APA Group

APT Allgas Energy Pty Limited

Access Arrangement Submission

Effective
01 July 2011 – 30 June 2016

Contents

Attachments

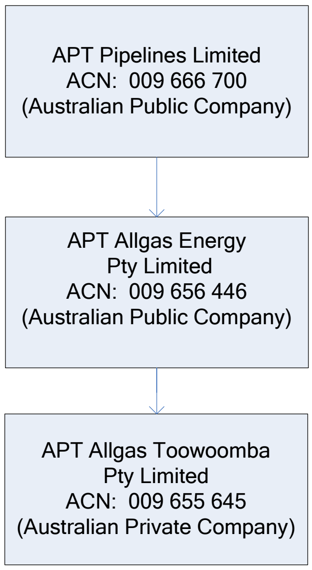
Attachment 1.1	Network Maps
Attachment 3.1	Load Forecast
Attachment 3.1.1	Housing Industry Association of Australia Economics Group, State Outlook – Queensland March quarter 2010
Attachment 3.1.2	APT Allgas Network Development Plan
Attachment 4.1	Asset Management Plan
Attachment 4.2	Capacity Management Plan
Attachment 4.3	Mains Replacement Strategic Plan
Attachment 4.4	Capital Expenditure Performance Review
Attachment 4.5	Parsons Brinckerhoff *Allgas Capex and Opex Review* September 2010
Attachment 4.6	Tendering processes covering the period from 01 July 2007 to 30 June 2010
Attachment 4.7	APA Gas Networks Technical Policy – Economic Criteria for Justification of Capex for Growth of APA Gas Networks
Attachment 4.8	Capex and Opex Business Cases
Attachment 4.9	Tendering Processes covering the period from 01 July 2011 to 30 June 2016 (confidential)
Attachment 6.1	Synergies Economic Consulting (2010), *Estimating a WACC for the Allgas Distribution Network: Key Issues in the Current Environment*
Attachment 7.1	Deloitte Opinion on Approach to Establishing the Tax Asset Base
Attachment 8.1	KPMG, Corporate cost benchmarking – APA Allgas network
Attachment 9.1	Prudent discounts (confidential)

1 Introduction

APT Allgas Energy Pty Limited (APT Allgas) is wholly owned by APT Pipelines Limited. APT Allgas in turn wholly owns APT Allgas Energy Toowoomba Pty Limited. APT Allgas Toowoomba Pty Limited owns the Toowoomba and Oakey gas networks and this Access Arrangement is filed by APT Allgas on behalf of APT Allgas Energy Toowoomba Pty limited.

This structure is shown in Figure 1-1 below.

Figure 1-1 APT Allgas Corporate ownership structure



APT Allgas is both owner and operator of the APT Allgas Network. APT Allgas 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.

APT Allgas' sole business is the ownership and operation of the APT Allgas Network. APT Allgas has no associate contracts in place relevant to the delivery of pipeline services for the APT Allgas Network.

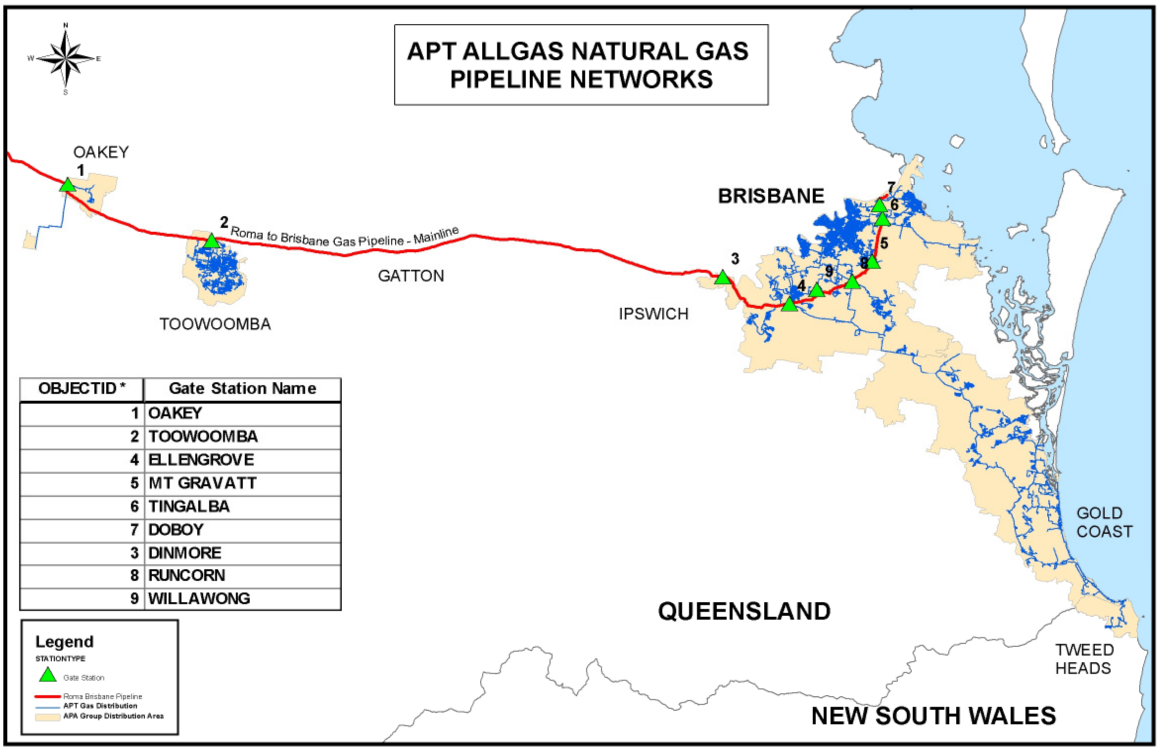
1.1 Network History and Characteristics

The APT Allgas network is separated into three operating regions - the "Brisbane Region" , the "South Coast Region" and the "Western Region". The Brisbane Region covers an area south of the Brisbane River down to the Albert River, whilst the Western region includes Toowoomba and Oakey and the South Coast Region includes the Gold Coast, Tweed Heads and Banora Point in north east NSW. Attachment 1.1 includes overview maps of the various regions showing the extent of the distribution area authorities as well as network mains.

The total system comprises over 2,900 km of distribution mains and a total of 10.5 PJ was delivered to 81,824 End Users on behalf of 3 network Users during FY10. Residential customers accounted for 94.1% of the 81,824 connections and 7.5% of consumption during FY10 with Volume Class business customers accounting for a further 5.8% of connections and 19.3% of consumption. The 102 Demand Class customers accounted for the remaining 73.3% of delivered volume.

The network consists of a number of discreet systems supplied directly off the Roma to Brisbane transmission pipeline (RBP) through gate stations located at Oakey, Toowoomba, Dinmore, Ellengrove, Willawong, Runcorn, Wishart, Tingalpa and Doboy.

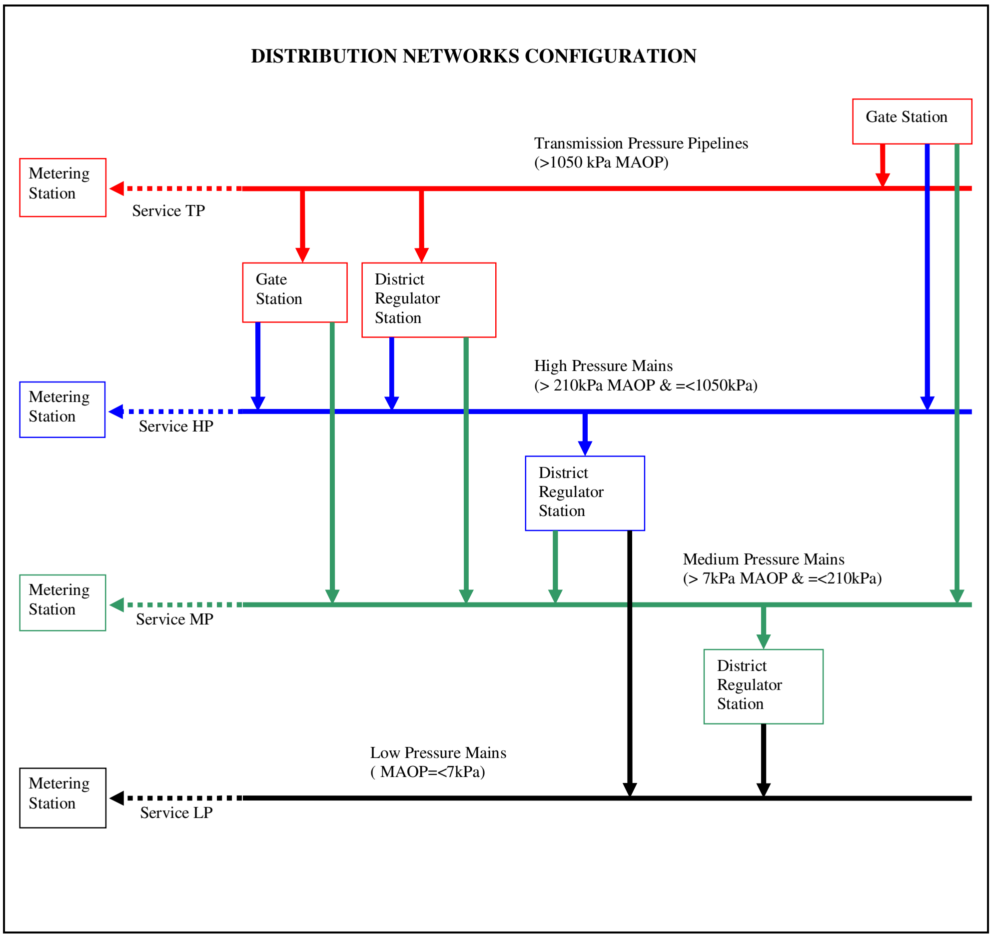
Figure 1-2 APT Allgas Energy Distribution Area



