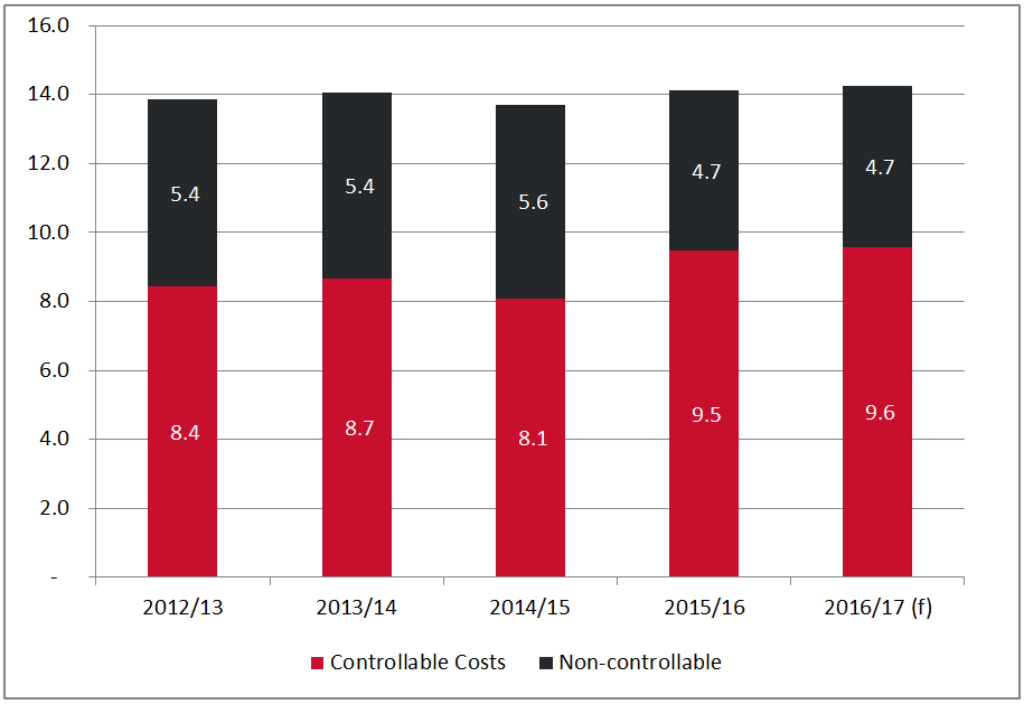
Note: Excludes MEJs and Provisions

The slight drop off in operating expenditure in 2014/15 that can be seen in this graph is the result of resources being diverted to capital expenditure projects in that year.

As noted in chapter 5 there was an increase in the emergency capital expenditure in that year relating to flooding and land slippages. This resulted in resources being diverted from operating activities to capital expenditure projects. This is most clearly demonstrated in relation to contractor costs. In 2012/13 they were $1.5m and consistent with the commencement of the capital expenditure in 2013/14 it was $1.3m. However, in 2014/15 operating expenditure on contractors dropped by $0.4m to $0.9m before returning to a more historically consistent level of $1.5m after the completion of the flood related capital expenditure in 2015/16.

Figure 8.3 displays the historic operating expenditure broken down into controllable and non-controllable costs.

Figure 8.3: Historic operating expenditure by cost category ($m 2016/17)



Note. Excludes MEJs and provisions

8.2.1 Controllable costs

Controllable costs have remained stable for the first three years of the current access arrangement period. There was a change in accounting practice that meant that certain costs that previously had been accounted for as corporate costs were now being allocated directly to the asset. More detail on this is in section 8.2.2.2.

8.2.1.1 Labour

In real terms the labour operating expenditure for APTPPL has been increasing year on year. APA's Queensland EBA had base salary increases of 4 percent from 1 January 2012, 4 percent from 1 January 2013, 1 percent from 1 January 2014 and 4 percent commencing 1 July 2015. Other changes in labour operating expenditure reflect changes in the composition and volume of labour used on projects for the RBP. There was a step up in labour costs in regard to 2015/16 this is the result of labour costs being captured to the asset rather than being treated as corporate costs more detail on this is available in 8.2.2.2.

8.2.1.2 *Contractors*

As noted above the cost of 3rd party contractors was decreasing from 2012/13 through to 2014/15 but returned to similar levels to those seen in 2012/13 in 2015/16.

8.2.1.3 *Other operating costs*

There is some volatility in other operating costs in the historic period. This is due to the nature of these costs which are made up of a number of items including:

- Carbon costs up until 2013/14
- Legal costs
- Easement materials

8.2.2 *Non-controllable costs*

Non controllable costs have been stable across the current access arrangement period. Similar to controllable costs year on year variation is to be expected for individual costs.

8.2.2.1 *Insurance, government taxes and licence fees*

APA undertakes acquisition of insurance through an insurance broker who determines which insurance contract is the most efficient way of meeting APA's insurance needs.

There were two changes in the historic insurance expenditure. In 2013/14 APA changed insurance provider following a tender. This resulted in a lower overall insurance cost, including for the RBP. This reduced the insurance cost for RBP from $0.4m to $0.3m.

In 2014/15 FM Global conducted an investigation into a number of assets and their risk profile. This investigation identified that the Dalby Compressor Station was on a major flood plain. As a result our insurer changed the premium applicable to Dalby. This changed RBP's insurance cost to $0.4m.

8.2.2.2 *Corporate overheads*

APTPPL made some changes to how it accounted for particular costs in its 2016 financial year. This approach was to identify certain costs directly with the RBP that had previously been part of the corporate cost allocation. . This revised allocation was made possible by a focus on prioritising the direct posting of costs and an upgrade to system usage and processes. In particular these costs are:

- the Queensland Training team
- the Transmission Services team
- the Transmission Project team
- short term incentives (bonuses) for field services personnel.
- the transfer of operation of APA grid from a corporate team to market services team.

While as demonstrated by Figure 8.2 this has not substantially changed the total operating expenditure, it can be seen in Figure 8.3 that it has changed the split between controllable and non-controllable costs.

Corporate Overhead allocation methodology

The APA corporate overhead allocation process starts with the audited corporate overheads as reported in APA's financial accounts. APA allocates corporate overheads to individual pipelines, networks or businesses (assets) using a two stage process

1. APA allocates those corporate overheads that can be attributed to an asset or class of assets directly to those assets.
2. Corporate overheads not allocated under step 1 (residual corporate overheads) are allocated to assets APA manages that were not included in step 1. This uses revenue as a cost allocator.

These steps are outlined in more detail below.

Step 1

APA has identified corporate overheads that it can directly allocate to certain assets as a result of the nature of corporate overhead cost and the type of the asset.

The structure of APA corporate means that certain costs incurred at the corporate level are only applicable to certain types of assets. So APA separately allocates:

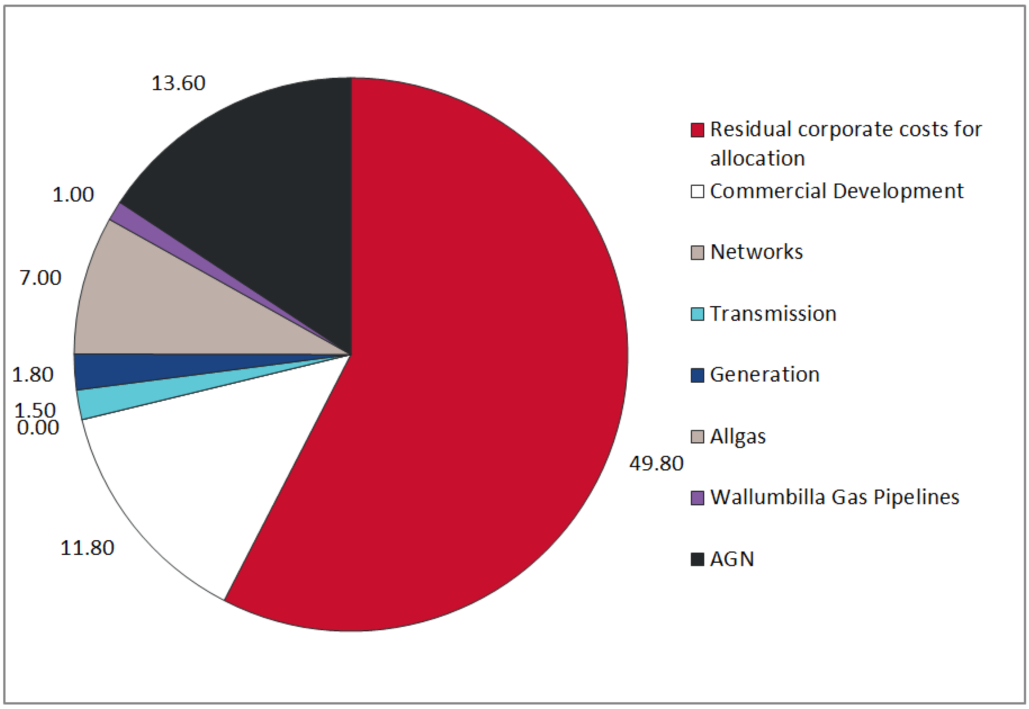
- Commercial Development costs to non- regulated assets
- Corporate transmission costs to transmission pipelines
- Corporate network costs to network assets
- Corporate power generation costs to power generation assets.

APA has direct charges for overhead costs to Allgas Networks, and Australian Gas Networks. These represent the provision of corporate services directly under these management contracts.

APA owns but does not operate the Wallumbilla Gladstone Pipeline (WGP). Recognising this APA allocates costs representing treasury costs and accounting related treasury costs and an amount for related costs of these services to the WGP.

Figure 8.4 reconciles the residual corporate costs for allocation with the total corporate costs. This reflects the corporate costs as reported by APA in its audited statutory financial accounts.

Figure 8.4: APA's 2015/16 forecast corporate overheads from financial accounts (Sm nominal)



Step 2

APA has ownership stakes in a number of assets that APA does not manage. This is because APA has either:

- A minority shareholding in which the entity provides a return to APA; or
- A majority shareholding but the operations and management are entirely contracted out to an unrelated third party.

These passive investments do not require day to day management by corporate level APA employees. Reflecting this APA excludes these entities from its allocation of residual corporate overheads to individual assets.

As noted in step 1, APA has some specific corporate overhead allocation to specific assets. For this reason APA excludes those assets from the allocation of residual corporate overheads[97]. This does not include those assets where specific costs have been identified as belonging to that class of assets, in

[97] Allgas, Australian Gas Networks and Wallumbilla Gladstone Pipeline.

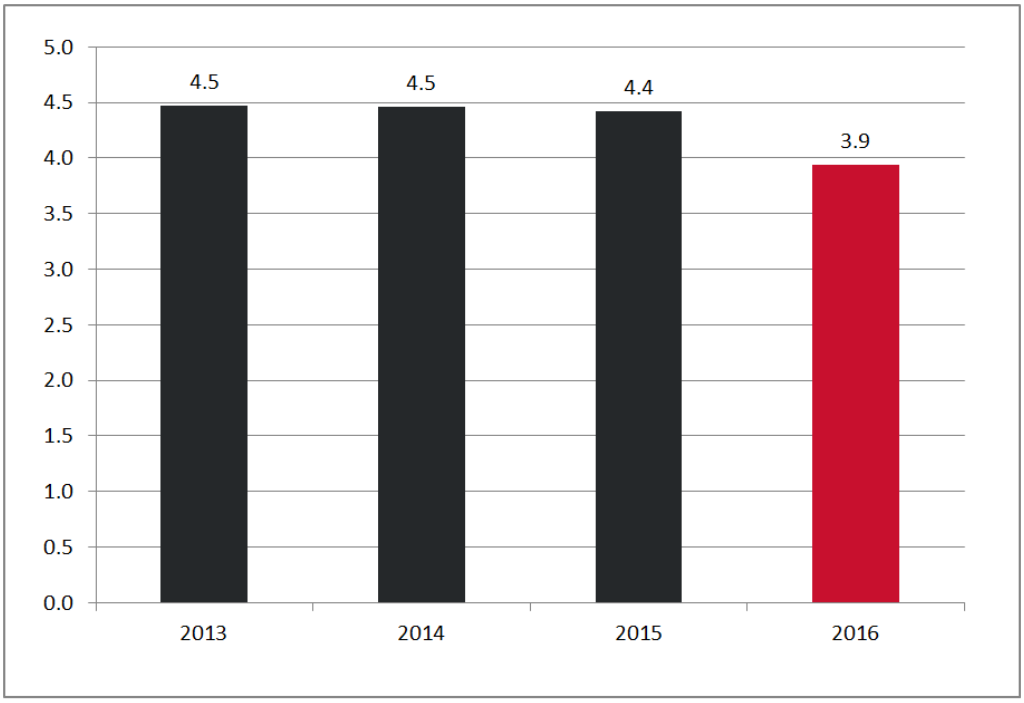
particular transmission assets are not excluded as a class from the residual corporate overhead allocation.

APA then allocates residual corporate overheads to all remaining assets based on revenue. RBP's revenue is 6.05 percent of remaining assets total revenue.

APA then takes the transmission corporate costs and allocates them to transmission pipelines based on revenue. RBP's revenue is 6.70% of transmission only revenue

Provisionally in 2016 this resulted in $3.94m (nominal) in APA corporate overheads being allocated to RBP. As noted above, there has been a change in those cost categories that are being recovered directly from RBP and those being captured at the corporate cost level. This is demonstrated by Figure 8.5.

Figure 8.5: Corporate Overheads ($m, 2016/17)



8.4 Forecast operating expenditure

8.4.1 Rules for operating expenditure

Rule 91 specifies that operating expenditure:

> *… must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of operation.*

The AER's discretion under this Rule is limited such that the AER must not withhold its approval of proposed operating expenditure if it is satisfied that the proposal complies with the requirements of the law and is consistent with Rule 91. All forecasts and estimates must also comply with Rule 74.

APTPPL has forecast its operating expenditure to ensure ongoing compliance with its regulatory obligations discussed in chapter 2, and in line with the planning and asset management processes and procedures set out in chapter 4. There are no contingency allowances included in the operating expenditure forecast. APTPPL notes that there is a material risk that some estimates will be too low owing to uncertainties in forecasting costs accurately, particularly in the later years of the access arrangement period.

APTPPL considers that its forecast operating expenditure is consistent with Rule 91 as being prudent and efficient expenditure. APTPPL further considers that its forecast has been arrived at on a reasonable basis and is the best possible in the circumstances, in accordance with Rule 74.

8.4.2 Forecast methodology

APTPPL has forecast its operating expenditure using a base year approach. The methodology to derive this forecast involves:

- identification of an efficient base year and base year costs; and
- Adjustment for step and scope changes including the removal from the base year of costs that are not indicative of future requirements and adding costs for new expenditures in future years not experienced in the past or embedded in the base year costs.

APTPPL considers that the base year approach is appropriate for APTPPL as it has displayed a stable profile of operating expenditure over recent years, and expects to maintain this profile into the foreseeable future.