Prior to construction of the RBP towns gas was reticulated in South Brisbane and Toowoomba through networks that date back to the late 19th century. These systems were converted to natural gas immediately following the construction of the RBP in 1969 and have been gradually renewed and expanded to upgrade capacity and supply into new areas.

The network is typically characterised by a transmission or high pressure steel backbone supplying high, medium and low pressure sections of the network through regulator stations as depicted in the following diagram.

Figure 1-3 Typical Network Schematic



Natural gas from the transmission pipeline is metered at the gate stations by turbine or rotary meters with flow computers used to correct for pressure and temperature variations as well as gas composition. Odourisation of the gas is also provided at the gate stations.

The table below summarises the gas mains making up the network by district and pressure regime as at May 2010.

Table 1-1 Network Main Lengths (as at July 2010)

Network main Length (m)	Transmission Pressure	High Pressure	Medium Pressure	Low Pressure	Totals
	>1050 kPa	400-1050 kPa	7-200 kPa	<7 kPa	
Brisbane	254,334	730,557	436,868	294,856	1,716,614
South Coast	157,522	470,584	-	214	628,321
Northern NSW		32,562		270	32,832
Toowoomba	48,294	477,806	2,075	110	528,286
Oakey	6,998	29,136			36,133
Total	**467,148**	**1,740,645**	**438,943**	**295,450**	**2,942,186**

source: Asset Management Plan

Network construction is predominantly polyethylene (PE) (65.5%) and steel (18.0% protected and 4.7% unprotected) with the remainder made up of cast iron (11. 6%) and a small amount of nylon.

1.2 APT Allgas Distribution Network – Brisbane Region

The Brisbane Region is located south of the Brisbane River starting from Dinmore and Springfield in the west to Cleveland in the east, Marsden and Loganlea in the south and Wynnum in the north. The older areas of the Network comprising cast iron and steel mains are supplied through a number of district regulator stations at Ekibin, Norman Park, Wishart, Morningside, Salisbury, Sherwood, Wynnum, South Brisbane, Camp Hill, Hawthorne, Tarragindi and Manly.

The high pressure steel system is connected to high pressure polyethylene (PE), medium pressure and low pressure systems by more than 200 district regulating stations. These district regulator stations serve as a pressure letdown facility from the high pressure into the medium pressure and low pressure systems.

The high pressure Network is comprised of Class 600, 300 and Class 150 steel pipelines.

A high pressure PE system operates in parallel with a high pressure steel system in various parts of Brisbane. The system consists of PE mains ranging from 40 mm to 160 mm in size. The 500 kPa MAOP (Maximum Allowable Operating Pressure) system generally operates at 100 to 200 kPa pressures. Geographically, this system operates through Woodridge, Kingston, Carole Park, Forest Lake, Springfield, Loganlea, Eagleby, Algester, Jindalee, Inala, Sunnybank, Mansfield, Manly, Tingalpa, West End, Woolloongabba and other parts of Brisbane.

The medium and low pressure distribution Network comprises a total of approximately 720 km of pipeline with sizes ranging from 40 mm to 450 mm. The low pressure Network comprises approximately 280 km of steel and cast iron mains in the older districts of Brisbane and Wynnum. Approximately 140 km of these mains are currently located under roadways due to road widening operations over the last several decades.

There are three major medium and low pressure systems in Brisbane, Wynnum, Sherwood and the Older District. The Sherwood system is a medium pressure Network with an MAOP of 35 kPa and the average operating pressure is 15 kPa. The system is comprised of steel, cast iron and PE mains.

This Older District system covers the inner city areas of Woolloongabba, Balmoral, Camp Hill, Coorparoo, Holland Park, Moorooka, Yeronga, Mt Gravatt, Mansfield, and Tarragindi. Reflecting different approaches to network design over many years, the system is a complex network of low and medium pressure mains comprised of steel, cast iron and PE. The average operating pressure is 20 kPa for the medium pressure Network and 1.45 kPa for the low pressure network.

The Wynnum low pressure system covers the suburbs of Wynnum, Manly and Lota. The majority of the mains are steel and cast iron and the system operates between 1.3 and 1.6 kPa pressures.

1.3 APT Allgas Distribution Network – Western Region

The 116 square kilometres of the Allgas Western Region Network consists of 96 square kilometres within the Toowoomba area, bordered by the escarpment in the east to Allen Court in the West, Hermitage Road in the North to Nelson Street in the South.

The remaining 20 square km are located within the Jondaryan Shire Council boundaries at Oakey, with the Network extending from Kearneys Road in the West to; Hamlyn Road in the East, Oakey Aviation Base on Orrs Road to the North and Shannan Street to the South.

A 17.8 km spur main from the Oakey Gate Station extends southward to Purrawanda to supply a single industrial End User.

Both Toowoomba and Oakey Gate Stations are supplied with transmission pressure (5500 to 7000 kPa) gas from the Roma to Brisbane pipeline. The gate station at Oakey is owned and operated by APT Allgas, whereas the Toowoomba Gate Station is operated by APA Group as part of the RBP. At Toowoomba Gate Station, the odourisation facilities and final stage stand-by regulator are owned by APT Allgas.

The Oakey Network is a relatively new system with only three (3) sub-systems and operating pressures:

- high pressure, steel operating at a nominal pressure of 1000 kPa (MAOP 1050 kPa);
- high pressure PE Network operating at a nominal pressure of 140 kPa (MAOP 500 kPa); and
- high Pressure PE Network operating at a nominal pressure of 680 kPa (MAOP 700 kPa).

The Toowoomba network is comprised of the first two types of network described above, and also has a 6.5km class 300 high pressure steel main supplying the Wilsonton industrial estate from the gate station which is currently operating at an MAOP of 1,050 kPa.

1.4 APT Allgas Distribution Network – South Coast Region

The South Coast distribution Network extends from the Albert River in the North to Banora Point (Tweed Heads) in New South Wales in the South. The Network consists of a supply pipeline from the Albert River to Reedy Creek with distribution in the Yatala industrial areas and in the main residential/commercial areas from Runaway Bay to Coolangatta and Tweed Heads. The Network consists of approximately 158 km of high pressure steel mains and 470 km of high pressure PE mains.

The natural gas supply for the South Coast Region is from the Ellen Grove Gate Station (Brisbane). A Metering and pressure reduction facility is installed at Ashmore Rd, Molendinar.

The high pressure Network consists of Class 150, 300 and 600 steel pipelines. The Class 600 and part of the Class 300 mains operate at the same pressure which is fed directly off the RBP at a pressure of nominally 4,600 kPa with the remainder of operating at 2,450 kPa (downstream of Ashmore Road). The Class 150 mains are regulated by district regulators at the connection points to the Class 300 and Class 600 mains. The Class 600 system is basically a supply pipeline running from the Ellen Grove Gate Station south and parallel to the Pacific Highway through to the Ashmore Rd (sub-gate) Station and terminating at Reedy Creek.

1.5 Changes to the Access Arrangement

APT Allgas has substantially retained its AA applying in the 2006-2011 AA period. The pipeline services and reference tariff structures remain unchanged from the 2006-2011 AA period. Terms and conditions of access also remain largely unaltered.

Key changes to the current AA other than those required to move from the National Gas Code to the National Gas Rules and reflect the change in ownership of the network during the access arrangement period are described below.

1.5.1 Revisions submission and commencement dates

Rule 49 requires that a full access arrangement include a revisions submission date and a revisions commencement date. APT Allgas proposes the following revisions submission and commencement dates, consistent with the general rule under Rule 50(1):

- Revisions submissions date: 30 September 2015
- Revisions commencement date: 1 July 2016

1.5.2 Reference services

APT Allgas has amended the conditions for both the Demand Customer Service and the Volume Customer Service to include an MDQ requirement. Customers with an MDQ greater than 50GJ require significant network capacity, and are more appropriately placed on a demand-based tariff, even when their overall volume use may be relatively low. This tariff structure ensures that customers that may have a relatively poor load factor pay the true costs of network capacity to meet their requirements.

1.5.3 Reference tariffs

APT Allgas has transferred some details from section 2 of the AA to Part 4, as these details relate more closely to the structure of the reference tariffs, and rather than the service offered. APT Allgas has included provisions to clarify the tariffs to apply should the revisions commencement date be later than 1 July 2016, and the describe the structure of reference tariffs for each reference service.

Changes to the tariff variation mechanism are discussed in chapter 9 of this submission.

1.5.4 Extension and expansion requirements

APT Allgas has amended its extensions and expansions policy to be consistent with the extensions and expansions requirements recently approved by the AER for the ACT gas distribution network.[1]

The revisions more clearly reflect the separation under the Rules between whether a particular extension or expansion is part of the covered pipeline, and whether the extension or expansion is conforming capital expenditure and added to the capital base. In doing so, APT Allgas has moved (and amended for consistency with the Rules) provisions discussing capital contributions and surcharges to Part 3 of the AA, which describes the determination of total revenue.

1.5.5 Terms and Conditions

As noted above, terms and conditions for the provision of reference services remain largely unchanged from the 2006-2011 AA period. These are set out in summary form in Part 2 of the AA, and in detail in Appendix 3, which forms the Access Agreement with Users. Proposed revisions are set out below.

APT Allgas has clarified and simplified the provisions for calculating when a User's nominated MDQ will be adjusted as a result of MDQ overruns, and formalised arrangements by which Users can request a reduction in MDQ and relevant considerations for APT Allgas when it receive such a request.

The load factor assumption for Demand MDQ has also been changed from 1.1 to 1.3 to better reflect the average overall network load factor based on historical data for the last 5 year period (which was 1.376). Given that interval metering is now required to be installed on all Demand sites, this assumption will only affect a small number of sites as an accurate profile for new connections will be developed over time.

APT Allgas has also revised provisions associated with an increase or decrease of an impost on APT Allgas to be consistent with the revised provisions for cost pass through in clause 4.5 of the AA.

[1] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network, April, Part 7

2 Regulatory Obligations

Compliance with regulatory obligations is a substantial driver of costs for APT Allgas, and underpins a significant proportion of capital and operating expenditure included in the next AA. Compliance with applicable regulatory obligations and requirements is one of the four factors listed under Rule 79(2)(c) for the justification of capital expenditure, and is embedded in the concept of prudent expenditure required for both capital and operating expenditure under the Rules.[2]

Since the last AA was approved, there have been significant changes to both the national economic regulatory framework applying to APT Allgas, but also the nature of the market in Queensland, particularly with the introduction of Full Retail Contestability on 1 July 2007.

These developments, as well as changes to relevant technical and safety regulation, are discussed below, and referenced throughout APT Allgas' submission and associated Asset Management Plan and business cases for individual projects.

2.1 National Regulatory Obligations

2.1.1 National Gas Law and Rules

In July 2008 the new National Gas Law (NGL) and National Gas Rules (NGR) were introduced. These provisions replaced the former National Gas Code, under which the current AA was approved.

While many aspects of the formal National Gas Code are replicated in the new Gas Law and Rules, there are some significant differences in the regimes that are likely to drive costs for APT Allgas in the coming AA period. Key changes in the NGL (compared to the previous Act) include:

- Transfer of the relevant regulator from the Queensland Competition Authority to the AER;
- Establishment of new information gathering powers, allowing the AER to issue binding *Regulatory Information Notices* and *Regulatory Information Orders* on service providers. These powers differ from the previous National Gas Code as they allow the AER to specify the form and content of information to be provided to the AER;
- Extension of regulatory information powers to related providers;
- Extension of compliance monitoring and enforcement powers; and

[2] Rules 79(1) and 91(1)

- Establishment new arrangements for greenfield developments and scope for light regulation of covered pipelines and networks.

Amendments to the NGL in mid-2009 introduced a regulatory framework for the Australian Energy Market Operator (AEMO) to be the single national gas market operator in all states and territories except Western Australia. This change has not had a direct impact on APT Allgas, however it may in the course of the next AA when the Short Term Trading Market is extended and the proposed "Riverview hub" is established.

National Energy Customer Framework

A further phase of national legislation is expected in the coming years called the National Energy customer Framework (NECF). The NECF is intended to replace existing jurisdiction-specific regimes for networks and retail (non-pricing) regulation with a national set out rules.

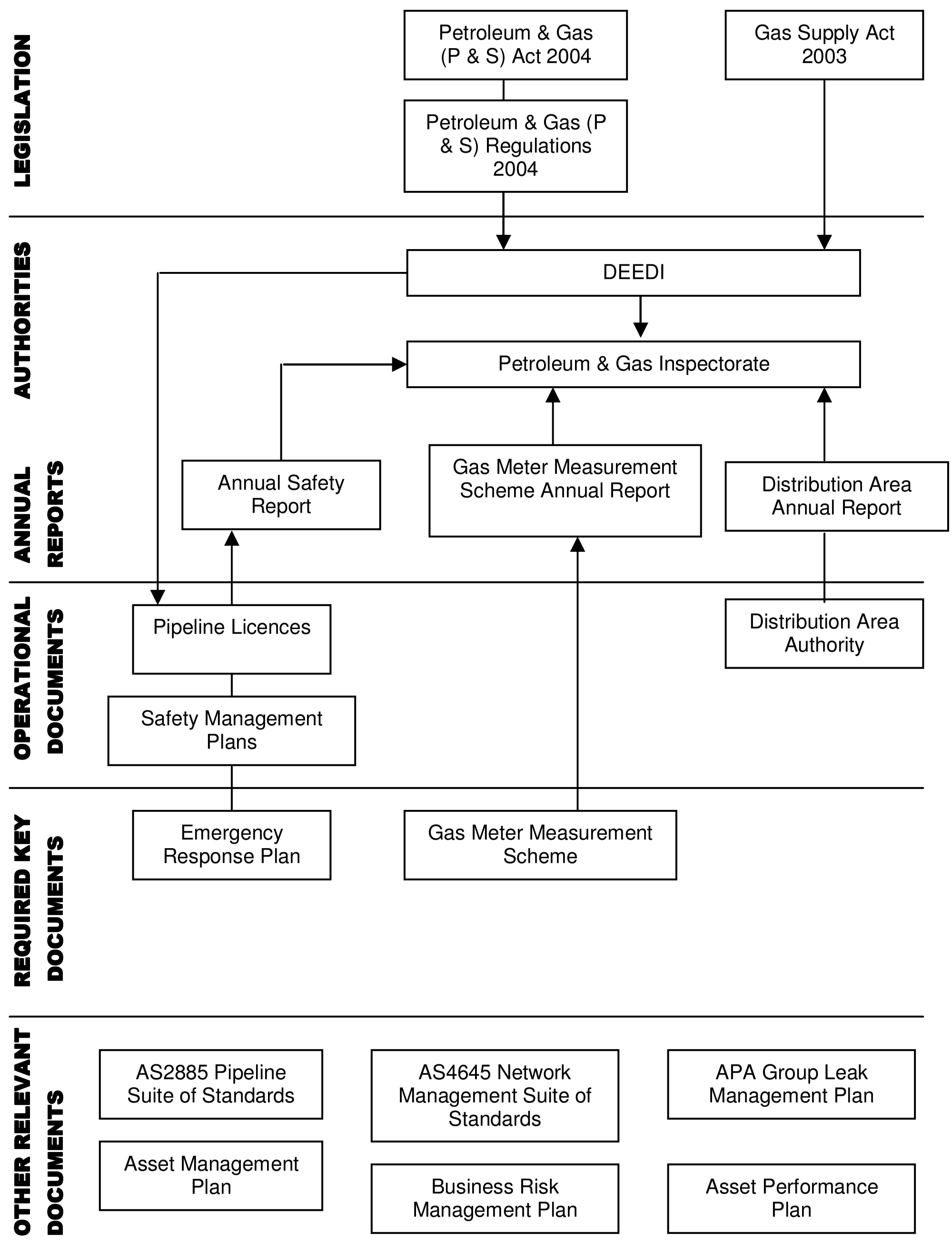
The Queensland Government has released a discussion paper on the implementation of the national framework in Queensland, which canvasses options and timings for the application of the national legislation.[3] As the scope and timing of the implementation of the NECF is not known at the time of this submission, APT Allgas expects that the application of the NECF, including associated administrative and preparation costs incurred by APT Allgas, will be a relevant pass through event under the reference tariff variation mechanisms discussed in chapter 9 of this submission.