Therefore, APTPPL believes that the base year approach will yield the best forecast or estimate possible in the circumstances, as it reflects the actual operating costs of the business. It should be noted that APTPPL's operating costs are subject to commercial pressures to ensure lowest cost service delivery, in particular as a result of long term contracting arrangements for the pipeline, which are not directly affected by the regulatory outcome.

8.4.3 2015/16 base year

APTPPL has used its estimated expenditure in 2015/16 as its base year for determining forecast operating expenditure over the access arrangement period. APTPPL considers that this year is appropriate for this purpose as:

- It will be the most recent completed regulatory year for expenditure and is therefore the most indicative of the current operating expenditure of the business; and
- It is in line with operating expenditure in previous years of the period.

APTPPL is a wholly owned APA Group entity, and there are no operating or management contracts in place impacting forecast operating expenditure. For the avoidance of doubt, there are no related party margins included in historic or forecast expenditure impacting the base year or the operating expenditure forecast.

APTPPL is subject to strong incentives to reduce its operating costs, including those in the base year, as its actual revenue for this asset is governed by a range of commercial contracts that are not directly linked to regulated outcomes. This means that APTPPL faces continuous incentives to reduce its operating costs year-on-year for the life of its existing transportation contracts.

In calculating its base year operating expenditure APTPPL has removed $149,000 of Major Expenditure Jobs (MEJs) as these are operating expenditure items identified for their size and non-recurrent nature.

The resulting base year operating expenditure costs used for the purposes of forecasting operating expenditure is $13.97 million ($2016/17). This value is compared to actual (unadjusted) expenditure in the operating and maintenance category in the other years of the earlier access arrangement period as set out in Figure 8.6 below.

Figure 8.6: Adjusted base year 2015/16 operating expenditure compared to other years in the earlier access arrangement period ($m 2016/17)

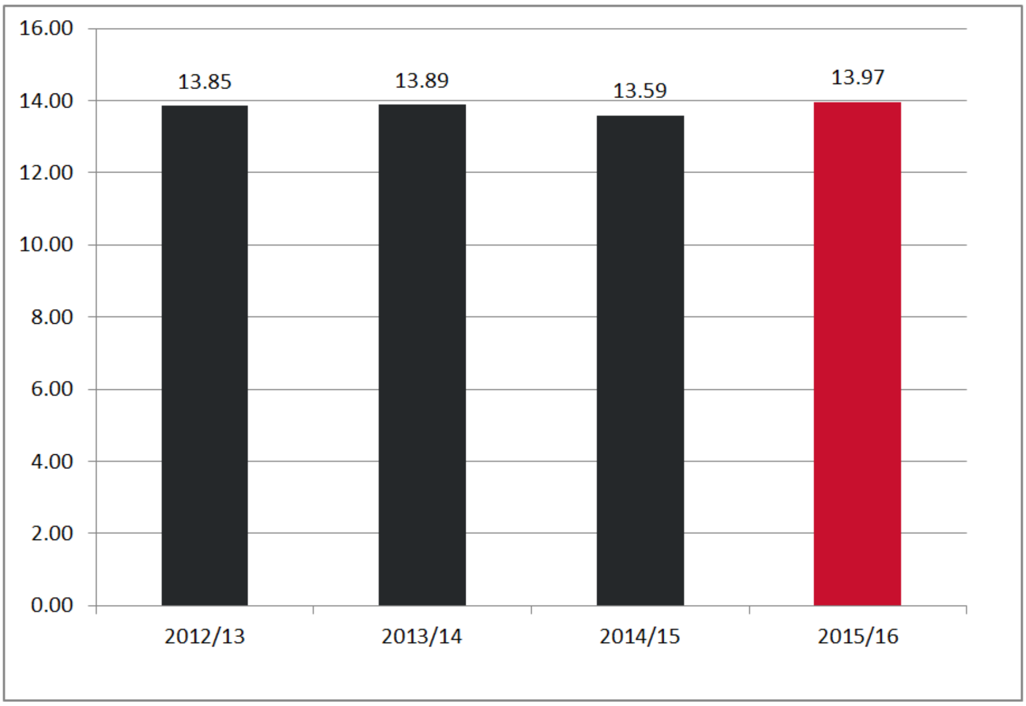


Table 8.2 sets out the historic operating expenditure for RBP across the current access arrangement period after adjustments have been made to remove provisions and major expenditure jobs.

Table 8.2: Historic total operating expenditure excluding major expenditure jobs from 2012/13 to 2015/16 ($m, 2016/17)

	2012/13	2013/14	2014/15	2015/16
opex	13.85	13.89	13.59	13.97

As Table 8.2 demonstrates APTPPL's operating expenditure has been flat over the current access arrangement period and that 2015/16 is in line with the previous years' levels of expenditure. This is despite an aging asset base which would be expected to drive higher maintenance costs. The driver of these results is efficiency gains such as:

- Refinement of right of way repairs through better dealing with root causes; and
- Utilisation of the functionality provided by EAM to refine maintenance practices.

APTPPL is therefore proposing that in real terms the trend for forecast operating expenditure is flat (a zero year on year growth rate) for the forecast access arrangement period.

8.4.4 *real cost escalation*

For the removal of doubt APTPPL is not proposing any real cost escalation.

8.4.5 *step and scope changes*

APTPPL has chosen to provide a separate forecast for two different categories of expenditure. This is for Major Expenditure Jobs and step changes.

8.4.5.1 Major Expenditure Jobs

As previously noted MEJs are specific operating expenditure projects identified for their size and non-recurrent nature. It is the nature of these projects that past expenditure is not generally an indication of likely future expenditure. APTPPL has elected to forecast MEJs on a project specific basis. APTPPL are forecasting two separate projects in the next AA period. The costs for these projects are outlined in Table 8.3.

CP interference testing and mitigation

One potential issue for cathodic protection (CP) is that the equipment can be interfered with or interfere upon third party structures. For example where CP crosses railway lines if not physically isolated the performance of the CP can be affected.

There have been a number of locations identified that require testing and mitigation as a result of recent CP unit upgrades in addition to 5 yearly CP registration expiry. This program is driven out of statutory compliance requirements.

The estimate for this is based on a refinement of the estimate we received from a 3rd party provider for this service.

Loss of cover and mitigation assessment

The depth of soil and other material between the surface and the pipeline is called the "depth of cover". There are safety considerations in relation to maintaining a minimum level of cover over the pipeline. APTPPL is about to commence a depth of cover review of its pipeline. This review will use pipe locators along the pipeline to determine whether there is sufficient cover. Where the depth of cover is identified as inadequate APTPPL will put in place sufficient material to return the depth of cover back to a satisfactory level of cover. This must be undertaken in such a way as to ensure that APTPPL complies with its safety and environmental obligations. This can be particularly important in locations where the depth of cover has been removed by water courses such as creeks.

The cost estimate is built up using estimated internal labour, contractor and material costs.

Table 8.3: Forecast MEJs ($m, 2016/17)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
CP interference testing and mitigation	0.10	0.10	0.05	-	-	0.26
Assessment of loss of cover and mitigation	0.05	0.05	-	-	-	0.10
Total	**0.15**	**0.15**	**0.05**	**-**	**-**	**0.36**

8.4.5.2 *Step changes*

AEMC fee from DEWS

Under Electricity Act 1994 as amended by the Electricity and Other Legislation Amendment Act 2014, APTPPL is required to pay the Department of Energy and Water Services a fee, representing a portion of the cost of the AEMC, to the Queensland government.

On 1 April 2016 DEWS wrote to APA to indicate that it is changing the methodology that it uses to levy its AEMC charge. This modification has resulted in an increase of $70,000 per year commencing in the 2016/17 financial year. This fee is set by the Department and APTPPL is not able to reduce it by efficient management.

We have added $70,000 to each year of our forecast operating expenditure commencing in the 2017/18 financial year.

Mining Tenement Rents from DRM

On 26 August 2016 the Department of Natural Resources and Mines (DRM) informed APTPPL that the Mining Tenement Rents had risen to $126,876. Prior to this rise APTPPL had been paying $61,442 annually. The justification for the increase provided by the DRM is an audit had revealed that they should be charging APTPPL based on a revised pipeline kilometres measurement.

8.4.6 *Total operating expenditure*

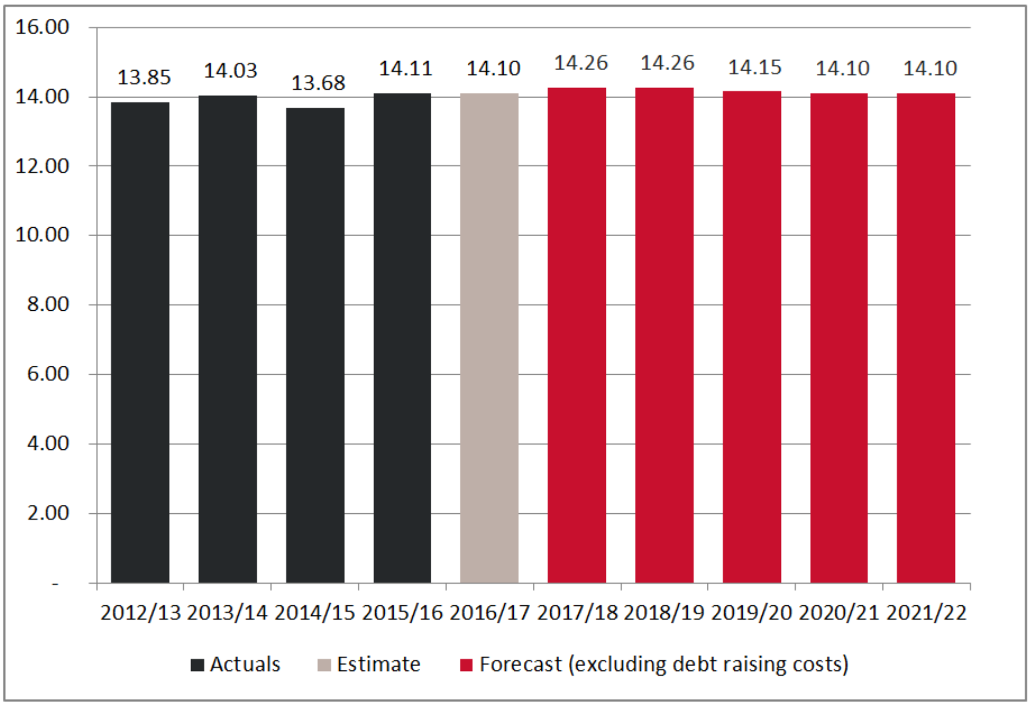
Total operating expenditure by category over the access arrangement period is set out in Table 8.4 below.

Table 8.4: total operating expenditure forecast ($m, 2016/17)

	2017/18	2018/19	2019/20	2020/21	2021/22
opex	14.26	14.26	14.15	14.10	14.10

Operating expenditure for the access arrangement period compared to the earlier access arrangement period is shown in Figure ES. below.

Figure 8.7: total operating expenditure historic and forecast ($m 2016/17)



As can be seen from the graph, total operating expenditure over the forecast period is in line with that in the earlier period. This reflects the largely recurring nature of operating expenditure.

APTPPL considers that its forecast operating expenditure for the access arrangement period satisfies the requirements under Rule 91 that it be expenditure that would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services.

Forecasts have been arrived at on a reasonable basis, using the best available information applying to the business and the pipeline.

8.5 Debt raising costs

APTPPL has also included debt raising costs, calculated using the AER's Post Tax Revenue Model, in its total operating expenditure used to derive forecast revenue for the access arrangement period. Debt raising costs, as calculated under the PTRM, are set out in Table 8.5 below.

Table 8.5: debt raising costs ($m, 2016/17)

	2017/18	2018/19	2019/20	2020/21	2021/22
Debt raising costs	0.25	0.26	0.26	0.25	0.25

8.6 outsourced expenditure

The AER RIN requires APTPPL to submit certain information related to outsourced forecast operating expenditure that contributes in a material way to the provision of pipeline services. APTPPL has very limited contracts currently in place for forecast operating expenditure. There are, however, some ongoing relationships with external providers that APTPPL expects will continue in the access arrangement period. Details of these contracts and relationships are provided in confidential Attachment 4-4.

APTPPL has applies a materiality threshold of $100 000 a threshold that gives the AER a better insight into contracting behaviour than a higher threshold would and less immaterial contracts than a lower threshold would provide.

9 total revenue

Rule 76 requires the total revenue to be derived according to a building block approach. The considerations relevant to each of the building blocks are discussed in the relevant sections above. This section summarises those building blocks to present the total revenue requirement.

9.1 Return on capital

The required return on the capital base is discussed in chapter 7. The required return on the capital base is summarised in *Table 9.1* below.

Table 9.1: Return on capital

	2017/18	2018/19	2019/20	2020/21	2021/22
Return on capital	34.84	36.44	37.19	37.33	38.10

9.2 Return of capital

The forecast straight line depreciation over the access arrangement period is discussed in section 6.2.4. To calculate the amount of regulatory depreciation applicable to the revenue requirement, the amount of indexation of the capital base must be subtracted from the straight line depreciation. The indexation of the capital base is discussed in section 6.2.5.

Together, these two amounts combine to derive the forecast regulatory depreciation as shown in *Table 9.2*.

Table 9.2: Forecast depreciation over the access arrangement period ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Straight-line depreciation	15.45	16.72	17.75	11.42	11.76
Indexation	9.03	9.45	12.05	12.09	12.34
Regulatory depreciation	6.41	7.27	5.70	-0.67	-0.59

Table 10.1 - Total revenue requirement ($m, nominal)

The depreciation schedule for establishing the opening capital base at 1 July 2022 will be based on forecast capital expenditure.

9.3 Operating expenditure

APTPPL's forecast operating expenditure is discussed in section 8.3. Amounts included in the total revenue allowance are shown below.

Table 9.3: Operating expenditure ($m nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Forecast operating expenditure	14.84	15.19	15.43	15.72	16.08

9.4 Revenue adjustments

Each year, APTPPL must lodge a tariff adjustment notification with the AER for approval, consistent with the provisions of clause 4.5 of the current Access Arrangement. This tariff adjustment notification applies the current level of inflation, and the impact of any cost pass through arrangements.

The tariff adjustment notification lodged with the AER on 23 May 2016 was affected by an arithmetical error. APTPPL wrote the AER on 14 July 2016, seeking to correct this error. The AER refused, referring to clause 4.5.5 of the current Access Arrangement:

If a past annual tariff adjustment contains a material error or deficiency because of a clerical mistake, accidental slip or omission, miscalculation or mis-description, the AER may change subsequent tariffs to account for these past issues.

In its letter, the AER directed APTPPL to address the material error or deficiency in the subsequent tariffs commencing 1 July 2017 in the Access Arrangement revision for 2017-22.

Consistent with the AER's advice, APTPPL has included this amount, in present value neutral terms, as a Revenue Adjustment in the first year of the 2017-22 Access Arrangement period.