2.2 Queensland Regulatory Obligations

A number of state-based legislative instruments govern the operation of APT Allgas in Queensland. These instruments largely relate to non-economic regulation of the gas distribution businesses and safety and technical regulation. Figure 2-1 shows the relationship between these instruments and associated obligations, which are discussed further in the following sections.

[3] Queensland Department of Employment, Economic development and Innovation, *National Energy Customer Framework Queensland Implementation Discussion Paper*, June 2010

Figure 2-1 Key Queensland regulatory obligations



2.2.1 Petroleum and Gas (Production and Safety) Act 2004

The main purpose of this Act is to regulate the petroleum activities in Queensland including the exploration, recovery and transportation of petroleum and fuel gas. For the networks sector, the Act is largely focused on environmental regulation and safety, and includes obligations for network operator in relation to:

- Gas Measurement, including a requirement for a measurement scheme (chapter 8)
- Safety, including details of overall safety requirements and an obligation to develop a Safety Management Plan which details the Safety Management System that must be in place for design, construction, testing, commissioning and maintaining gas assets (chapter 9);
- Emergency response, including an obligation to have an emergency response procedure and 24 hour access for the public to report emergencies;
- Incident reporting;
- Provisions for working with public land authorities; and
- Offences under the Act.

Certain regulations under the Act are also relevant to APT Allgas' operations in Queensland. The Regulations include provisions to:

- Prescribe the quality of gas;
- Require the odourisation of gas;
- Specify mandatory and preferred standards to apply in relation to safety requirements; and
- Specific obligations for incident reporting.

The Regulations also impose an obligation on gas distribution operators to minimise leakage from the network and specify applicable annual fees that must be paid by the distributor.

2.2.2 Gas Supply Act 2003

The *Gas Supply Act 2003* (Qld) regulates non-economic aspects of distribution businesses including connection of customers, licensing and consumer protection.

A distributor cannot distribute gas in Queensland without a relevant distribution authority (licence). The authority imposes obligations on the distributor to:

- take appropriate account of the environmental effects of activities carried out under the distribution authority;
- pay amounts required to be paid under the authority or the Act;
- comply with the Act, the Petroleum and Gas (Production and Safety) Act and all other relevant laws; and
- comply with obligations associated with works in publically controlled places (work directions, guarding etc).

In particular, the Gas Supply Act requires a distributor to respond to applications to connect a premises within 10 business days[4], as well as provide, install and maintain a meter for connected sites[5].

All industry participants are required to inform the Queensland Government, as soon as practicable, of any significant disruption, or event likely to result in a significant disruption, to the supply of processed natural gas. The Queensland Government can also require any industry participant to give in the approved form information in relation to, for example:

- processed natural gas production and estimated future production, by location;
- processed natural gas purchases, by location;
- processed natural gas supplied and future contractual obligations to supply, by location;
- the number of customers in each stated class of customer;
- transportation prices;
- processed natural gas prices for a stated class of customer; and
- estimated reserves of coal seam gas and natural gas.

The Act also includes Retailer of Last Resort (ROLR) provisions, which impose various obligations on APT Allgas. It should be noted that many aspects of this Act have been introduced since the last AA, particular in relation to ROLR and customer transfer, which are part of the introduction of FRC in Queensland in July 2007.

[4] Gas Supply Act s. 104
[5] Gas Supply Act s. 126

2.2.3 APT Allgas area distribution authorisation (Queensland)

APT Allgas' area distribution authorisation, in its current form, was issued on 27 September 2004 (for Energex), and has been revised and amended on a number of occasions since this time, including to transfer to authorisation to APT Allgas.[6]

The authorisation includes an obligation on APT Allgas to prepare and submit an annual report to the relevant minister by 31 October each year, and to pay distribution authority fees as required under the Gas Supply Regulations.

2.2.4 Workplace Health and Safety Act 1995

The Workplace Health and Safety Act 1995 (Qld) establishes a "duty of care" for employers and employees to provide a safe place of work, safe system of work, safe plant and machinery and competent staff.

2.2.5 Environmental Protection Act 1994

The *Environmental Protection Act 1994* (Qld) applies to activities impacting the air, land or water, and covers contamination, noise and waste. The Act applies to APT Allgas' operations in both the construction and operation of its network, including the network directly, as well as associated depots, sites and other facilities.

APT Allgas use the APIA Code of Environmental Practice for Onshore Pipelines as guidance in meeting its obligations under this Act and associated Regulations.

2.2.6 Applicable Regulations, Codes and Standards

The following Regulations apply to APT Allgas under relevant Acts, and provide prescriptive standards for each of the relevant Acts:

- Petroleum and Gas (Production and Safety) Regulation 2004
- National Gas (Queensland) Regulation 2008
- Gas Supply Regulation 2007
- Workplace Health and Safety Regulation 2008
- Environmental Protection Regulation 1998

The following are supplementary Acts and Regulations that APT Allgas must work under:

[6] Queensland Government Area Distribution Authority No. DA-A-009 issued to APT Allgas Energy Pty Limited ACN 009 656 446, accessed at http://www.dme.qld.gov.au/Energy/licensing_1.cfm

- Disaster Management Act 2003
- Clean Energy Act 2008
- Integrated Planning Regulation 1998
- Energy Ombudsman Act 2006
- Energy Ombudsman Regulation 2007
- Native Title (Queensland) Act 1993

2.3 New South Wales Regulatory Obligations

As part of the APT Allgas network is in NSW, APT Allgas must also comply with relevant NSW legislation with respect to those parts of the network. The NSW legislation covers similar areas to the corresponding Queensland obligations, however there are significant differences that increase the complexity of APT Allgas' compliance systems, and associated compliance costs. Relevant instruments are described in the following sections.

2.3.1 Gas Supply Act 1996

The *Gas Supply Act 1996* (NSW) regulates non-economic aspects of distribution businesses including licensing and consumer protection.

Similar to the corresponding Queensland act, the NSW *Gas Supply Act* requires distributors to hold a reticulators authorisation before it can distribute gas in NSW. The authorisation is enforced by the Independent Pricing and Regulatory Tribunal (IPART), which has the power to impose monetary penalties on authorisation holders for non-compliance with the authorisation, and the responsible minister can cancel an authorisation. Annual authorisation fees apply.

2.3.2 New South Wales Gas Regulations

New South Wales has several gas regulations that detail the requirements for each aspect of a gas distribution network. Each regulation (with the exception of the last) sets out materials, design, construction, installation, testing and maintenance requirements for safe management of each element (asset) of the gas distribution network operating at less or equal to 1050 kPa, throughout the life cycle of all elements of that network. The regulations are:

- Gas Supply (Safety and Network Management) Regulation 2008
- Gas Supply (Gas Meters) Regulation 2002 (administered by the Department of Fair Trading)

- Gas Supply (Natural Gas Retail Competition) Regulation 2001

2.3.3 Other New South Wales legislation

Other NSW instruments that have an impact upon APT Allgas' network operations inlcude:

- National Gas (NSW) Act 2008 No 31
- Pipelines Act 1967 No 90
- Pipelines Regulation 2005
- Independent Pricing and Regulatory Tribunal Act 1992 No 39
- Fair Trading Regulation 2007
- Home Building Act 1989 No.147
- Home Building Regulation 2004
- Environmental Planning and Assessment Act 1979 No 203
- Environmental Planning and Assessment Regulation 2000
- Protection of the Environment Operations Act 1997 No 156
- Protection of the Environment Operations (Clean Air) Regulation 2002
- Energy and Utilities Administration Act 1987 No 103
- Industrial Relations Act 1996 No 17
- Occupational Health and Safety Act 2000 No 40
- Occupation Health and Safety Regulation 2201

2.4 Australian Standards

The following Australian Standards are referred to in relevant Queensland instruments as mandatory or preferred standards and are therefore considered to be the primary codes of practice applicable to APT Allgas activities:

- AS 4645.1:2008 Gas Distribution Networks – Network Management

This standard specifies the requirements for safe management of a gas distribution network operating at less or equal to 1050 kPa, throughout the life cycle of all elements of that network. This standard applies to all assets between the City Gate Station and consumer meter outlet connections.

- AS 4645.2:2008 Gas Distribution Networks – Steel Pipe Systems

This standard specifies materials, design, construction, installation, testing and maintenance requirements for steel pipe construction operating at less or equal to 1050 kPa.

- AS 4645.3:2008 Gas Distribution Networks – Plastic Pipe Systems

This standard specifies materials, design, construction, installation, testing and maintenance requirements for below ground plastic gas distribution networks with a MAOP of 700 kPa.