Table 9.4 - Impact of 2016-17 tariff clerical error

	Capacity tariff	Commodity tariff	
Incorrect tariff[98]	$0.6505	$0.0436	
Corrected tariff[99]	$0.6700	$0.0449	
Difference	$0.0195	$0.0013	
Applicable load[100]	209.9TJ/day	64,953 TJ	
Dollar impact	$1,493,963	$84,439	
Total dollar impact			**$1,578,403**
One year WACC adjustment			1.0731
Total dollar impact			**$1,693,784**

9.5 Corporate income tax

As discussed in section 6.4, for the purposes of this access arrangement, APTPPL has adopted a post tax approach, in line with the requirements of the Rules. APTPPL's corporate income tax allowance is set out in *Table 9.5* below.

Table 9.5: Corporate income tax allowance ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Tax allowance	2.53	2.48	1.81	0.72	0.77

9.6 Total revenue requirement

Combining these components as required under Rule 76 derives a total revenue requirement as shown in *Table 9.6* below.

98 Letter from APTPPL to AER dated 23 May 2016.

99 Letter from APTPPL to AER dated 14 July 2016.

100 AER Final Decision PTRM August 2012, Input!K284, K286.

Table 9.6: Total revenue requirement ($nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Return on capital	34.84	36.44	37.19	37.33	38.10
Return of capital	6.41	7.27	5.70	-0.67	-0.59
plus operating and	14.84	15.19	15.43	15.72	16.08
plus revenue adjustments	1.73	0.00	0.00	0.00	0.00
plus net tax allowance	2.53	2.48	1.81	0.72	0.77
Building block revenue	**60.36**	**61.38**	**60.13**	**53.10**	**54.36**

The present value of this revenue requirement stream, discounted at the WACC of 7.7 per cent, is $233.97 million.

9.7 Incentive mechanisms

There were no incentive mechanisms in the earlier access arrangement period that have ongoing application or administrative requirements in the access arrangement period.

Looking forward, the National Gas Access Regime, defined by the NGL and Rules, focuses on reference tariffs and is therefore fundamentally a "price cap" regime.

Under a price cap regime, the service provider has clear incentives to:

- reduce operating expenditure from approved forecast levels;
- defer or avoid capital expenditure relative to the approved forecast; and
- increase the utilisation of the pipeline.

In particular, the incentive to increase the utilisation of the pipeline features prominently in APTPPL's proposed load forecast, as discussed in section 3.6.4.

Under the AER's 'revealed cost' approach, the benefits of these actions are retained by the business until the next regulatory reset, at which time they form the foundations of cost and revenue forecasts for the following access arrangement period. The benefits arising from these activities are therefore delivered to Users in the access arrangement period following that in which the activities are undertaken.

Beyond the incentives encapsulated in the Rules, APTPPL does not propose any incentive mechanism for the RBP.

10 tariffs

This chapter derives a 2017/18 Reference Tariff for Long Term Firm service of $0.6944/GJMDQ/day.

10.1 Approach to calculating RBP tariffs

Chapter 3 estimated the total forecast load and peak demand for gas transportation services on the RBP over the 2017-22 access arrangement period, including an analysis of how users would be likely to contract for gas transportation services.

This question has significant implications in the context of:

- both Long Term Firm and Short Term Firm Services being offered as Reference Services;
- the spare capacity on the pipeline (and the practical risk of Short Term Firm Services not be scheduled); and
- the need for APTPPL to have a reasonable opportunity to recover its allowed revenues in the context of s24(2) of the *National Gas Law*.

Drawing on the load and demand forecast in Chapter 3 and the calculation of Total Allowed Revenue in Chapter 8, this chapter derives a Reference Tariff for the Long Term Firm Service.

10.1.1 Expected shipper behaviour in forecast access arrangement period

(Sections 10.1.1 and 10.1.2 are duplicated from sections 3.5.7 and 3.5.8.)

It is important to distinguish the nature of Long Term Firm vs. Short Term Firm services. Long Term Firm capacity is sold subject to a take-or-pay arrangement; the shipper must pay for reserved capacity over a longer term, even if it is unutilised on a particular day. In the case of Short Term Firm services, the shipper pays only for that capacity over the short term contracted (as little as one day).

The Short Term Firm tariff is a short term capacity reservation charge rather than a long term capacity reservation charge. This has significant implications for the certainty of the pipeline owner's revenue stream.

Under a Long Term Firm capacity tariff, the shipper pays the cost of its unutilised capacity. A shipper with a low (peaky) load factor will therefore pay a higher proportion of its total cost for unutilised capacity than a shipper with a high (flat) load factor. The lower the shipper's load profile, the greater will be its preference for Short Term Firm service offerings (as short as one day) in which it is not required to pay for extended periods of unutilised capacity.

Further to the discussion above, APTPPL anticipates that those shippers with a high load factor, or with firm obligations (in particular, the large industrial and retail customers with load factors in the order of 80%) will tend to book their full requirements as Long Term Firm capacity. At the other end of the scale, peaking power plants and commodity traders, with a very low load factor, are unlikely to reserve any Long Term Firm capacity at all, and rely entirely on the availability of the Short Term Firm service.

We will therefore be required to translate the amount of Short Term Firm utilisation to a revenue-equivalent level of Long Term Firm demand, in order to calculate the Long Term Firm tariff. The Short Term Firm multiplier would then be applied to determine the Short Term Firm tariff.

This is discussed in section 10.1.2 below.

10.1.2 Relationship between Long Term Firm and Short Term Firm tariffs

The Long Term Firm Service is a capacity reservation service, under which the Service Provider undertakes to hold capacity available for the shipper's use for the duration of the contract. The Shipper is entitled to trade that capacity should it choose to do so.

As a capacity service, the tariff for the Long Term Firm Service is based on the amount of capacity reserved each day (rather than the amount used on a particular day) and therefore does not vary based on the amount of gas transported.

In contrast, the Short Term Firm Service applies to short contracting periods, potentially relating to nominations made the day prior to the transportation service being provided – no "excess" capacity is likely to be reserved under this service. Accordingly, the Short Term Firm service is charged on the basis of the amount of capacity reserved over the shorter contracting period.

Shippers choosing the Long Term Firm Service generally reserve capacity to meet their peak day demand to be sure they will have sufficient capacity available to meet their needs or meet their obligations. These shippers recognise that, as capacity is charged based on the amount reserved, there will be occasions when capacity is reserved (and paid for) but is not utilised on a particular day.

The value of the Short Term Firm Service is that it is not charged if it is not contracted. As shippers choosing the Short Term Firm Service are expected to use this service to "sculpt" their loads, they will not incur charges for capacity that is reserved but unutilised. Under this structure, it is anticipated that the Short term Firm Service will be utilised to a very high load factor, approximating 100 per cent. The Short Term Firm capacity tariff is therefore equal to a "per GJ" transportation charge.

To demonstrate the relative value of these Services, we translate the capacity charge under a Long Term Firm contract to a comparable charge that would be incurred under a Short Term Firm arrangement.

The key to this translation is the shipper's load factor. The load factor is calculated as the ratio of the shipper's average daily demand (that is, total annual throughout divided by 365) to its peak demand.

A high load factor (that is, peak demand approximately equal to average demand) is a sign of a very stable, "flat" load. This is often observed in large industrial operations. In contrast, a low load factor (peak demand is high relative to average demand) is a sign of a variable, "peaky" load. This is often observed in temperature-sensitive loads, particularly in colder climates. A low load factor is also observed in cases where gas is used opportunistically in response to variable market signals. For example, we see very low load factors in peaking power plants that respond to differentials between gas and electricity prices, and also to commodity traders that take advantage of transient market opportunities.

To convert a long term capacity tariff to an equivalent "per GJ" charge, the capacity tariff is divided by the shipper's load factor. A shipper under a Long Term Firm contract, transporting gas with a 66% load factor (its average day demand is 66% of its peak day demand), will incur an equivalent "per GJ transported" charge of 150% times the capacity tariff. This occurs because the Long Term Firm shipper pays for a certain amount of reserved capacity, which, as demonstrated by its load factor, it does not use. This is the cost the shipper incurs to have certainty that its reserved capacity will be provided on any day required (particularly its maximum day).

As discussed above, APTPPL anticipates that peaking power plants (and shippers taking the Westbound service, discussed below) will not choose to reserve firm capacity, but will choose to use the Short Term Firm service.

This presents a challenge for tariff setting where the objective is to obtain a target level of revenue. APTPPL therefore proposes to apply a tariff multiplier, determined using the forecast levels of average and peak demand to derive Short Term Firm tariffs from the posted Long Term Firm tariffs.

Box 1: Relationship between Long Term Firm and Short Term Firm

Gas transmission pipelines are constructed to provide users with firm transportation service. They are long-lived assets, and service providers will typically seek to enter into long term contracts with firm service users to ensure sufficient certainty in future revenues to secure the long term financing of the assets.

The RBP's Long Term Firm service is a capacity service, and its price can be quoted solely in terms of a number of GJ per unit of contracted capacity. There is no throughput charge, and the price a user pays, per GJ of gas delivered is:

$p^{LTF} = p^{CAP}/L$.

The Short Term Firm service is the service of delivering a user's gas on the nominated day (the day ahead). At the anticipated 100% load factor, its capacity charge is equivalent to a "per GJ transported" throughput charge.

Suppose the price per GJ of gas delivered using Short Term Firm is p^{STF}.

The RBP has sufficient spare capacity to allow users to be reasonably sure of obtaining Short Term Firm Services whenever they require pipeline capacity. In these circumstances, APTPPL is willing to provide Short Term Firm Services only when the price of Short Term Firm is equal to or greater than the price of Long Term Firm Services. If the price of Short Term Firm were less than the price of Long Term Firm, users would not contract for Long Term Firm, and would put at risk the long term financing of the pipeline.

Assuming all users have same load factor, L, the minimum price at which APTPPL will provide Short Term Firm is:

$p^{STF} = p^{LTF} = p^{CAP}/L$.

The access regulatory regime of the NGL and the NGR applies to the RBP, and the prices p^{STF} and p^{CAP} should be set to recover the present value of APTPPL's total revenue (costs) over an access arrangement period.

Suppose the access arrangement period is one year. This simplification avoids the notational complexity of the present value calculations, while retaining the key point of the argument. If q^{LTF} is the capacity contracted for Long Term Firm Service, and q^{STF} is the throughput delivered using Short Term Firm, then:

$p^{CAP} \times q^{LTF} + p^{STF} \times q^{DAF} = TR$.

If the minimum price at which the APTPPL will provide Short Term Firm is $p^{STF} = p^{CAP}/L$, then

$p^{CAP} \times q^{LTF} + p^{CAP} \times q^{STF}/L = TR$,

so that:

$p^{CAP} = TR/[q^{LTF} + q^{STF}/L]$.

That is, the Long Term Firm capacity charge, p^{CAP}, is determined by dividing the total revenue by the sum of:

- the capacity contracted for Long Term Firm; and
- the capacity-equivalent of the throughput provided using Short Term Firm, which is a multiple, 1/L, of the quantity of that throughput, where L is the load factor.

The Short Term Firm charge is $p^{STF} = p^{CAP}/L$.

In effect, 1 GJ of Short Term Firm is equivalent to 1/L GJ of contracted Long Term Firm Capacity.

APTPPL proposes to set the relationship between the Long Term Firm capacity tariff and the Short Term Firm capacity tariff in accordance with the composite pipeline load factor.

The forecast five-year average load factor calculations are presented below:

Table 10.1: Forecast five year average system load factor calculations[101]

Forecast	2017-18	2018-19	2019-20	2020-21	2021-22
Maximum demand	139.3	154.9	159.3	156.0	160.5
Average demand	90.3	92.6	93.2	93.3	93.9
Composite load factor	64.8%	59.8%	58.8%	59.8%	58.5%
Average load factor					60.3%
Forecast Short Term Firm multiplier					**166%**

APTPPL considers that the forecast composite load factor is the relevant measure to use, as it reflects the current load forecast circumstances in the context of the demand for gas and pipeline services in the SE Queensland market. APTPPL proposes to apply a factor of 166% as the relationship between the Long Term Firm Service tariff and the Short Term Firm Service tariffs for the 2017-22 access arrangement period.

Implications

It should be noted that fixing the relationship between the Long Term Firm tariff and the Short Term Firm tariff has broader consequences. As developed more fully below, a lower relative Short Term Firm tariff will encourage shippers (particularly shippers with low load factors) to abandon the Long Term Firm service in favour of the Short Term Firm service.

Within the constraint of achieving a given amount of allowed revenue in accordance with NGL s24(2), a lower multiplier will result in a higher Long Term Firm tariff. This will result in a transfer of wealth from shippers with high load factors (such as industrial and retail customers) to shippers with low load factors (such as peaking power plants and commodity traders).

[101] Data source: Acil Allen Consulting, Roma to Brisbane Pipeline, Assessment of Demand for Services, Figures 4.13 and 4.14.

10.1.3 Load forecast and tariffs

As developed in Chapter 3, the total Long Term Firm equivalent load forecast is presented below.

Table 10.2: Forecast Long Term Firm equivalent demand

TJMDQ/day	2017-18	2018-19	2019-20	2020-21	2021-22
Long Term Firm	156.5	134.5	115.8	116.1	116.2
Power Generation	3.58	7.19	8.42	8.07	8.88
APTPPL Westbound demand forecast	39.9	58.3	75.8	75.8	74.9
Long Term Firm Forecast (TJMDQ/day)	**200**	**200**	**200**	**200**	**200**

As discussed in more detail in Chapter 3, APTPPL has calculated the tariff for Firm Capacity, on the basis of an assumed aggregate Long Term Firm-equivalent capacity reservation of 200 TJ/day. This places APTPPL at considerable risk in terms of the quantity of load migrating from a firm capacity reservation tariff to a short term commodity tariff. To the extent more "peaky" loads migrate to Short Term Firm tariffs (and therefore only pay for gas transportation actually used), APTPPL will recover less revenue than forecast.

10.2 Reference tariffs

Following on from the previous discussion, the Reference Tariffs are calculated by allocating the total allowed revenue over the forecast demand.

The Long Term Firm tariff is a capacity reservation tariff, and is therefore expressed as a capacity reservation charge. In contrast, the Short Term Firm service does not require any longer term capacity reservation, and is therefore equivalent to a commodity throughput charge.

Also as discussed above, the demand forecast has been developed to reflect the anticipated Long Term Firm demand and a firm-equivalent demand for the expected use of the Short Term Firm service. This allows us to calculate a Long Term Firm tariff to which we would apply the multiplier developed in section 10.1.2 to derive the Short Term Firm tariff.

The tariffs calculated through the application of the PTRM are shown below

Table 10.3: Forecast Long Term Firm tariffs

	2017-18	2018-19	2019-20	2020-21	2021-22
Smoothed Revenue Requirement ($m)	$50.69	$54.45	$58.48	$62.82	$67.48
Long Term Firm Equivalent Demand Forecast (TJMDQ/day)	200	200	200	200	200
X Factors		-5.00%	-5.00%	-5.00%	-5.00%
Long Term Firm capacity tariff ($/GJMDQ/day)	0.6944	0.7458	0.8011	0.8605	0.9244

The Long Term Firm Capacity tariff for 2017/18 derived from this approach is $0.6944 per GJ of MDQ per day, as shown in the attached PTRM. Applying the Short Term Firm multiplier developed above then derives a Short Term Firm tariff of $1.1527 per GJ of MDQ per day.

APTPPL notes that the same Long Term Firm and Short Term Firm structure, and tariffs, apply to both Eastbound and Westbound services.

10.2.1 Deleted - Confidential

10.3 Reference tariff variation

APTPPL does not propose to modify the existing tariff variation mechanism save to allow for the annual recalculation of the relevant X factors arising from the AER's annual update of the cost of debt.

As discussed below, APTPPL proposes to include a mechanical adjustment for out turn inflation through this process as well.

10.3.1 *Adjusting for differences between forecast and outturn inflation*

As part of the building block approach, the AER's PTRM calculates "regulatory depreciation" as the net amount of straight-line depreciation on the opening capital base, less the amount of indexation on the opening capital base. The indexation on the opening capital base acts to reduce the level of allowed revenue.

The indexation on the opening capital base used in the depreciation calculation is based on the AER's forecast of inflation over the access arrangement period (note that APTPPL does not dispute the AER's methodology to estimate forecast inflation, as discussed in section 6.3).

When the AER subsequently rolls forward the capital base using its Roll Forward Model, it applies the actual out-turn inflation to the indexation of the capital base.

This presents a mis-match where the allowed revenues reflect a forecast of inflation and the roll forward of the capital base reflects actual inflation. This presents inflation risk to the business, which it is not able to manage.

If out-turn inflation is lower than the forecast of inflation used in the AER's PTRM, the regulatory depreciation building block for the next access arrangement period will be reduced by a greater amount than will be allowed for in the roll forward model - the tariff for the next access arrangement period will reflect an allowed reduction for indexation of the capital base which is not ultimately provided in the Roll Forward Model, and will be too low. Conversely, if out-turn inflation is higher than the forecast of inflation reflected in the allowed revenue calculation, the tariff for the next access arrangement period will be too high.

Furthermore, if actual inflation turns out to have been lower than the forecast of inflation used in the AER's PTRM :

(a) under the AER's indexed straight line method of depreciation, the return of capital used to determine the current reference tariff will be too low;

(b) when the AER rolls forward the capital base for the next access arrangement period using, as it does, the actual inflation for the current period, the return of capital taken into account in the roll forward will be higher than was actually allowed in reference tariff determination for the current period, and the capital base at the commencement of the next period will be lower than is consistent with the return of capital allowed in tariff determination; and

(c) the service provider will be precluded from recovering a part of its capital base.

If out-turn inflation is higher than forecast, the opposite outcome obtains: the depreciation used to determine the current reference tariff will be too high, because depreciation is too high, the service provider will over-recover its capital base, and CPI adjustment of the reference tariff in accordance with the tariff variation mechanism will shift the reference tariff up at a time when capital recovery via indexed straight line depreciation is decreasing.

10.3.1.1 Impact

As shown in the table below, the discrepancy between the use of forecast inflation for revenue calculation purposes and outturn inflation for asset base roll forward services is material, and has resulted in a loss of value to APTPPL in excess of $10 million of the 2012-17 access arrangement period.

Table 10.4: Impact of differences between forecast and out turn inflation

$million, nominal	2012-13	2013-14	2014-15	2015-16	2016-17	Total
AER forecast inflation rate	2.55%	2.55%	2.55%	2.55%	2.55%	
Indexation reflected in Regulatory Depreciation[102]	10.65	10.64	10.60	10.51	10.42	**52.82**
Out turn inflation rate	2.50%	2.93%	1.33%	1.31%	2.00%[103]	
Indexation reflected in Roll Forward Model	10.44	12.27	5.66	5.72	8.70	**42.79**
Difference	**-0.21**	**1.63**	**-4.94**	**-4.79**	**-1.72**	**-10.03**

Over the 2012-13 to 2016-17 period, the AER's approach to forecasting a single inflation rate for capital base indexation and regulatory depreciation purposes has resulted in reference tariffs being reduced by $52.82 million over the access arrangement period, whereas only $42.79 million was added to the capital base through out-turn indexation.[104] This represents a loss in value to APTPPL of $10.03 million.

While APTPPL does not seek recompense for this historical loss of value, it is important to ensure that this calculation anomaly not be allowed to persist.

10.3.1.2 Proposed approach

APTPPL considers that a better approach would reflect the observed changes in inflation as reference tariffs are varied. In the gas regulatory framework (in contrast to that applying to the electricity industry), this could

[102] PTRM Assets! row 471.

[103] RBA forecast applied in most recent Amadeus Gas Pipeline access arrangement decision.

[104] APTPPL accepts that some of this difference will be impacted by differences between forecast and actual capital expenditure. However, APTPPL's actual capital expenditure is not materially different from the AER-approved forecast.

be accomplished through the Access Arrangement Tariff Variation Mechanism, within the process now being implemented by the AER for annual update of the tariff for changes in the return on debt. Minor changes would be required to the PTRM to allow inflation to vary during the access arrangement period, as discussed below.

It is important to note that, in contrast to the *National Electricity Rules,* the *National Gas Rules* do not require gas businesses to apply the AER-promulgated PTRM to develop the forecast allowed revenue. In practice, APA Group entities voluntarily apply the AER's PTRM to ease the regulatory analysis process for all parties.

As the *National Gas Rules* do not require the use of the AER-promulgated PTRM, it is open to APTPPL and the AER to make minor modifications to the AER's PTRM to accommodate this mechanical anomaly, and apply this adjusted model for the purposes of revenue determination going forward.

As discussed below, the adjustment is indeed very minor, as the regulatory framework already requires annual adjustment to the revenue path for changes to the cost of debt. APTPPL simply proposes to include the changes in out-turn inflation in this adjustment process.

The latest version of the AER's PTRM includes provision to update the allowed cost of debt annually. This has been implemented through formula changes in the model to accommodate updates to the cost of debt on the PTRM Input page:[105]

Figure 10.1: Current AER PTRM 'PTRM Input' page

	ABCD	E	F	G	H	I	J	K
422		**Cost of Capital**						
423				**2017-22**				
424		Inflation Rate	f	2.30%				
425		Return on Equity	Re	8.40%				
426		Value of Imputation Credits (gamma)	γ	25%				
427		Proportion of Debt Funding	D/V	60%				
428								
429				**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
430		Trailing Average Portfolio Return on Debt		7.26%				
431								
432								
433				The trailing average portfolio return on debt must be entered up to the year of update (ie. ye				

[105] The illustrative screen shots in this section are taken from the PTRM lodged with this submission.

APTPPL proposes adding an additional input line in row 431 of the PTRM Input page, as shown below. As this row is currently blank, it is not necessary to insert a new row to the model, relieving concerns regarding the integrity of other model formulae.[106]

Figure 10.2: Proposed PTRM 'PTRM Input' page

	ABCD	E	F	G	H	I	J	K
422	Cost of Capital							
423				2017-22				
424		Inflation Rate - WACC	f	2.30%				
425		Return on Equity	Re	8.40%				
426		Value of Imputation Credits (gamma)	γ	25%				
427		Proportion of Debt Funding	D/V	60%				
428								
429				2017-18	2018-19	2019-20	2020-21	2021-22
430		Trailing Average Portfolio Return on Debt		7.26%				
431		Inflation rate - Assets		2.00%	2.00%	2.50%	2.50%	2.50%
432								
433				The trailing average portfolio return on debt and out turn inflation must be entered up to the				

The AER's PTRM currently links the inflation figures in row 6 of the 'Assets' tab to the "full period" forecast of inflation in 'PTRM Input'G424. APTPPL proposes that the rate of inflation in the 'Assets' tab would be linked, year by year, to the new forecast inflation inputs in 'PTRM Input'G431:K431 as shown below:

Figure 10.3: Proposed link from 'Assets' page to 'PTRM Input' page

	A	B	C	D	E	F	G	H	I	J	K
4	Year					2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
5											
6		Inflation Assumption (CPI % increase)					2.00%	2.00%	2.50%	2.50%	2.50%
7		Cumulative Inflation Index (CPI end period)				100.0%	102.0%	104.0%	106.6%	109.3%	112.0%

Over the access arrangement period, the out-turn inflation figures would be updated in row 431 of the 'PTRM Input' tab in the same manner as the out-turn cost of debt is updated in row 430. That is, by replacing, in the PTRM, the forecast of inflation for the year preceding the year for which the reference tariff is annually updated, with the actual inflation for that year. The annual tariff adjustment would then take place in the same manner as the AER's current procedures.

If the reference tariff is to be updated for the regulatory year commencing 1 July, the actual inflation for the year preceding the year for which the reference tariff is to be updated would be measured as the year-on-year

[106] The particular inflation values used in this illustration are discussed below.

change in the December quarter CPI (the same measure of CPI applied to the X Factors for annual tariff adjustment purposes).

APTPPL proposes that the Tariff Variation Mechanism, should remain unchanged from that applying to the previous access arrangement period (that is, a CPI-X framework), with the exception that "X" is to be defined as follows:

X is the X factor for each financial year of the 2017–22 access arrangement period as determined in the PTRM as approved in the AER's final decision, and annually revised for the changes in the Consumer Price Index and the return on debt update calculated for the relevant financial year during the access arrangement period in accordance with that approved in the AER's final decision.

10.3.1.3 Improving the ongoing forecast of inflation

In the Amadeus Gas Pipeline Final Decision, the AER determined a forecast inflation rate as follows:[107]

Table 3-23 AER estimate of expected inflation (per cent)

Expected inflation	June 2017	June 2018	2018 to 2025	Geometric average
AER draft decision	2.5 [a]	2.5 [a]	2.5	2.50
AER final decision update	2.0 [b]	2.0 [b]	2.5	2.39

Source: RBA, *Statement on Monetary Policy*, August 2015, p. 67; RBA, *Statement on Monetary Policy*, May 2016, p. 61.

(a) In August 2015, the RBA published a range of 2–3 per cent for its June 2017 and June 2018 CPI inflation forecasts respectively. Where the RBA published ranges, we select the mid-points.

(b) In May 2016, the RBA published a range of 1.5–2.5 per cent and a range of 1.5–2.5 per cent for its June 2017 and June 2018 CPI inflation forecasts respectively. We select the mid-point from this range.

In summary, the AER's approach is to adopt the near-term forecast of inflation released by the Reserve Bank of Australia, and apply the mid-point of the Reserve Bank's target range for the outer years in which no explicit

[107] AER, Final Decision, Amadeus Gas Pipeline Access Arrangement 2016 to 2021 Attachment 3 – Rate of return, May 2016, p3-149.

forecast is available. The average inflation rate is determined by calculating the geometric average over a ten-year period.

APTPPL accepts that the AER's Rate of Return framework fixes the return on equity for the entire access arrangement period, and therefore an expected rate of inflation for the entire access arrangement period is required. APTPPL does not take issue with the methodology applied for estimating the forecast rate of inflation for the purposes of determining the allowed return on equity.

However, as the PTRM applies indexation to each year of the access arrangement period individually, APTPPL considers that an annual forecast of inflation, to the extent one is available, is preferable in the context of Rule 74.

APTPPL considers that the current RBA forecast of inflation for the year for which the reference tariff is to be updated for the year ahead is the best available forecast of inflation for that year, and should be used. That forecast will be the forecast from section 6 (Economic Outlook) of the RBA's February Statement on Monetary Policy.

For subsequent regulatory years of the access arrangement period, the inflation forecast should be:

(a) the forecasts from section 6 of the RBA's Statement on Monetary Policy; and

(b) for those years for which the access arrangement period extends beyond the period of the most recent RBA forecasts, the mid-point of the RBA target range for inflation.

APTPPL considers that, similar to the approach on the cost of debt, the forecast of inflation should be updated at each annual tariff update. For example, in the 2018 tariff update, the Reserve Bank forecasts for the 2018-19 and 2019-20 years should be input to the PTRM Input page.

11 non-tariff components

11.1 Terms and conditions

11.1.1 Rule requirements

Under rule 48 a full access arrangement must specify for each reference service the reference tariff and the other terms and conditions on which the reference service will be provided.

11.1.2 Other terms and conditions

The full terms and conditions for the RBP access arrangement are attached to the proposed revised access arrangement.

In this access arrangement revision APTPPL are only proposing amendments to the terms and conditions relating to scheduling and curtailment. These changes reflect the introduction of the Short Term Firm reference service. More detail on this is available in chapter 2.

11.1.3 Overview of updates to terms and conditions

An overview of the updates to the Terms and Conditions in included as Appendix B.

11.2 Queuing requirements

Access to spare capacity in the RBP for the provision of pipeline services, and access to developable capacity, are currently on a first come, first served basis.

APTPPL proposes replacing the current queuing requirements with a scheme in which a prospective user may access capacity in the pipeline by:

- lodging with APTPPL a registration of interest in services to be provided by spare capacity and/or developable capacity, which remains valid for 12 months but does not assign to the prospective user any priority in gaining access to capacity;
- if sufficient spare capacity becomes available, participating in an open season process to allocate the spare capacity among all prospective users;
- if the demand for capacity is strong, and the requirements of all prospective users cannot be met from the available spare capacity, participating in a capacity auction; and
- negotiating with APTPPL to determine the required scale and scope of investment in developable capacity if prospective user requirements can only be met by developing capacity in the RBP.

11.2.1 Rule requirements

Rule 103 requires that an access arrangement for a transmission pipeline contain queuing requirements, the purpose of which is to create a process or mechanism (or both) for establishing an order of priority between prospective users for spare or developable capacity in which all prospective users are treated on a fair and equal basis.

Queuing requirements are to be sufficiently detailed to enable a prospective user to understand the basis on which the order of priority is determined and, if a queue has been established, to determine the prospective user's position in the queue (Rule 103(5)).

A prospective user's right to request access to capacity, and the process in accordance with which the service provider is to respond to the access request, are set out in Rule 112.

11.2.2 Issues with first come, first served queuing requirements

Rule 103(4) identifies first come, first served as an example of a queuing requirement, but any queuing requirement which is to be given effect in an access arrangement must satisfy the relevant requirements of the NGL and the NGR.

A first come, first served queuing requirement takes no account of a service provider's costs of service provision, or of prospective users' valuations of the service.

Example 1

Prospective User 1 (PU 1) requests 5 TJ/d of existing capacity for the period 2019 to 2024. Prospective User 2 (PU 2) requests 15 TJ/d of existing capacity for the period 2019 to 2029. Both requests are for capacity to provide the reference service at the reference tariff, and both are correctly completed. PU 1's request is submitted before the request from PU 2.

15 TJ/d of capacity, which can be used to provide the reference service, becomes spare.

Under first come, first served queuing requirements, PU 1 has priority and is allocated 5 TJ/d. PU 2 has a project which requires 15 TJ/d if it is to proceed, and is not willing to accept 10 TJ/d.