The following suite of standards deal with the operation of steel gas pipelines above 1050 kPa:

- AS 2885.0–2008 Pipelines Gas and Liquid Petroleum – General Requirements
- AS 2885.1–2007 and Amendment 1:2009 Pipelines Gas and Liquid Petroleum Design and Construction
- AS 2885.2–2007 Pipelines Gas and Liquid Petroleum – Welding
- AS 2885.3–2001 Pipelines Gas and Liquid Petroleum – Operations and Maintenance
- AS 2885.5–2002 Pipelines Gas and Liquid Petroleum – Field Pressure Testing

The following standards are used to support the above standards in operating a gas distribution network:

- AS 4041-2006 Pressure Piping
- AS/NZS 2430-2004 Classification of Hazardous Areas
- AS/NZS 4130-2009 Polyethylene (PE) Pipes for pressure applications
- AS/NZS 4944-2006 Gas Meters – In Service Compliance Testing
- AS ISO 13443-2007 Natural Gas – Standard Reference Conditions
- AS 4564-2005 Specification for general purpose natural gas

There is also an assortment of supplementary Australian Standards relevant to setting codes of practice, material standards, specifications, procedures, etc that are not listed here as principle standards, but which do influence APT Allgas' operational activities.

3 Network load and demand

This section briefly outlines the APT Allgas approach to load forecasting, and presents summary results. The complete load forecast is included as Attachment 3.1.

3.1 Forecasting methodology

Customer numbers and consumption have been forecast for both the Volume and Demand classes using two methodologies in progressive stages:

- Mapping historical customer numbers and consumption by year, to identify growth trends. This historical data forms the basis for further analysis.
- Investigating key indicators of growth such as industry forecasts, emerging market trends, government, regulatory and policy changes and APA Group initiatives; and applying this knowledge to the base forecast above.

3.1.1 Mapping trends in customer numbers and consumption from historical data

3.1.1.1 Volume Class customer numbers

The FY10 actual new network connections have been used as the foundation for the upcoming AA period customer number forecast for Residential customers in the Volume Class.

Total customer connections were split into customer segments (New Homes, New Units, Existing Homes, Business) to enable analyses of each individual customer market. These investigations have been used to forecast APT Allgas network demand for the coming AA period for each customer segment, combining to give the total.

New dwellings were split into new homes and new units using the Housing Institute of Australia (HIA) dwelling start forecasts. It is reasonable to assume that new dwelling start trends in natural gas reticulated areas will follow new dwelling start trends for the entire market.

This FY11 forecast was used as the basis for the upcoming AA period forecast, with further development using analysis of the market context for Residential customer segments, as per Section 3.1.2 below.

3.1.1.2 *Volume Class consumption*

An analysis of historical trends was used to form the base forecast for Volume Class customer consumption, with further development using analysis of the market context, as per Section 3.1.2 below.

3.1.1.3 *Demand Class customer numbers*

Analysis of historical information has been important in forecasting network performance for the Demand Class in the upcoming AA period.

The forecast assumes that connection rates will continue in line with historical averages and that the existing customer base will remain unchanged. These assumptions have been derived from analysis of historical information and discussions with large end users and retailers operating in this market.

3.1.1.4 *Demand Class customer consumption*

Demand Class customer consumption forecasts for the 2011-16 AA period have been developed through the following process:

- Review of historical demand
- Holding discussions with largest users
- Analysis of industry group trends

3.1.2 Applying key indicators of growth to the base forecast above

Investigating key indicators of growth such as industry forecasts, emerging market trends, Government regulatory and policy changes and APA Group initiatives; and applying this knowledge to the base forecast above. Details of these indicators are discussed further in Section 3.2. Key drivers for Volume customers and Section 3.3 Key drivers for Demand customers.

3.2 *Key drivers for the Volume Class*

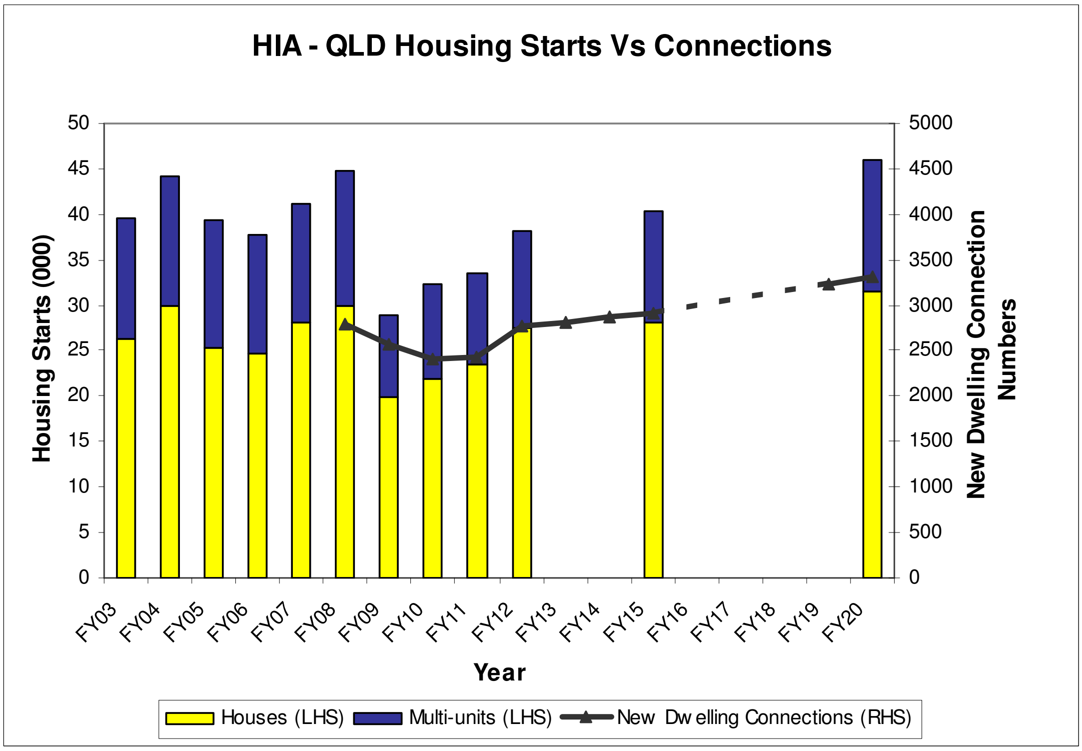
The key drivers for network performance in the Volume Class are growth in customer numbers and average consumption per customer. Factors influencing these drivers are discussed in this section, and include market trends with regard to competition from electric appliances, solar and heat pump hot water; Government initiatives regarding environmental sustainability; water and energy conservation; and the emergence of new technologies.

3.2.1 Growth in customer numbers

3.2.1.1 New dwelling starts

Given that new construction in natural gas reticulated areas creates a market for new network connections, new dwelling start forecast data provided by the Housing Industry Association (HIA) was applied to forecast the growth of natural gas network connections for Volume Class Residential, new dwellings, as shown in Figure 3-1 below.

Figure 3-1



3.2.1.2 Competition from electric appliances, solar and heat pump hot water

Electric appliances can be used as an alternative for all natural gas applications, such as water heating, cooking, heating, etc. Electricity is essential to support current standards of living, and is automatically connected to every new home, ready to power any electric appliance.

Hot water systems are the largest gas consuming appliances available for Queensland residential use and as such, the penetration of natural gas into the hot water market, relative to other fuels, is particularly important. Historical trends show a decline in use of electricity for water heating in Queensland. However, while gas was the clear 2nd preference earlier this decade, solar has overtaken natural gas in recent years. Heat pump hot water systems are also an emerging competitor, as they are quick and easy to install, and can be connected to the existing electricity supply.