The outcome is an inefficient use of pipeline capacity. If no other prospective user applies, there will be uncontracted capacity of 10 TJ/d from 2019. Furthermore, there may be uncontracted capacity once PU 1's transportation agreement terminates in 2024.

If the net economic benefit of PU 2's project is expected to exceed the net benefit from capacity allocation to PU 1, the outcome is not in the interests of users and consumers of natural gas.

Example 2

PU 1 requests 10 TJ/d of capacity for provision of the reference service over the period 2022 to 2025. PU 2 requests 10 TJ/d, for a negotiated service at a negotiated tariff, for the period 2019 to 2029. PU 1 has priority over PU 2, and spare capacity of 10 TJ/d is available from 2019.

Under first come, first served queuing, PU 1 is allocated 10 TJ/d in 2022. PU 2's project cannot proceed.

The outcome is an inefficient use of pipeline capacity. Capacity is unused between 2019 and 2022. Furthermore, if the net economic benefit of PU 2's project is expected to exceed the net benefit from capacity allocation to PU 1, the outcome is not in the interests of users and consumers of natural gas.

From the perspective of a prospective user, securing pipeline capacity is usually only one of a number of activities which must be completed as part of project implementation (which might be development of a gas fired power station, or development of such a power station as part of a larger industrial or minerals processing project). Where securing pipeline capacity is part of a larger project, the project proponent will usually seek to join the queue for capacity at an early date but will avoid committing to capacity until capacity is "on the critical path" for its project. A prospective user may be at the front of the queue, but not ready to contract for capacity. Another prospective user may be further back in the queue and, because the other parts of its project have progressed quickly, may be ready to contract for capacity but cannot be accommodated until arrangements have been concluded with the prospective user at the front of the queue. That user will usually be reluctant to lose its priority by formally withdrawing its application for capacity, and the operation of a first come, first served queuing policy can become administratively difficult and imposes costs on those prospective users who must wait.

This problem is exacerbated when there is no cost to a prospective user joining the queue, and where prospective users at the front of the queue want to take capacity later and/or for shorter periods than those further down in the queue.

A first come, first served queuing policy does not allow the flexibility for higher value projects to take precedence over lower value projects when it is not possible to meet the needs of both.

If capacity must be developed, the coordination of queuing and capacity allocation becomes difficult due, in part, to the sequential nature of the process under a first come, first served policy. Expansion to meet the timing requirements of individual prospective users becomes difficult to achieve.

In consequence, the existing first come, first served queuing requirements of the RBP Access Arrangement cannot lead to the efficient allocation of spare or developable capacity. There is no reason to expect that first come, first served queuing will promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers.

11.2.3 *Approach to queuing*

APTPPL proposes replacing the existing first come, first served queuing requirements with the following processes through which prospective users may access capacity in the RBP.

These processes can be initiated by a prospective user lodging, with APTPPL, a registration of interest in services to be provided by spare capacity and/or developable capacity. A registration of interest remains valid for 12 months, but does not assign to the prospective user any priority in gaining access to capacity.

If less than 2 TJ/d of capacity becomes spare, APTPPL may allocate that capacity to prospective users on a first come, first served basis.

If 2 TJ/d, or more, of capacity becomes spare, APTPPL may initiate an "open season" process to allocate that capacity among prospective users. If there is sufficient demand for capacity, and the requirements of prospective users cannot all be met from the available spare capacity, APTPPL may hold a publicly notified capacity auction.

If prospective user requirements can only be met by developing capacity in the RBP, APTPPL will carry out investigations, and will negotiate with prospective users to determine the required scale and scope of investment in developable capacity.

11.2.4 *Existing capacity*

11.2.4.1 *Open season*

If 2 TJ/d, or more, of capacity becomes spare, APTPPL will issue spare capacity notices to all prospective users who have lodged registrations of interest, and will publish spare capacity notices in local and national daily newspapers.

Prospective users – both those who have lodged registrations of interest, and those responding to the spare capacity notices published in the newspapers – should submit expressions of interest in pipeline services provided using the spare capacity by the closing date specified in the spare capacity notices.

Where all of the pipeline services in question can be met using the available spare capacity, APTPPL will enter into negotiations with each of the prospective users who has submitted an expression of interest for access to capacity for the provision of the services sought.

11.2.4.2 *Capacity auction*

If all of the pipeline services sought through expressions of interest cannot be met using the available spare capacity, and APTPPL determines that there is sufficient demand, APTPPL will notify each of the prospective users who has submitted an expression of interest that the service provider will accept bids for the available spare capacity.

The form, and timing of submission, of a complying bid are set out in section 6.2.3(d) of the RBP Access Arrangement.

A complying bid is deemed to be an irreversible request for capacity that is capable of immediate acceptance by APTPPL.

If all of the complying bids can be satisfied from the available spare capacity, APTPPL will contract with each bidder who has submitted a complying bid.

If there is insufficient spare capacity to satisfy all of the complying bids, APTPPL will rank the bids (highest to lowest) according to the present values of the services being sought, and will allocate the available spare capacity to the highest ranked bids.

11.2.5 *Developable capacity*

If user requirements for pipeline services can be satisfied only by developing capacity, APTPPL may carry out an investigation to determine the required scale and scope of investment in developable capacity.

APTPPL will carry out the investigation needed to determine whether capacity can be developed for the provision of pipeline services only if a prospective user agrees to bear, or if multiple prospective users agree to bear, the costs of the investigation. Prospective users who bear the costs of an investigation will have priority in respect of access to capacity ahead of prospective users who decline to bear those costs.

If APTPPL determines, from the registrations of interest which have been lodged and the investigation undertaken, that the development of capacity is technically and economically feasible, APTPPL will enter into negotiations with prospective users for access to the developable capacity.

APTPPL must invest to develop capacity in the RBP if that development is technically and economically feasible, and consistent with the safe and reliable operation of the pipeline, but cannot be required to:

- fund an expansion of pipeline capacity; and
- extend the geographical range of the pipeline.

11.2.6 *Key features of the processes for accessing capacity in the RBP*

The key features of the proposed queuing requirements are:

- APTPPL will accept expressions of interest in existing capacity; these expressions of interest will not be associated with any ranking or priority of access to capacity;
- APTPPL will confirm with each prospective user that it has received that user's expression in interest, inform the prospective user of any available spare capacity and of whether investigations are required to confirm spare capacity, and provide details of other registrations for capacity received from other prospective users (without disclosing prospective user confidential information);
- APTPPL will notify all users and prospective users who have filed expressions of interest, and may advise other potentially interested parties, that an auction of existing capacity is planned;
- APTPPL will advertise the auction in local and national newspapers;
- all prospective users (those who have filed expressions of interest, and those responding to GGT's advertising) will be asked to submit bids which specify demand, volumes, commencement and end dates, and receipt and delivery points;
- bids may be for the Long Term Firm service at the reference tariff for that service, or for negotiated service for which the user proposes a negotiated tariff;

- prospective users will also be required to meet prudential requirements;
- bids are to be irrevocable, and submitted in the form of an executable contract;
- Prospective users may consult with APTPPL on the acceptability of potential alternative terms and conditions prior to submitting a bid;
- once the period allowed for the auction has expired, APTPPL will rank the bids on a net present value (NPV) basis, with bids which have a higher NPV ranked ahead of bids with a lower NPV; and
- the available existing capacity will be allocated to prospective users in turn, based on the NPV ranking, until all of the existing capacity is allocated.

A queuing requirement of this form represents a mechanism (that is, an auction) and a process which will determine the priority between competing requests for existing capacity at the time at which the auction is conducted.

The auction is a multi-stage (non-binding bids, followed by binding bids), first-price sealed bid auction for a complex service (capacity, location of delivery point, duration, tariff) with multiple winners.

APTPPL considers that the adoption of a public auction of this form will better meet the national gas objective than a first come, first served queuing policy.

An auction should promote the efficient use of natural gas services by ensuring that existing capacity is allocated to those users who value it most, and should, therefore, allocate capacity in a way that is in the long term interests of consumers with respect to price, reliability and security of supply. A first come, first served queuing policy does not allocate capacity according to user valuation and there is no reason to expect that it will promote the efficient use of capacity.

However, to be effective in achieving the efficient use of capacity, the form of the auction should preclude collusion among prospective users, encourage competition among them, and provide prospective users with as much information as is possible about the service being auctioned.

The initial stages of the mechanism and process – submission of non-binding expressions of interest, and notification of all users and prospective users who have filed expressions of interest, and other interested parties, that an auction of capacity is planned – are important for the provision of information to bidders and potential bidders.

Advertising the auction widely, and use of a sealed-bid format, should encourage competition in bidding, and the sealed-bid format should also limit opportunities for collusion among prospective users.

Requiring that prospective users meet prudential requirements is a practical efficiency measure. If the winning bidder were not financially viable, the auction would have to be held again, and the costs would be the cost of the second auction plus the costs of delay subsequently faced by all prospective users.

The submission of bids for the Long Term Firm service at the reference tariff for that service ensures that prospective users are protected from being required to pay more than the reference tariff for service. Moreover, for negotiated services the tariff paid for the capacity will be determined by the auction, and will not be set by APTPPL. A tariff will not be imposed on a prospective user by a pipeline service provider who might be perceived as being able to exercise market power.

11.2.7 *Earlier concerns about queuing requirements incorporating an auction process are unwarranted*

APTPPL proposed queuing requirements incorporating an auction process in its October 2011 Access Arrangement revisions proposal for the RBP. These were similar to (but not the same as) the queuing requirements now being proposed. The AER had a number of concerns about the earlier proposal, and APTPPL subsequently reverted to a first come, first served scheme for accessing existing pipeline capacity.

In 2012, APTPPL may have reverted to first come, first served queuing for existing capacity in the RBP, but the inherent inefficiency of establishing priority to capacity on that basis remains. APTPPL has, therefore, continued to develop queuing requirements which incorporate an auction process, and has now has seen its current version of those requirements accepted by the ERA (in June 2016) for the Goldfields Gas Pipeline in Western Australia.

The queuing requirements now proposed for the RBP are those which were accepted by the ERA in June 2016. In its earlier Draft Decision on proposed revisions to the Access Arrangement for the Goldfields Gas Pipeline, the ERA concurred with the concerns about the efficiency of first come, first served queuing noted in section 11.2.2 above, and with the efficiency of an auction when there was insufficient spare capacity to meet the needs of all prospective users:

> *1714. The Authority agrees with GGT's concerns regarding the first-come-first-served queuing policy and its possible impediments to the efficient capacity utilisation of the GGP.*
>
> *1715. The Authority considers that GGT's proposal for a queuing policy for existing spare capacity based on the capacity requirements, demand, volumes, commencement and end dates, and receipt and delivery points proposed by prospective users has a number of merits. GGT's concerns regarding the efficiency of pipeline utilisation in the face of potentially competing requests for access will be addressed if its proposed amendments are implemented. The implementation of the auction method in cases where there is insufficient capacity to meet the needs of all prospective users will, as submitted by GGT, also ensure that the pipeline is utilised by users who place the highest value on its use.*[108]

Although the ERA accepted the queuing requirements which APTPPL is now proposing for the RBP, the ERA did not address all of the concerns which the AER had in 2012. These concerns were:

- the role and effectiveness of the arbitration process established by the NGL and the NGR may be diminished under an auction process;
- an auction process would not promote efficient outcomes in accordance with the revenue and pricing principles, and may not promote the efficient operation and use of the pipeline, or efficient investment in capacity, in accordance with the national gas objective;

[108] Economic Regulation Authority Western Australia, *Draft Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 17 December 2015.

- APTPPL's requirement that users and prospective users lodge compliant bids may not result in users and prospective users being treated on a fair and equal basis in accordance with the requirement of Rule 103(3);
- a one-shot approach involving irrevocable bids may not promote efficient use of the pipeline;
- bidders may face difficulty in forming valuations for an imprecisely defined product, and efficient allocations may be less likely;
- there may not be sufficient detail to enable prospective users to understand the basis on which an order of priority between them has been, or will be, determined, and if an order of priority has been determined, there is not sufficient detail to allow a prospective user to determine its position in the queue; both of these are mandatory requirements under Rule103(5);
- the circumstances in which APTPPL will hold an auction are not clear;
- the amounts of spare capacity to be offered on the spare capacity register, to made available in an open season round, or to be auctioned, are unclear;
- APTPPL has not specified how it will determine whether to negotiate with prospective users, or use an auction, to allocate developable capacity which is to be made available; and
- there are inconsistencies in certain clauses of APTPPL's proposed queuing requirements.

A number of these concerns were unwarranted in 2012, and some were based on incorrect assessments of APTPPL's proposal. APTPPL has, since 2012, amended its proposed queuing requirements incorporating an auction process. To the extent that the AER's earlier concerns might arise in the context of assessing the queuing requirements now proposed for the RBP, they are unwarranted. The reasons why are set out below.

Role and effectiveness of access dispute resolution process

In 2012, the AER expressed concern that incorporation of an auction process in the queuing requirements for the RBP would diminish the role and effectiveness of the arbitration process established by the NGL and the NGR.

Any queuing requirements should not, the AER contended, preclude the service provider, users, and prospective users from accessing the dispute resolution process made available through the access regime.

The queuing requirements which APTPPL now proposes cannot, and do not, diminish the role and effectiveness of the arbitration process established by the NGL and the NGR. The RBP Access Arrangement explicitly provides for the negotiation of the terms and conditions of pipeline access. If the parties cannot agree, there is nothing which precludes the arbitrator from making an access determination which imposes the reference service terms and conditions and the reference tariff. In making an access determination, the dispute resolution body must give effect to the applicable access arrangement (NGL, section 189).

If less than 2 TJ/d of capacity becomes spare, APTPPL will allocate that capacity to prospective users on a first come, first served basis. A prospective user of this capacity may request Long Term Firm service, or it may negotiate terms and conditions of access. In either case, if a dispute were to arise between a prospective user and APTPPL about one or more aspects of access to capacity for a service to be provided using the RBP, the prospective user has recourse to the arbitration process established by the NGL and the NGR.

If 2 TJ/d, or more, of capacity becomes spare, APTPPL will initiate an open season process to allocate that capacity among prospective users. If all of the pipeline services sought through that process can be met using the available spare capacity, APTPPL will enter into negotiations with each of the prospective users who has submitted an expression of interest for access to pipeline capacity. A prospective user may request the Long Term Firm service, or it may commence negotiations on terms and conditions of access. Again, in either case, if a dispute arises about one or more aspects of access to a service to be provided using the RBP, the prospective user has recourse to the arbitration process established by the NGL and the NGR.

If there is sufficient demand for capacity, and the requirements of prospective users cannot all be met from the available spare capacity, then APTPPL will hold a capacity auction. Some prospective users may submit bids, in response to APTPPL's notice of auction for spare capacity, for access to capacity on the terms and conditions of the Long Term Firm service (the terms and conditions will be the Access Arrangement terms and conditions for that service). Others may structure the terms and conditions of their bids to meet their own specific requirements. If the pipeline capacity required to satisfy the bids does not exceed the spare capacity available, each bid for will be deemed to be an irrevocable request for spare capacity capable of immediate acceptance. Since the prospective shipper has specified the terms and conditions in its bid, the likelihood of an access dispute is considerably diminished. Nevertheless, should a dispute arise, the prospective user has recourse to the arbitration process established by the NGL and the NGR.

If the total of the capacity required to satisfy the bids made in response to a notice of auction for spare capacity exceeds the spare capacity available, APTPPL will rank the bids in terms of the present values of the expected revenue streams, allocating capacity to, and contracting on the terms and conditions specified in the bids, with the prospective users who have submitted the highest ranked bids. Again, since the prospective shipper must specify the terms and conditions in its bid, the likelihood of an access dispute is diminished. Nevertheless, should a dispute arise, the prospective user has recourse to the arbitration process established by the NGL and the NGR.

In all cases (allocation of less than 2 TJ/d, open season and auction) a prospective user has recourse to the access dispute resolution process of the process established by the NGL and the NGR. Irrespective of the mechanism whereby spare capacity is allocated, a prospective user's legal right to dispute resolution under the NGL remains effective.

The AER referred, in 2012, to:

- the arbitrator terminating an access dispute, under section186(2) of the NGL, without making an access determination if it considered that the dispute was based on an aspect of access expressly or impliedly dealt with under a contract between the parties; and
- the arbitrator not making an access determination, in accordance with section 188 of the NGL, that was contrary to the rights of the parties under a contract which existed at the time the access dispute arose.

Sections 186(2) and 188 of the NGL are general provisions which, respectively:

- allow the dispute resolution body to terminate a dispute which is more appropriately dealt with in another way; and
- require the dispute resolution body to recognise certain pre-existing contracts.

They are not limited by any particular method of allocating capacity to prospective users. The application of sections 186(2) and 188 of the NGL is not (indeed, cannot) be limited by APTPPL's proposed auctioning of spare capacity.

There are no grounds for concern that incorporation of an auction process in the queuing requirements for the RBP would diminish the role and effectiveness of the arbitration process established by the NGL and the NGR.

An auction process would not promote efficient outcomes

The AER's conclusion, in 2012, that an auction process would not promote efficient outcomes was based on an incorrect assessment of APTPPL's proposal.

APTPPL had proposed queuing requirements that would not, the AER argued, be in accordance with the revenue and pricing principles, and which may not promote the efficient operation and use of the pipeline, or efficient investment in capacity, in accordance with the national gas objective.

The AER's concern that this could be the outcome of APTPPL setting a reserve price for developable capacity auction which may exceed the reference tariff is no longer relevant. APTPPL's current proposal does not incorporate the auctioning of developable capacity.

An auction for the allocation of spare capacity may, the AER contended, result in:

- prospective users being encouraged to bid their perceived maximum willingness to pay, so that the risk of failure to secure capacity is minimised;
- priority being given to bids at tariffs which exceed the reference tariff as a consequence of the ranking of bids by present value of revenue stream; and

- APTPPL earning revenues which are higher than the efficient cost of providing the pipeline service.

These are, of course, outcomes to be expected from an auction of pipeline capacity, at least when limited capacity is available at a time when capacity is required by prospective users. (They may not be the outcomes expected at other times.) The first two of these outcomes are reasons why an auction of spare capacity is likely to be economically efficient. The third is only a concern because, for the AER, regulation per se appears to be of greater importance than the efficient allocation of limited pipeline capacity and the setting of tariffs which support that efficient allocation.

The AER is incorrect in concluding that:

- the efficient provision of pipeline services and the efficient use of the pipeline with respect to the reference service may not be promoted, in accordance with the revenue and pricing principles; and
- efficient investment in, and efficient operation and use of, the pipeline may not be promoted, as required by the NGO.

APTPPL's access arrangement revisions proposal for the RBP submitted in 2011 provided for the auctioning of spare capacity, and its current revisions proposal provides for the auctioning of spare capacity, using a form of first price, sealed bid auction. Such an auction is a mechanism through which prospective users reveal their valuations for pipeline capacity. Certainly, prospective users may be encouraged to bid maximum willingness to pay. But this is precisely the purpose of an auction – to reveal demand, thereby permitting (in the circumstances of the RBP) the allocation of spare pipeline capacity to those users who value it most highly. This outcome – the allocation of resources to those who value them the most – is the essence of economic efficiency. It is the outcome sought, in other contexts (when the numbers of buyers and sellers are large), through organising transactions in competitive markets.

The use of an auction to allocate spare pipeline capacity to those prospective users who value it most highly may result in some of those users offering to pay – and subsequently paying – more that the reference tariff. However, this is not inconsistent with the revenue and pricing principles of section 24 of the NGL. In particular, the service provider is provided with a reasonable opportunity to recover at least the efficient costs of providing reference services, and the service provider is provided with incentives to promote economic efficiency with respect to reference services.

The AER contends that higher tariffs from an auction may distort incentives for pipeline users to undertake investment which would otherwise be efficient. This is not the case. Prospective users will specify, in their bids, tariffs which are consistent with the economics of their investments. The auctioning of spare capacity will ensure that that capacity is allocated to those prospective users with the highest valued uses. The auctioning of pipeline capacity will assist the allocation of resources to economic activity (more broadly than the transportation of gas) in a way which is efficient; it will not distort user incentives for efficient investment.

Since the auction in question is an auction of existing (spare) capacity, the tariffs which it yields – the tariffs the winning bidders offer and subsequently pay – and the revenues from those tariffs have no relevance to decisions about new pipeline investment. The tariffs which winning bidders pay cannot distort incentives which APTPPL may have to carry out efficient pipeline investment. New pipeline investment will be driven, not by the tariffs which users pay for auctioned spare capacity, but by the tariffs which will be paid for developable capacity.

Any prospective user concerned about the tariff it might have to bid to secure capacity in a spare capacity auction can defer its purchase of that capacity until APTPPL develops capacity. At that point, the prospective user can request the reference service at the post-development reference tariff.

In 2012, the AER simply did not examine the economics of the auctioning of spare capacity. It was not concerned with the efficiency issues to which it was directed by the national gas objective. The AER appears to have been concerned only with APTPPL's potential accrual of revenues which might exceed the efficient costs of service provision determined in accordance with the scheme of the NGR, and with the implication that this might "undermine the purpose of regulating revenues". But the costs from which reference tariffs are determined under the access regime of the NGL and the NGR are not marginal costs, and the resulting tariffs have little direct bearing on efficiency.

In holding auctions for spare capacity, APTPPL may, at times, recover more than the efficient costs of service provision determined in accordance with the scheme of the NGR, but that does not undermine the purpose of regulation. The "purpose" to which the AER refers is not the "regulation of revenues"; it is the purpose set out in the national gas objective. The AER has no mandate, under the regime of the NGL and the NGR, to regulate revenues: the AER is to perform or exercise its economic regulatory functions or powers in a manner that will or is likely to contribute to the achievement of the national gas objective (NGL, section 28(1)).

The auctioning of spare capacity in the RBP, as APTPPL proposes, will allocate that capacity to those users who value it most highly. It will thereby promote the efficient operation and use of gas transportation services in the long term interests of consumers of natural gas, as required by the national gas objective.

Industry, the AER advised in 2012, had expressed concern about how revenue from an auction was to be treated. This concern about the treatment of auction revenues is largely irrelevant in the context of the auctioning of spare pipeline capacity. In their bids, prospective users propose tariffs commensurate with their valuations of the spare capacity which is available. A winning bidder pays no more than the tariff which the bidder itself has determined will support its utilisation of that capacity. A bidder is unsuccessful if others propose, in their bids, higher tariffs commensurate with higher valued uses of capacity. Tariffs are driven by prospective user valuations, and lead to the allocation of capacity to those who value it most highly. The tariffs from the auction process support an efficient allocation of spare capacity, and support economic efficiency more broadly. Those outcomes will be distorted by schemes for rebating revenues to users (and will create the potential for gaming at the bidding stage).

Were an auction of spare capacity to lead to APTPPL earning revenues which exceed the costs of service provision determined in accordance with the NGR, the surplus is a consequence of prospective users assessing the economic benefits of utilisation of the capacity which is available at the time of the auction, and being prepared to pay a tariff higher than the reference tariff to secure access to that capacity:

- knowing the reference tariff then prevailing and the costs on which it has been based; and
- knowing that others may be competing with them for access to the same capacity.

The surplus of revenue above cost is a scarcity rent available to the service provider because pipeline capacity is temporarily in limited supply. That scarcity rent will cease to be available if contracts terminate and the quantity of spare capacity becomes sufficient to satisfy all of the requirements of prospective users, or if (as is becoming more frequent) another service provider offers to develop pipeline capacity. It will also cease to be available when APTPPL develops new pipeline capacity. At the time of APTPPL's issue of a notice of auction for spare capacity, some prospective users may not be prepared to pay more than the reference tariff for the spare capacity which is then available, and that may lead to those users deferring (either expressly, or implicitly through unsuccessful bids at the reference tariff) capacity acquisition until additional capacity is developed.

These surpluses of revenue above cost which arise because resources are in limited supply in the short run occur in many markets which are regarded as competitive. They arise because fixed assets cannot be developed instantaneously, and because crops (and sometimes livestock) have "growing periods" which cannot be accelerated. They are not rents associated with the deliberate restriction of output; they are not monopoly rents.

Surpluses of revenue above cost which arise because resources are temporarily in limited supply are a normal part of the workings of dynamic, competitive markets, and are one of the multiple indicators that new investment may be required. These surpluses are not (and should not be) controlled through competition law, or through the application of industry specific regulatory regimes such as the regime of the NGL and the NGR.

In the case of APTPPL's proposed auctioning of limited spare pipeline capacity, proposals to subtract the surpluses from the regulatory asset base, or to mandate their allocation to the financing of pipeline investment, are misguided. They are indicative of failure to consider the economics of the proposed auction process, and its place within the queuing requirements of the RBP Access Arrangement.

Prospective users not treated on a fair and equal basis

Rule 103(3) of the NGR states:

> *Queuing requirements must establish a process or mechanism (or both) for establishing an order of priority between prospective users of spare or developable capacity (or both) in which all prospective users (whether associates of, or unrelated to, the service provider) are treated on a fair and equal basis.*

In 2012, the AER was concerned that the auctioning of spare capacity would result in prospective users not being treated on a "fair and equal basis", as required by Rule 103(3). The reasons for this concern seem to have been:

- APTPPL had discretion to determine the form and amount of financial security required for a bid to be compliant, and could also vary the requirements for security as between prospective users;
- the grounds on which a bid's terms and conditions were deemed capable of immediate acceptance were not specified, and it was not clear to a prospective user how APTPPL would make the assessment of whether a bid was compliant; and
- at the time of bidding, the capacity that may be available to a prospective user was unknown, and prospective users were required to devise and submit terms and conditions relevant to a bid when the basis on which the bid would be assessed as compliant and then ranked was not defined.

These reasons for concern seem to be based on inadequate assessment of APTPPL's proposed queuing requirements.

In the queuing requirements of its earlier (2011) proposal, APTPPL may have had discretion to determine the form and amount of financial security required for a bid to be compliant, and could vary the requirement for security between prospective users. In its current proposal, APTPPL similarly has discretion to determine the form and amount of financial security, and can vary the requirement for security between prospective users, but only in the context of proceeding to a spare capacity auction.

In the auction process which APTPPL is currently proposing:

- prior to the issue of a notice of auction for spare capacity, all prospective users have the same status in respect of spare capacity (each has a current registration of interest which does not assign any priority of access to capacity); and
- the notice of auction for spare capacity must identify the capacity that will be the subject of the auction, and may be accompanied by:
    - information on the form and amount of financial security, and the way in which the requirement for financials security varies between users; and
    - the terms and conditions on which spare capacity may be made available, which may vary according to the categories of services that may be provided using that capacity.

The proposed auction process provides for APTPPL to establish financial security requirements appropriate to contracting for the spare capacity which is available, and for prospective users to be informed of those requirements prior to the submission of bids (at the time of issue of notices of auction for spare capacity). At the time bids are to be submitted, prospective users are similarly placed: they have been treated on a fair an equal basis.

The proposed auction process also provides for APTPPL's informing to provide prospective users about terms and conditions which might be applicable to the spare capacity which is available at the time of issue of notices of auction for spare capacity. Furthermore, the process provides for prospective users consulting with APTPPL on potential alternative terms and conditions prior to bid submission. APTPPL's proposed auction process provides prospective users with the means of ensuring that bids for capacity to be auctioned are compliant, while leaving those users with flexibility to establish terms and conditions specific to their specific requirements. Providing this flexibility is necessary to the efficiency of the auction process: it provides prospective users with the opportunity to submit bids which correctly value their use of auctioned capacity. Prospective users have flexibility in structuring their bids but, at the time bids are to be submitted, they are similarly placed: they have been treated on a fair an equal basis.

One-shot irrevocable bids may not promote efficient pipeline use

One-shot irrevocable bids, the AER maintained, could create an information asymmetry that:

- may not promote the effective negotiation between APTPPL and prospective users that may otherwise encourage more efficient outcomes in accordance with the revenue and pricing principles; and
- may not ensure that the efficient investment in, and the efficient operation and use, of the pipeline is promoted in accordance with the national gas objective.

The AER was specifically concerned that:

- prospective users could not be sure that bids for capacity to be auctioned would be compliant;
- if the capacity requirements of all complying bids did not exceed the capacity offered in a spare capacity auction, each complying bid would be deemed an irrevocable bid request for capacity capable of immediate acceptance;
- bidders seeking access to capacity had no information about what the service provider was willing to accept, or about what other access seekers were offering; and
- industry representatives at a queuing workshop were apprehensive regarding the inability to alter bids once they were accepted, as they could not be sure whether the outcome would be satisfactory for them.

The AER's concerns here, and its view of their implications, may have had some basis in the context of queuing requirements which APTPPL proposed in 2011. However, were they to be advanced now, they would not represent a correct assessment of APTPPL's current proposal.

Terms and conditions, and not quantities and prices, are the matters most likely to determine whether a bid is compliant or not compliant. APTPPL's current queuing requirements therefore specifically provide for:

- APTPPL's informing prospective users on possible terms and conditions applicable to the capacity available for auction at the time of issue of notices of auction for spare capacity; and

- prospective user consultation with the service provider on potential alternative terms and conditions prior to bid submission.

APTPPL's current queuing requirements provide prospective users with a means of ensuring that bids for capacity to be auctioned are compliant.

The efficiency implications of APTPPL's proposed queuing requirements are, in part, a consequence of the use of a first price, sealed bid auction for spare capacity in circumstances where the capacity required to satisfy the demand for pipeline services exceeds the spare capacity which is available. A first price, sealed bid auction is one of the most common and widely used forms of auction. It requires an irrevocable bid which will, in consequence, be capable of immediate acceptance. The efficiency of a first price, sealed bid auction (and of other types of auctions) is lost if bidders know that ex post renegotiation is possible, or if they know what others are bidding.