3.2.1.3 Government initiatives regarding environmental sustainability

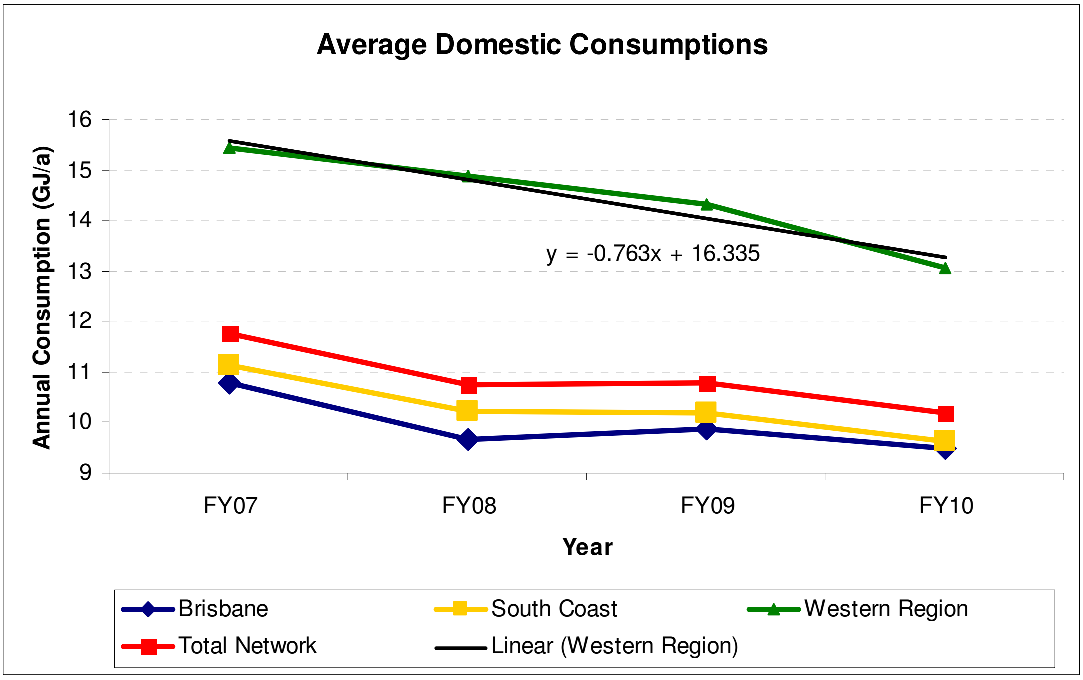
A potential contributing factor to new connection growth for Volume Class Residential existing dwellings is the new Queensland Government legislation banning the installation of electric resistance hot water systems in existing homes that can have a natural gas service and meter installed on the property boundary at no cost from the distributor to the home owner, when the existing hot water system is replaced. As discussed more fully in Attachment 3.1, while APT Allgas forecasts a 0% market share of emergency replacement of failed electric resistance hot water systems, Network Development activities are being undertaken to maximise market share of voluntary replacement of existing electric resistance hot water systems, including improved connection times and more efficient connection processes.

Solar and heat pump hot water systems are also eligible for Government rebates and financial incentives such as Renewable Energy Certificates, the Federal Hot Water Rebate and the Queensland Government Solar Hot Water Rebate, all of which combine to significantly reduce the initial cost of purchasing a solar or heat pump hot water system. Natural gas hot water systems are not eligible for any of these rebates or incentives.

3.2.2 Average customer consumption

Average domestic customer consumption is in decline, as shown in Figure 3-2 below.

Figure 3-2 Average domestic consumption per customer, by region



The decline in consumption for FY07 to FY08 is due primarily to the effect of drought on hot water usage and in turn gas consumption through the introduction of water efficiency measures to combat the drought, such as water restrictions and the implementation of water efficient devices such as shower heads and washing machines.

Whilst water restrictions have been relaxed slightly, consumption trends remain low and the effects of changes to water efficient devices will result in lower levels continuing into the future. Water restrictions in the Western Region (Toowoomba and Oakey) remain at high levels as these areas still have extremely low dam levels.

Consumption in has also been affected by the loss of market share in the home heating market to reverse cycle air conditioners. This is significant, as a reverse cycle air conditioner can meet all the home heating needs of a typical Queensland household without a requirement for the customer to invest in a separate (gas consuming) space heating appliance.

3.3 Key drivers for the Demand Class

The key drivers for network performance in the Demand Class are growth in customer numbers and average consumption per customer.

3.3.1 Growth in customer numbers

Customer number growth is affected by economic drivers as the decision to replace existing equipment is subject to cost and Return on Investment (ROI) assessment. Economic conditions impact business start ups and closures, which also drive customer number growth on the network.

Demand Class forecasts for the 2011-16 AA period have been developed via a review of historical demand, holding discussions with the largest users, and an analysis of industry group trends.

The forecast for Demand class customer numbers assumes that connection rates will continue in line with historical averages and that the existing customer base will remain unchanged. These assumptions have been derived from analysis of historical information and discussions with large end users and retailers operating in this market.

3.3.2 Customer consumption

A survey of 25 of the top Demand Class customers was conducted either directly with the customer or with the responsible retailer.

In general the indication of future loads was ‘business as usual’ with mainly slight increases forecast. No significant issues were identified through this process and as such future projections based on recent historical trends was considered prudent.

Historical trends over the last three years indicate steady consumption over the current AA period and this is assumed to continue with small incremental growth from increases in customer numbers which are assumed to be spread over Demand zones 1 to 4.

3.4 Actual & Estimated customer numbers

The table below shows total customer numbers for the network, per year.

Table 3-1 Total customer numbers for the network, per year.

	FY07	FY08	FY09	FY10	FY11 (f)	FY12 (f)	FY13 (f)	FY14 (f)	FY15 (f)	FY16 (f)
Volume Class	73,656	76,522	79,483	81,722	84,290	87,169	90,119	93,143	96,243	99,441
Demand Class	108	109	114	102	101	102	103	104	105	106
TOTAL	**73,764**	**76,631**	**79,597**	**81,824**	**84,391**	**87,271**	**90,222**	**93,247**	**96,348**	**99,547**

3.5 Actual & Estimated volumes

The table below shows total network consumption, TJ per year.

Table 3-2 Total network consumption, TJ per year

	FY07	FY08	FY09	FY10	FY11 (f)	FY12 (f)	FY13 (f)	FY14 (f)	FY15 (f)	FY16 (f)
Volume Class	2,896	2,920	2,912	2,800	2,844	2,908	2,984	3,062	3,154	3,249
Demand Class	7,154	7,679	7,565	7,666	6,955	6,970	6,985	7,000	7,015	7,030
TOTAL	**10,050**	**10,599**	**10,477**	**10,466**	**9,799**	**9,878**	**9,969**	**10,062**	**10,169**	**10,278**

3.6 Network Development Summary

The purpose of Network Development activity is to maximise utilisation of the natural gas networks by increasing customer numbers and average customer consumption, thereby lowering the unit cost of delivered natural gas to the customer by spreading fixed network operation costs over a larger customer base.

Network Development consists of Customer Service and Representation (labour costs) and Marketing and promotion programs. Labour costs include operation of the Natural Gas Hotline and all tasks required to coordinate and process new network connection work orders and maintain relationships with key customers and industry groups. This activity type is therefore essential to network operation and growth. Key Marketing and promotion programs include advertising, direct communication and events based activities targeting specific customer segments crucial to long-term network growth; and performance based incentives designed to boost network connection numbers at strategic times.

Given the long-term objectives of Network Development activities, the impact on network performance is expected to be reflected in business as usual network growth, with no significant measurable increases in the short term.

4 Capital expenditure

This section provides assessments of capital expenditure projects completed during the earlier access arrangement period and justification for the forecast capital expenditure projects.

APT Allgas classifies system capital expenditure based on purpose in categories as follows:

- Customer initiated capital expenditure - is required to meet growth in customer numbers and demand;
- Network augmentation capital expenditure - is required to maintain capacity to meet current customer demand and to provide additional capacity to meet future customer demand;
- Network renewal capital expenditure - is necessary for renewal and replacement of ageing network assets and compliance requirements relating to safety and reliability.

Non-system capital expenditure is related to IT systems and softwares, motor vehicles and plant and equipment which are not part of the distribution network.

4.1 Network strategic planning

The Strategic Planning Process[7] integrates knowledge of existing and future customer requirements, operational requirements and risk management options to be able to optimise performance of gas distribution systems.

The key role of network strategic planning is to predict and analyse all factors that can influence design, construction, maintenance and operation of gas distribution systems over a long period of time and to plan system development to be able to cost-effectively, efficiently and reliably deliver gas to the existing and potential new users.

Key sub-processes are:

- Analyse current distribution systems performance
- Forecast future distribution system performance
- Develop Risk Management Plan[8]

[7] Capacity Management Strategic Plan – Appendix 6 - Strategic Capital Planning Process (Attachment 4.2)

- Review and upgrade Asset Management Plans
- Monitor implementation of Asset Management Plans

The purpose of analysing the distribution system's performance is to identify current critical operational and asset related risks and performance improvement opportunities including network capability to cost-effectively, efficiently and reliably delivery gas to the existing users.

The forecasting of future distribution system performance is used to identify potential future critical operational and asset related risks and performance improvement opportunities to be able to analyse network capability to cost-effectively, efficiently and reliably deliver gas to all customers in the future.

The purpose of the development of the Risk Management Plan is to achieve a more confident and rigorous basis for decision making and proactive management of identified network operational threats and improvement opportunities. The requirements of this process applies to analysing the identified risks by determining consequences, likelihoods and related risk levels in accordance with relevant Australian Standards and APA Group policies and recommending risk management options to optimise gas distribution network's current and future performance. Selecting the most appropriate risk treatment option is a complex process involving optimisation of the total outcome from all proposed projects and improvements including trade-offs between different risk treatment categories and balancing the costs and related benefits.

The review and upgrade of the Asset Management Plan[9] and other supporting plans on outcomes of the Risk Management Plan identifies optimal capital investment, maintenance and operational strategies necessary for development and the operation of a secure, reliable, safe, cost effective and environmentally responsible gas distribution network that satisfies the evolving needs of all classes of customers and the growth requirements of the asset owner.

Effective asset management requires continuous monitoring implementation of Asset Management Plans and taking corrective actions if required to ensure that the network is extended, operated and maintained to the required levels of safety, reliability and sustainability with processes continuously improved and optimised.

4.1.1 Asset Management Plan

The Asset Management Plan (AMP) endeavours to optimise all interventions on the network by continuously monitoring the performance of the network and seeking to achieve increasing levels of safety and operational efficiency over the entire lifetime of the network assets. The AMP provides a consolidated view of a number of

[8] Capacity Management Strategic Plan – Appendix 7 - Risk Management Plan (Attachment 4.2)

[9] Asset Management Plan, See Attachment 4.1

technical and operational plans and how these are used to drive asset management strategies and expenditure to ensure safe, reliable and sustainable supply of gas in line with:

- Legislative obligations
- Effective risk management
- Financial business parameters
- Lowest lifecycle costs
- Extraction of maximum value from assets

The AMP is underpinned by the following associated plans:

- Business Risk Management Plan
- Safety Management Plan
- Network Load Growth Forecast Plan
- Capacity Management Strategic Plan
- Mains Replacement Strategic Plan
- Meter Measurement Scheme Version 6 for the APT Allgas Networks

Key issues and actions from these plans have been summarised and detailed in the AMP.

4.1.2 Capacity Management Strategic Plan

The network Capacity Management Strategic Plan[10] integrates knowledge of existing and future customer requirements, operational requirements and risk management options to be able to optimise performance of gas distribution systems.

This document includes an overview of the distribution networks covered by this plan, and the protocols associated with network capacity management, load forecast, performance review and network augmentation requirements.

The objective of the gas distribution networks Capacity Management Strategic Plan is to document:

- The current capacity performance of the gas distribution networks

[10] Capacity Management Strategic Plan, See Attachment 4.2

- The basis for maintaining capacity within the gas distribution networks
- The scope, timing and budget estimates of augmentation projects required to cost-effectively sustain network growth and maintain a safe and reliable supply of gas to consumers

4.1.3 Mains Replacement Strategic Plan

The gas distribution network Mains Replacement Strategic Plan[11] provides the basis and justification for a mains replacement programme.

This replacement plan focuses on optimising the use of available replacement capital expenditure funds by targeting replacement of mains that:

- Present a high risk to the public and or maintenance personnel
- Have insufficient capacity to meet current and future consumer demands
- Incur high maintenance and operating costs

This document outlines the objective of maintaining integrity of the network and the capacity to meet current customer demands, reducing maintenance and operational risks and costs within the old low and medium pressure distribution networks. As part of this mains replacement plan the forecast safety and economic benefits are closely monitored to substantiate and justify the proposed mains replacement costs.

The output of the plan is the forecast mains replacement capital expenditure which focuses primarily on retiring the old cast iron and unprotected steel mains from the network.

4.2 Capital expenditure governance process

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

Capital Expenditure Budget is developed as outcome from Strategic Capital Planning Process and includes concept plans, implementation schedule for major network augmentation, renewal and customer initiated projects and high level cost estimates for all proposed capital expenditure projects.

Routine capital expenditure works are governed by approved Capital Expenditure Budget. The capital expenditure approval is required for all other capital projects and includes relevant information like identified needs, risk assessment, options

[11] Mains Replacement Strategic Plan, See Attachment 4.3

considered, cost estimation, project justification and recommendation. The proposed capital expenditure projects are submitted for approval as per the Delegation of Authority Policy requirements.

The actual costs are reviewed against approved budget costs for major projects and reported if required (variance of more than 10% to approved budget).

Performance of total actual capital expenditure is reviewed against approved Capital Expenditure Budget on monthly basis and corrective actions implemented if required.

4.3 Distribution network capacity and utilisation

Load growth forecasting is a critical input to network capacity modelling. It is the basis for determining where and how networks are augmented to meet future demand.

For operational, network design and planning purposes the demand forecasts are augmented with location specific information sourced via network marketing so that intra-network constraints can be identified and future capital expenditure requirements optimised.

The future load profiles are calculated by adding expected additional hourly loads (multiplied by average diversity factors) for domestic, commercial and industrial customers to the existing load profiles. The currently known, potential large industrial customer loads are added individually. The hourly load forecast is critical for development of strategies for network renewal, augmentation and extension projects.

4.3.1 Gate stations and pipelines

All existing gate stations and pipelines meet current customer load demands. Based on new customer connection forecasts it is estimated that there are potential future capacity problems as follows:

- Tingalpa Gate Station is in the process of an upgrade to be able to meet future customer demands and to supply all customers connected currently to Doboy Gate Station.
- The Cleveland Pipeline will not have sufficient capacity to meet potential domestic and commercial customer demands in the next 3 to 5 years
- The Brisbane to Gold Coast Pipeline supplying the South Coast Region has limited spare capacity and it is estimated that in winter 2016 it will not be able to meet all customer demands

4.3.2 High Pressure Steel Networks

Most of the existing gate stations and district regulator stations supplying high pressure steel networks have sufficient capacities to meet current customer demands. There are potential future capacity problems as follows:

- The high pressure steel mains supplying Surfers Paradise, Broadbeach, Rangeville, East Toowoomba, Oxley, Seventeen Mile Rocks, Sinnamon Park, Jindalee, Morningside, Balmoral, Bulimba, Hawthorne, Norman Park Acacia Ridge, Coopers Plains, Salisbury, Tarragindi, Moorooka and Greenslopes have very limited spare capacity to meet new customer demands.

- The high pressure steel mains supplying Camp Hill, Coorparoo, Woolloongabba, East Brisbane, Kangaroo Point, South Brisbane and West End may be not able to meet potential future very large additional commercial and industrial customer demand.

4.3.3 High Pressure Polyethylene Networks

Most of the existing district regulator stations and related high pressure polyethylene networks have sufficient capacities to meet current customer demands. However:

- High pressure polyethylene mains in Oakey, supplying single demand customers, have no spare capacity.

- High pressure polyethylene networks in Surfers Paradise, Broadbeach, Rangeville and East Toowoomba have very limited spare capacities to meet new customer demands.

4.3.4 Medium and Low Pressure Networks

Urban redevelopment throughout the suburbs of Brisbane is creating capacity problems in the low and medium pressure networks. These have generally been traced to either water ingress, the use of high demand appliances or “organic growth” in areas where housing density has been increased because of urban consolidation developments.

4.4 Capital expenditure during the earlier access arrangement period

4.4.1 Comparison of QCA final approval[12] and outturn capital expenditure 2006/07 to 20010/11

APT Allgas capital expenditure has been below the level assumed in the QCA's 2006 Final Approval, with actual capital expenditure over the period of approximately $115.5m, which is $28.0m less than the amount of capital expenditure approved by QCA. Table 4-1 shows a comparison of QCA approved and actual capital expenditures for this period with forecast for the 2010/11 Financial Year.

An overall analysis of APT Allgas' capital expenditure performance for the current access arrangement period is presented in Capital Expenditure Performance Review[13] and supported with critical information obtained from Capital Expenditure Plan.

Ownership of the Allgas Distribution Network was transferred from Energex to APA Group on 1 November 2006. The transition period required an adjustment to the new work environment including establishment of new supporting systems, review of existing processes, policies, work procedures and organisation structure to be able to optimise overall performance in accordance with the business targets of APA Group.

APT Allgas considers that all its actual capital expenditure in the current access arrangement period satisfies the conforming capital expenditure criteria test under Rule 79. This view is supported by the Parsons Brinckerhoff Allgas CAPEX and OPEX Review[14], which concludes that APT Allgas' actual capital expenditure in current access arrangement period is compliant.