The efficiency of a first price, sealed bid auction is critically dependent on competition among bidders. If bidders are able to obtain information on what others are bidding, and can then coordinate their bids, the benefit of competition for efficiency is lost. Key regulatory issues where first price, sealed bid auctions are used in publicly administered processes are the prevention of information transfers between bidders, and of explicit or tacit collusion between those bidders in response to the information transfers.[109]

APTPPL's proposed auction for spare capacity provides a means of ensuring the compliance of bids, seeks through the submission of sealed bids to preclude information transfer and collusion among prospective users, and excludes the possibility of renegotiating bids once they have been accepted. Contrary to the AER's contentions, there is no issue of adverse consequences of information asymmetry arising in the context of the proposed auction. Nor (for the reason noted in section 0) is there any issue of compliance with the revenue and pricing principles of section 24 of the NGL. The proposed auctioning of spare capacity has (again, for reasons noted above in section 0) little or no implications for investment – efficient or otherwise – in pipeline capacity. It should, however, (and contrary to the AER's assertion) promote efficient operation and use of the RBP in accordance with the intention of the national gas objective.

[109] See, for example, Paul Klemperer (2004), *Auctions: Theory and Practice*, Princeton: Princeton University Press.

Product definition

Bidders, the AER argued, may face difficulty in forming valuations for an imprecisely defined product, and efficient allocations may therefore be less likely. Effective auctions require the product being auctioned to be specified very tightly, so that prospective users may submit bids which accurately reflect their relative valuations.

APTPPL agrees: an effective auction requires a precise product description so that a bidder can formulate a bid which accurately reflects its valuation of the product being auctioned. This is achieved in APTPPL's proposed process for the auctioning of spare capacity through the requirement that a bidder specifies the terms and condition of access in its bid.

A prospective user can specify in its bid for auctioned spare capacity, terms and conditions which have been designed specifically for its intended use of gas delivered. The prospective user can then place a value on service provision in accordance with those terms and conditions commensurate with the value added by its use of gas.

Alternatively, a prospective user, which does not require terms and conditions designed around a specific intended use of gas, can specify in its bid for auctioned spare capacity the terms and conditions of the Long Term Firm service. Those terms and conditions constitute a precise description of a generic product which is likely to be sought by a significant part of the market, and have been subject to the careful and independent scrutiny of the regulator.

In each case, the prospective user has a precise specification of terms and conditions before it for the purpose of placing a value on access to pipeline capacity. The prospective user has the means of valuing access to spare capacity in a way which is commensurate with the value added by its use of gas. Across all prospective users, this permits the allocation of spare capacity to the highest valued uses: it permits an efficient allocation of spare capacity.

Under APTPPL's proposed queuing requirements incorporating an auction process, prospective users should not face difficulty in forming valuations for an imprecisely defined product, and an efficient allocation of spare capacity should be achieved.

When raising the issue of "product description", the AER adds that the auction process may limit APTPPL's capacity to negotiate terms and conditions that facilitate the efficient operation of the pipeline, and contends that an auction may not improve allocative efficiency compared to the existing first come, first served queuing requirements.

Clearly, the auction process limits APTPPL's ability to negotiate once the auction proceeds. The process is designed to provide the user with flexibility in respect of the service to be provided using the auctioned capacity, and to ensure that the user values access to spare capacity in a way which is commensurate with the value added by its use of gas, as is necessary for efficient capacity allocation. APTPPL would not expect terms and conditions from bona fide bidders which would impair the efficiency of pipeline operation to the extent that a better outcome would be achieved using inefficient first come, first served prioritisation.

Insufficient detail to understand order of priority between and position in the queue

Rule 103(5) requires:

> *Queuing requirements must be sufficiently detailed to enable prospective users:*
>
> *(a) to understand the basis on which an order of priority between them has been, or will be, determined; and*
>
> *(b) if an order of priority has been determined – to determine the prospective user's position in the queue.*

The AER was of the view that there was not sufficient detail in APTPPL's queuing requirements to enable prospective users to understand the basis on which an order of priority between them had been, or will be, determined. Further, if an order of priority had been determined, there was not sufficient detail to allow a prospective user to determine its position in the queue as required under Rule 103(5).

That insufficient detail about the order of priority, and about position in the queue, as the AER had contended, is not the case with APTPPL's current queuing requirements.

Very few prospective users require service provision using less than 2 TJ/d of transmission pipeline capacity. In consequence, the amounts of capacity less than 2 TJ/d are unlikely to become spare, and even if they were, there would be few users seeking access to such small quantities of capacity. If less than 2 TJ/d were to become spare, and there were multiple prospective users for that capacity, they are to be dealt with – in accordance with the queuing requirements – on a first come, first served basis. The basis on which the order of priority is established is clear. In the unlikely event of there being more than one prospective user of less than 2 TJ/d of capacity, APTPPL would advise each prospective user of its position in the queue.

If more than 2 TJ/d of capacity is spare, and APTPPL ascertains that all expressions of interest for services can be satisfied using that capacity, all prospective users are similarly positioned: APTPPL must enter into negotiations with each of them. Effectively, a multi-sever queueing system is established with sufficient "severs" to process all "arrivals" at the same time. Issues of order of priority and position in the queue do not arise.

The case where APTPPL ascertains that all expressions of interest for services cannot be satisfied using the available spare capacity, and initiates an auction for spare capacity, is similar. APTPPL must rank complying bids in order of present value (highest to lowest), and must allocate the spare capacity available to prospective users in the order of their ranked bids. In terms of temporal priority, all prospective users are similarly positioned, and the issue of position in the queue does not arise.

Circumstances in which an auction will be held are not clear

The AER was concerned that the circumstances in which APTPPL would hold an auction were not clear. In particular:

- when all of the pipeline services sought through expressions of interest submitted in response to a spare capacity notice could be satisfied with the available spare capacity, and APTPPL was to negotiate with prospective users:
    - no period was specified within which APTPPL would conduct these negotiations; and

- no process was specified for the allocation of any spare capacity not taken up in these negotiations; and

- when all of the pipeline services sought through expressions of interest submitted in response to a spare capacity notice could not be satisfied with the available spare capacity, and an auction was to be held:
  - there was no specification of how APTPPL would determine whether there was sufficient demand to proceed with an auction; and
  - there was no alternative queuing requirement proposed for the case where the total capacity required to provide pipeline services sought through the expressions of interest exceeded the available spare capacity and APTPPL determined that there was not sufficient demand to proceed with an auction.

APTPPL does not see here any issue of lack of clarity which would support rejection of its proposed queuing requirements.

In accordance with the proposed requirements, if less than 2 TJ/d of capacity becomes spare, APTPPL must make that capacity available to any prospective users within 2 months of their seeking access.

If 2 TJ/d, or more, of capacity becomes spare, APTPPL must provide all prospective users who have submitted registrations of interest in spare capacity with a spare capacity notice which, among other things, calls for expressions of interest in services provided using the available spare capacity. APTPPL must also publish the spare capacity notice in local and national newspapers, giving others the opportunity to submit expressions of interest. The spare capacity notice must state the date by which expressions of interest are to be submitted.

Once the expressions of interest have been submitted, APTPPL must assess whether the services sought by prospective users can be provided with the available spare capacity.

Since APTPPL incurs the costs of providing capacity which is spare, it has strong commercial imperatives to make this assessment quickly and, if sufficient spare capacity is available, to commence negotiations with prospective users and to conclude those negotiations.

If, at the conclusion of these negotiations, there remains spare capacity, then that capacity must be placed on the RBP spare capacity register, in accordance with Rule 111, until such time as there is sufficient prospective user interest to re-initiate the capacity allocation process.

If the services sought in prospective users' expressions of interest cannot be provided with the spare capacity available, APTPPL must initiate (and conclude) a spare capacity auction. There is no complex process of determination of whether there is sufficient demand to proceed, which calls for detailed specification in the queuing requirements. If APTPPL finds that the expressions of interest it has received indicate sufficient demand, then it must then proceed with an auction. APTPPL does not have an option to not so proceed, and no alternative arrangements need to be specified in the queuing requirements.

The circumstances in which an auction is to be held are clear.

Amounts of spare capacity to be offered are unclear

The AER was of the view that the amount of spare capacity which APTPPL would offer on the spare capacity register for the RBP was unclear, as were the amounts of spare capacity to be made available in an open season process, and in an auction. In particular:

- the circumstances in which less than 2 TJ/d of spare capacity would be placed on the spare capacity register were not clear because APTPPL could also make that capacity available in an open season process, or through an auction; and
- APTPPL did not specify how a queue for less than 2 TJ/d would be established and maintained.

APTPPL must, in accordance with Rule 111, place all spare capacity on the RBP spare capacity register.

If the spare capacity on the RBP spare capacity register (which is capacity that has become, or is or is likely to become, available) is at least 2 TJ/d, APTPPL must notify, via a spare capacity notice, each prospective user who has submitted a registration of interest, and must also notify others by publication of the notice in local and national newspapers. The issue and publication of spare capacity notices signal the availability of spare capacity. Were the notice inadvertently not to specify the amount of spare capacity, the amount would be easily obtained from the RBP spare capacity register.

If, then, APTPPL were to commence negotiations with prospective users (as required by the queuing requirements), those prospective users would know that all of the pipeline services sought through expressions of interest submitted in response to the spare capacity notices could be satisfied using the spare capacity which was available, and which was shown on the RBP spare capacity register.

If, after issuing a spare capacity notice, APTPPL were to issue notices of auction for spare capacity, prospective users would know that the capacity shown on the spare capacity register was insufficient to provide all of the pipeline services sought through expressions of interest, and that an auction of that capacity would be held.

The amount of spare capacity to be made available in an open season process, or in an auction, is clear. The amount is the amount shown on the RBP spare capacity register at the time of the open season process or the auction. APTPPL would expect to notify prospective users of that amount in its spare capacity notices and notices of auction for spare capacity.

As noted earlier, very few prospective users require service provision using less than 2 TJ/d of transmission pipeline capacity. In consequence, the amounts of capacity less than 2 TJ/d are unlikely to become spare, and even if they were, there would be few users seeking access to such small quantities of capacity. If less than 2 TJ/d were to become spare, APTPPL would, subject to its obligations under the queuing requirements to make that capacity available to prospective users, seek to add to it additional capacity which was expected to become spare, offering a total spare capacity likely to be attractive to most prospective users. Detailed queuing requirements in respect of isolated "parcels" of spare capacity, in amount less than 2 TJ/d, are simply unnecessary. If less than 2 TJ/d were to become spare at any time, APTPPL's queuing requirements provide a simple scheme for the allocation of that capacity to prospective users.

At all times, the amount of spare capacity available is the amount shown on the RBP spare capacity register. In consequence, the amount of spare capacity which can be made available in an open season process will be known to prospective users at the time of issue of spare capacity notices, and the amount of spare capacity which can be made available in an auction will be known to prospective users at the time of issue of notices of auction of spare capacity. APTPPL's proposed queuing requirements also provide a proportionate scheme for dealing with small (less than 2 TJ/d) amounts of spare capacity. At no time is the amount of spare capacity to be offered unclear.

Allocation of developable capacity by negotiation or auction

The AER advised, in its April 2012 Draft Decision, that the proposed queuing requirements for the RBP allowed APTPPL to determine that developable capacity could be made available, but then did not specify how the service provider was to determine whether to negotiate with prospective users, or to hold an auction to allocate that capacity.

This is no longer an issue. The queuing requirements of APTPPL's current revisions proposal do not include provision for the auctioning of developable capacity.

Inconsistencies in certain clauses

In 2012 the AER was concerned that there were inconsistencies in certain clauses of APTPPL's proposed queuing requirements.

APTPPL is of the view that this is not the case with its current proposal. As noted above, the queuing requirements which now being proposed are those which the ERA has now accepted for the Goldfields Gas Pipeline. They have been subject to careful and independent review by the Western Australian regulator.

A description of general changes to the access arrangement

Section	Change	Reason for change
Various	Replacing Firm Service with Reference Service	Reflects expanded service offerings
Various	Deleting Throughput Charge references	Reflects expanded service offerings and simpler and more transparent charging mechanism
2.1	Addition of Short Term Firm Service as a reference service	Expanded service offering
2.1 and Schedule 8	Attachment of pro-forma Gas Transportation Agreement	Allows Users to view the agreement they will be executing
2.2	Deleted words in 2.2.1	Services will now be offered on a bi-directional basis
2.2	There are two reference services – the Long Term Firm Service and a new Short Term Firm Service	Outlines new service
2.2.2	MDQ	Clarifies that MDQ relates to the Firm Service and that Service Provider will deliver scheduled quantities (subject to the terms and conditions)
4.2 and Schedule 1	Long Term Firm Service Charge and Short Term Firm Service Charge	Sets out amended charging mechanism for the reference services and consequential amendments
4.5.1	Reference Tariff Adjustment Mechanism	Update for new Access Arrangement
6	New queuing requirements	The existing first come, first served queuing requirements are inefficient. This is discussed in section 10 of the submission.

Section	Change	Reason for change
Schedule 2	New definition - Capacity	For purposes of the new queueing requirements.
Schedule 2	Deleted definition – Existing Capacity Queue	No longer used
Schedule 2	Deleted definition – Existing Capacity Queue Deposit	No longer used
Schedule 2	Amended definition – Gross Negligence	Corrects typographical error in previous Access Arrangement
Schedule 2	Deleted definition - Investigation	No longer used
Schedule 2	New definition – Long Term Firm Service	For purposes of expanded service offering
Schedule 2	New definition - Notice of Auction for Spare Capacity	For purposes of the new queueing requirements.
Schedule 2	New definition - Open Season Spare Capacity Closing Date	For purposes of the new queueing requirements.
Schedule 2	Deleted words in Overrun Quantity definition	Correction of definition. Overruns apply to any service (not just firm services) where deliveries exceed scheduled quantities.
Schedule 2	Amended definition – Reference Tariff	For purposes of expanded service offering and amended charging mechanism
Schedule 2	New definition - Short Term Firm Service	For purposes of expanded service offering
Schedule 2	New definitions – Spare Capacity, Spare Capacity Notice and Spare Capacity Register	For purposes of the new queueing requirements.
Schedule 2	Deleted definitions – Throughput Charge and Throughput Tariff	No longer used

B description of changes to standard terms and conditions

Clause	Provision	Reason for provision or modification
Various	Replacing Firm Service with Short Term Firm and Long Term Firm	To reflect expanded service offering
12	Scheduling priorities	Outlines and updates relative scheduling priorities of services
15	Curtailment priorities	Outlines and updates relative curtailment priorities of services
62(c), 63	Deleted	Not applicable. Deleted clause refers to pipeline assets in Western Australia only.

C RIN requirements index

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 1.1	Provide the information required in each *regulatory template* in the Microsoft Excel workbook attached at Appendix A completed in accordance with this *Notice*.	RIN Submission template	RIN Submission template	RIN Submission template
RIN 1.2	1.2 Provide all financial information on a financial year basis and set out: (a) whether the information is actual information, estimated information or forecast information. For information in the nature of a forecast or estimate provide a statement of the basis of the forecast or estimate; and (b) the units of measurement for parameters or values used to derive or infer values; and (c) whether the information is expressed in nominal, real or another basis and include the base year of information where relevant.			
RIN 1.3	1.3 All financial information provided in the regulatory templates must be: (a) on a financial year basis, unless otherwise specified; (b) actual or estimated financial information for the first three years of the current access arrangement period; (c) forecast financial information for year four of the current access arrangement period, to be updated with actual information when that becomes available during the review; (d) forecast information as appropriate for year five of the current access arrangement period; (e) forecast financial information for the next access arrangement period; (f) where required, actual financial information for the previous access arrangement period.			
RIN 1.4	1.4 All expenditure forecasts for the next access arrangement period provided to the AER in response to this RIN must be in real (end of the fifth year of the current access arrangement period) dollars and on a financial year basis, unless specified otherwise.			

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 1.5	Provide any calculations used to convert real to nominal dollars or nominal to real dollars for the purposes of providing the information required under the RIN.			PTRM RAB Rollforward model Forecast Capex Model Forecast Opex Model
RIN 1.6	Provide an explanation should capital and operating expenditure provided in the regulatory templates be materially different to information previously submitted to the AER such as via annually submitted RINs.			No annually submitted RINs
RIN 1.7	In the relevant *regulatory template*, report any change and the materiality of that change where any method of allocation under section 1.6 changes over time.			No annually submitted RINs
RIN 1.8	Where historical information provided in the regulatory templates has previously been reported to the AER: (a) this information must reconcile with the previously provided information; or (b) explain why the information does not reconcile with the previously provided information.			RAB Rollforward Model Section 5.4 Section 6.1.3
RIN 1.9	For each change identified in the response to section 1.8: (a) explain the nature of and the reasons for the variation; and (b) quantify the effect of the variation on the annual Regulatory Information Notice for the relevant regulatory year.			Section 5.4
RIN 1.10(a)	Provide information required in the regulatory templates in accordance with the instructions.			RIN Submission template
RIN 1.10(b)	Provide an index of information outlining the location of the information provided and the in regulatory templates (Attachment A).			This document
RIN 2.1	Provide details of the key drivers behind the demand forecasts.			Chapter 3

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 2.2	Explain and outline the methodology that has been used to support the demand forecasts, including the key assumptions and inputs that have been used and how demand for pipeline services is differentiated.			Chapter 3
RIN 2.3	Explain how the demand forecasts have been used to develop the service provider's capital expenditure and operating expenditure forecasts.			Section 5.7
RIN 2.4	Explain any trends of demand and volumes over the previous access arrangement period and current access arrangement period.			Section 3.3 – 3.7
RIN 3.1	Provide details of the key drivers behind the forecasts of pipeline capacity and utilisation.			Section 3.3 – 3.7
RIN 3.2	Explain and outline the methodology, including key assumptions and inputs used to prepare the forecasts of pipeline capacity and utilisation.			Section 3.3 – 3.7
RIN 3.3	Explain how the pipeline capacity and utilisation forecasts have been used to develop the service provider's capital expenditure and operating expenditure forecasts.			Section 5.7
RIN 3.4	Explain any trends of pipeline capacity and utilisation over the earlier access arrangement period and current access arrangement period.		Section 2.3	Section 3.3 – 3.7
RIN 4.1(a)(i)	Describe and explain the nature of material forecast capital expenditure proposed in each asset class or capital expenditure category.		Section 3.2.1	Section 5.10-5.14
RIN 4.1(a)(ii)	Identify and explain the materiality threshold used to determine material forecast capital expenditure.			section 5.14
RIN 4.1(a)(iii)	Identify the location of the proposed forecast capital expenditure.			Section 5.10-5.14
RIN 4.1(a)(iv)	Provide: (1) relevant internal decision making documents including but not limited to business cases, feasibility studies, forecast demand studies and internal reports and the date of board resolution/management decisions relating to approval of the forecast capital expenditure; and (2) other internal or external documentation or models to justify the forecast conforming capital expenditure.			Attachments 4-1 to 4-4, 5-1 to 5-3 Forecast Capex model

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 4.1(a)(v)	Explain whether the forecast conforming capital expenditure is to be funded by parties other than the asset owner.			Section 6.2
RIN 4.1(a)(vi)	Provide details of contractual agreements with parties where capital contributions are made by users to new capital expenditure pursuant to rule 82.			Attachment 6-1
RIN 4.1(a)(vii)	If Rule 79(2)(a) is relied on to justify new capital expenditure, provide: (1) a quantitative analysis which demonstrates how the capital expenditure is justifiable under Rule 79(2)(a); and (2) an outline of the nature and quantification of the economic value that directly accrues to the service provider, gas producer, users and end users to address Rule 79(3).			Section 5.9.2 Attachment 5-1
RIN 4.1(a)(viii)	If Rule 79(2)(b) is relied on to justify new capital expenditure, provide a quantitative analysis that demonstrates the capital expenditure is justifiable under Rule 79(2)(b).			Section 5.9.2 Attachment 5-1
RIN 4.1(a)(ix)	If Rules 79(2)(c)(i)-79(2)(c)(iii) are relied on to justify new capital expenditure, as relevant: (1) identify the statutory obligation or technical requirement and the relevant authority or body enforcing the obligation or requirement; (2) explain how the forecast capital expenditure satisfies the relevant statutory obligation or technical requirement; and (3) provide supporting technical or other external or internal reports about how the forecast capital expenditure complies with the relevant statutory obligation or technical requirement.			Chapter 5 Attachments 5-1, 5-2 and 5-3
RIN 4.1(a)(x)	If Rule 79(2)(c)(iv) is relied on to justify new capital expenditure: (1) quantify and explain the change in demand for existing services necessitating the new capital expenditure; and (2) provide reports or other information and documentation that supports how the forecast capital expenditure will meet the increase in demand for existing services.			No forecast in this category
RIN 4.1(b)(i)	If the speculative capital expenditure account has increased at a rate different to the rate of return implicit in a			No speculative

Source	Requirement	AA Reference	AAI Reference	Submission
	reference tariff: (1) identify the differences in rates; and (2) explain why.			capex
RIN 4.1(b)(ii)	Identify any mechanism which applies to prevent the service provider from benefiting, through increased revenue, from capital contributions made by a user in the access arrangement period.	Section 3.2		Chapter 10
RIN 4.1(c)(i)	If a mechanism to remove redundant assets is not proposed, explain why with reference to the relevant rules.			mechanism is proposed
RIN 4.1(c)(ii)	Provide an explanation for whether and how APTPPL considers the requirements of s. 79 of the NGR are met for any amounts added to or deducted from the opening capital base: (1) from the speculative capital expenditure account; (2) for the reuse of redundant assets; (3) for redundant assets.		Section 3.2.6	Section 6.1.5 Section 6.2
RIN 4.1(d)(i)	Identify each change to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for the change and provide relevant supporting information.			No changes to standard asset lives proposed
RIN 4.1(d)(ii)	For each proposed new asset class, explain the reason(s) for using these new asset classes and provide relevant supporting information on their proposed standard asset lives.			Section 6.1.1
RIN 4.1(d)(iii)	If existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason(s) for the change and provide relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.			Section 6.1
RIN 4.1(d)(iv)	Describe the method used to calculate the remaining asset lives for existing asset classes as at 1 July 2016 (the start of the forthcoming regulatory control period) and provide supporting calculations.			RAB Rollforward Model Section 6.1
RIN 4.2(a)	Explain and provide details of the proposed method for dealing with taxation and a demonstration of how the taxation is estimated.		Section 8	Section 6.4 Section 9.5

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 4.3(a)	Existing incentive mechanism in the previous access arrangement period For each incentive mechanism which applied in the previous access arrangement period:			No existing incentive mechanism
RIN 4.3(a)(i)	provide an outline of how it operates;			No existing incentive mechanism
RIN 4.3(a)(ii)	explain the increments for efficiency gains and decrements for efficiency losses that have occurred in the previous access arrangement period and the relevant carryover amounts in the current access arrangement period;			No existing incentive mechanism
RIN 4.3(a)(iii)	provide relevant supporting analyses or reports.			No existing incentive mechanism
RIN 4.3(b)	Proposed incentive mechanism in the access arrangement period For each incentive mechanism proposed in the access arrangement period:			No incentive mechanisms proposed
RIN 4.3(b)(i)	provide an outline of how it operates;			No incentive mechanisms proposed
RIN 4.3(b)(ii)	explain its rationale including how it is intended to encourage efficiency of the provision of services and is consistent with the revenue and pricing principles;			No incentive mechanisms proposed
RIN 4.3(b)(iii)	provide relevant supporting analyses or reports.			No incentive mechanisms proposed
RIN 4.4(a)	General information			
RIN 4.4(a)(i)	Provide an outline and explanation of the change in operating expenditure categories between the earlier access arrangement period and the access arrangement period		Section 2.2	Section 8.2
RIN 4.4(a)(ii)	Provide a description and explanation of the nature of material forecast operating expenditure in each operating expenditure category which: (1) outlines changes to the operations of the pipeline from		Section 5	Section 8.1, 8.2 and 8.3

Source	Requirement	AA Reference	AAI Reference	Submission
	the earlier access arrangement period that have resulted in material changes to operating expenditure category and total operating expenditure in the access arrangement period; and (2) identifies the materiality threshold used to determine the material forecast operating expenditure.			
RIN 4.4(b)	Self insurance operating expenditure			
RIN 4.4(b)(i)	Provide the name and a description of the self insurance event.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(ii)	Outline whether the event is in relation to a particular asset or class of assets and, if so, identify those assets.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(iii)	Provide the reasons for self insuring the event. If the event has not previously been self insured, reasons why it is now being proposed and how the risk of the event was previously accommodated in the access arrangement. If a proposed self insurance event was previously insured externally, details of existing or previous insurance policies and reasons why external insurance is not relevant in the access arrangement period.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(iv)	Provide quotes obtained from external insurers for the proposed self insurance event.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(v)	Provide details of how the premiums were calculated, including any underlying assumptions used to derive the premiums.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(vi)	Provide any expert consultant's report relied on by the service provider in deriving the estimates.			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(vii)	Provide, details of existing or previous insurance policies and reasons why external insurance is not relevant in the			AAPTPPL makes no

Source	Requirement	AA Reference	AAI Reference	Submission
	access arrangement period if a proposed self insurance event was previously externally insured.			claim for Self insurance
RIN 4.4(b)(viii)	Provide a resolution (including the date of the resolution) of the service provider's decision making body to self insure the event(s).			AAPTPPL makes no claim for Self insurance
RIN 4.4(b)(ix)	Provide details of the administrative arrangements that: (1) outline how the self insurance risk is to be reported if required under relevant accounting standards in the service provider's audited financial statements. This may include relevant documents that were prepared or submitted for ASIC or other relevant state or territory government authority (2) outline the procedure for notification and information that will be provided to the AER when the self insurance event occurs.			AAPTPPL makes no claim for Self insurance
RIN 4.5	Outsourced forecast operating and capital and expenditure			Attachment 8-1
RIN 4.5(a)	the name of the external party and contract			Attachment 8-1
RIN 4.5(b)	details of how the contract was awarded (for example, by competitive tender)			Attachment 8-1
RIN 4.5(c)	details of fees and charges and a description of the goods or services provided			Attachment 8-1
RIN 4.5(d)	the commencement date and term of the contract			Attachment 8-1
RIN 4.5(e)	reasons why the functions were outsourced			Attachment 8-1
RIN 4.5(f)	details of the relationships with the party or parties named in 4.7(a) and the service provider including if a party to the contract is an associate of any of the service providers of the pipeline; and			Attachment 8-1
RIN 4.5(g)	provide an explanation of the materiality measure used.			Section 8.5

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 4.6(a)	Total revenue allocation			
RIN 4.6(a)(i)	Provide an outline of the nature of the allocation method used to allocate cost pools to reference and other services and provide analysis and information to support this allocation.		Section 10.3	Chapter 9 and 10
RIN 4.6(a)(ii)	If relevant, for rebateable services, provide a description of the mechanism that the service provider will use to apply an appropriate portion of the revenue generated from the sale of rebateable services to price rebates (or refunds) to users of reference services.			N/A
RIN 4.6(b)	Tariffs- transmission pipelines For each reference service and for each user or class of users for a reference service for transmission pipelines:			
RIN 4.6(b)(i)	outline the nature of: (1) costs directly attributable to each reference service (2) other costs that are attributable to reference services (3) where relevant outline the costs directly attributable and other costs attributable for the user or class of users and other users or classes of users.			Section 10.2
RIN 4.6(b)(ii)	explain and provide information about, the cost allocation method outlined in 4.8(a)(i).			Section 10.2
RIN 4.6(c)	Tariff variation mechanism For each tariff variation mechanism:			
RIN 4.6(c)(i)	outline the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism		Section 10.4.1	Section 10.3
RIN 4.6(c)(ii)	outline how the reference tariff mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)).			Section 10.3
RIN 4.6(d)	Cost pass through mechanism For each cost pass through mechanism:			
RIN 4.6(d)(i)	define and describe each cost pass through event;		Section 10.4.3	Section 10.3

Source	Requirement	AA Reference	AAI Reference	Submission
RIN 4.6(d)(ii)	explain how each cost pass through event is relevant to a building block component in Rule 76 and is either foreseen or unforeseen and the costs of the event are uncontrollable and therefore cannot be included in forecasts for total revenue;			Section 10.3
RIN 4.6(d)(iii)	outline how the cost pass through mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)).			Section 10.3
RIN 4.7 (a)	Other information to be provided			
RIN 4.7 (a)(i)	Models and user manuals: include financial models including, but not limited to, tariff, revenue, cost allocation and demand forecasts, along with user manuals that underlie and support the access arrangement proposal and access arrangement information.			PTRM Rab Rollforward Capex forecast Opex Forecast Submission
RIN 4.7 (a)(ii)	(ii) Consultants' reports, including: (1) copies of consultants' or external expert reports relied on to support or justify the access arrangement proposal; and (2) terms of reference for each consultants' or external expert reports relied on identified in 2.7.1(b)(l).			Attachment 3-1 Attachment 5-2
4.8	(a) Maintain and keep information referred to in this Notice in electronic format. (b) Maintain and keep the following information in a manner and form which can be made available for inspection or in a form that can be provided to the AER on request: (i) associate contracts; (ii) contracts for services provided by an external party that contribute in a material way to the provision of pipeline services, and are included in the proposed forecast capital and operating expenditure; (iii) consultants' reports, other than those specifically requested to be provided to the AER in this Notice; and (iv) data, models, internal policies and any other supporting information and documentation, other than			

Source	Requirement	AA Reference	AAI Reference	Submission
	those specifically requested to be provided to the AER in this Notice.			