[12] Allgas QCA Final Approval AA June 2006

[13] Capital Expenditure Performance Review Attachment 4.4

[14] Parsons Brinckerhoff, Allgas CAPEX and OPEX Review, See Attachment 4.5

Table 4-1 Comparison of QCA forecast and outturn capital expenditure 2006/07 to 2010/11 ($m nominal)

QCA Forecast	2006/07	2007/08	2008/09	2009/10	2010/11	Total
Customer requested	12.81	14.10	15.56	16.82	19.40	78.69
Network Augmentation	1.49	2.46	2.94	5.54	0.09	12.52
Network renewal	6.52	6.51	6.59	6.66	6.73	33.01
System total	**20.82**	**23.07**	**25.09**	**29.02**	**26.22**	**124.22**
Non-system	6.90	2.98	3.06	3.15	3.23	19.32
Total	**27.72**	**26.05**	**28.15**	**32.17**	**29.45**	**143.54**
Actual/Forecast	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11 F**	**Total**
Customer requested	12.76	13.74	13.57	12.23	13.24	65.54
Network Augmentation	2.09	0.41	0.52	2.47	0.81	6.30
Network renewal	3.55	2.14	8.51	9.70	9.66	33.56
System total	**18.40**	**16.29**	**22.60**	**24.40**	**23.71**	**105.40**
Non-system	5.81	2.01	1.47	0.82	0.93	11.03
Total	**24.21**	**18.30**	**24.08**	**25.22**	**24.63**	**116.43**
Variance	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11 F**	**Total**
Customer requested	-0.05	-0.36	-1.99	-4.59	-6.16	-13.15
Network Augmentation	0.60	-2.05	-2.42	-3.07	0.72	-6.22
Network renewal	-2.97	-4.37	1.92	3.04	2.93	0.55
System total	**-2.42**	**-6.78**	**-2.49**	**-4.62**	**-2.51**	**-18.82**
Non-system	-1.09	-0.97	-1.59	-2.33	-2.30	-8.29
Total	**-3.51**	**-7.75**	**-4.07**	**-6.95**	**-4.82**	**-27.11**

4.4.2 Customer requested capital expenditure

The customer initiated capital expenditure was characterised by significantly lower average costs for domestic customer connections, and the connection of several large demand customers. Total actual/forecast customer initiated capital expenditure over the period of current Access Arrangement is $65.5m, which is $13.2m less than the amount of capital expenditure approved by QCA. This variance is mostly related to the lower average actual cost for new domestic customer connections based on lesser investment in costly head-works. It is estimated that in the current access arrangement period there will be slightly more domestic customer connections than were forecast.

There were fewer connections of new small industrial and commercial customers with the majority of capital expenditure related to new connections of several large demand customers.

4.4.3 Network augmentation capital expenditure

Actual capital expenditure related to network augmentation has been less than the level assumed in the QCA's 2006 Final Approval. The variance of $6.2m was mostly related to the prudent deferral of the South Coast Supply Project, Stage 2.

10 years ago Allgas identified that the existing feeder pipeline supplying the South Coast Region will not have a capacity to support ongoing growth of the gas business. Based on the outcome of the feasibility report it was recommended to construct a 36km long 200DN class 600 steel pipeline from the existing Ellen Grove Gate Station to the Yatala Industrial Estate in 3 stages. Allgas decided to implement this recommendation in 3 Stages, and Stage 1, with 12.4km of DN200 pipeline, was constructed in the 2005/06 Financial Year.

The QCA accepted this project as prudent capital expenditure including the plan to proceed with Stage 2 in 2010. Due to slower demand growth in the South Coast Region, and better input pressure secured from the Roma to Brisbane Pipeline, APT Allgas was able to postpone the construction of the proposed Stage 2.

Major network augmentation projects completed in current Access Arrangement were the finalisation of South Coast Supply Project, Stage 1, and the Wynnum Augmentation Project.

The Wynnum Augmentation Project was necessary to be able to improve safety and integrity of supply and maintain capacity to meet levels of demand from more than 3,500 domestic, commercial and industrial customers in Wynnum, Manly and Lota. The QCA accepted a proposal for this project, which was implemented in the 2009/10 Financial Year.

4.4.4 Network renewal capital expenditure

Actual capital expenditure related to network renewal has been $0.5m higher than the level assumed in the QCA's 2006 Final Approval. The variance mostly relates to capital expenditure on the Periodic Meter Change Program, renewal of gas facilities at the end of their lives, renewal of two critical sections of high pressure steel mains, upgrades of existing metering stations for demand customers to meet FRC requirements for interval metering and a slowdown in the implementation of block mains renewal program.

The controller of the meter is obliged to develop, maintain and implement a Meter Measurement Scheme with specific requirements for meter change for testing. This is necessary to be able to check meter accuracy and its compliance with tolerance requirements. The Periodic Meter Change Program is developed to meet this regulatory requirement. This Program costed approximately $3.7m for the 2006-11 access arrangement period.

In the 2008/09 and 2009/10 Financial Years, a number of gas facilities were renewed following a risk assessment, including Runcorn Gate Station and 20 district regulator stations, at a total cost of $2.6m.

There were necessary relocations of two sections of high pressure steel mains across Hotham and Gowrie Creeks, completed in 2008/09 and 2009/10 Financial Years, at cost of $0.7m.

Further to FRC compliance requirements, existing metering stations for demand customers were upgraded to provide interval metering capability for total cost of $0.9m.

In the first two and half years of the current Access Arrangement period, there was a slow down in the block mains renewal with finalising of Toowoomba and Upper Mt Gravatt renewal projects. Continuation of Main Renewal Program started in 2009, with renewal of old mains in Brisbane inner city suburbs of Highgate Hill and Norman Park.

4.4.5 Non system assets capital expenditure

Non system capital expenditure relates to IT systems and software, motor vehicles and plant and equipment which are not part of the distribution network but are necessary for provision of gas distribution services. Actual non system capital expenditure is $11.0m.

The introduction of Full Retail Competition (FRC) in the Queensland gas market on 1 July 2007 placed new requirements on APT Allgas to improve business functions and systems including IT, telemetry and metering functions. APT Allgas undertook a closed tender and selected Hansen Technologies FRC system to be able to meet needs as follows:

- Manage basic and interval meter data for the different retailers
- Interface to the market operator (“business to business” and “business to market operator”)
- Integrate with APA Group’s financial system (Finance 1), works management system (Maximo), SCADA (CiTec) and GIS (ArcFM)

Total cost related to necessary IT systems replacements and upgrades was $8.3m.

Remaining $2.7m in non system capital expenditure is related to motor vehicles (direct labour trucks) replacement, minor upgrades at Mansfield and South Coast depots and replacement of equipment used by direct labour crews.

Actual capital expenditure related to non system capital expenditure has been less than the level assumed in the QCA’s 2006 Final Approval. The variance of $8.3m was mostly related to the deferral of some IT improvements (proposed for implemented in AA 2011/16) and less than planned expenditure for motor vehicles and equipment replacement.

4.4.6 Capital expenditure by asset class

Table 4-2 Capital Expenditure by Asset Class 2006/07 to 2010/11 ($m nominal)

	2006/07	2007/08	2008/09	2009/10	2010/11 F	Total
HP Steel Mains	1.73	0.96	1.85	0.15	0.27	4.98
Other Mains	8.06	7.15	8.00	10.18	8.60	41.98
HP Steel Services	0.04	0.07	0.17	0.15	0.05	0.48
Other Services	3.51	4.80	4.33	7.88	9.00	29.51
Regulator Stations	1.19	0.21	3.10	3.29	2.19	9.98
Metering Stations	3.88	3.08	5.16	2.75	3.60	18.46
System Total	**18.40**	**16.29**	**22.60**	**24.40**	**23.71**	**105.40**
Other	5.81	2.01	1.47	0.82	0.93	11.03
Total	**24.21**	**18.30**	**24.08**	**25.22**	**24.63**	**116.43**

APT Allgas records all conforming capital expenditure by purpose. Allocation of capital expenditure to asset classes is derived from these records and is provided in Table 4-2.

APT Allgas considers that all its actual capital expenditure in the current access arrangement period satisfies the conforming capital expenditure criteria test under Rule 79.

4.4.7 Cost efficiency of historical capital expenditure

To ensure approved capital and operating expenditure is conducted efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services, APT Allgas has conducted a thorough public tender process to engage suitably qualified contractors to undertake works.

In summary, this process involved the following steps:

- Developing the contracting strategy
- Develop contracting scope
- Public advertisement for Expression of Interest
- A defined and rigorous tender process
- Tender assessment
- APT Board approval process
- Contract implementation
- Ongoing Contract Strategy Review

A detailed summary of this approach is included in Attachment 4.6, *Tending processes Covering the period 01 July 2007 – 30 June 2010.*[15]

It should be noted that this was a public tendering process. No businesses associated with APT Allgas were involved in this tender process. There is no element of "outsourced expenditure" as envisioned in current Australian regulatory practice.

[15] As this document includes information related to the commercial operations of the contracting firms, a public version has been supplied. The complete version has been filed confidentially with the AER.

4.4.8 Capital contributions

APT Allgas undertakes a rigorous economic modelling process to ensure that all growth related capital expenditure meets the requirements of Rule 79(2)(a) and (b). The requirement for growth related capital expenditure to meet the economic feasibility test in Rule 79 determines the level of capital contribution requirements. In summary, this process operates as described below:

All capital expenditure proposals for gas network growth are evaluated with a discounted cash flow analysis of the expected revenue and costs associated with a new growth prospects. Consistent with Rule 79(4), the discounted cash flow analysis adopts:

- Current approved regulatory tariffs;
- Assumptions of average demand for residential customers;
- Sales demand estimates for individual industrial and commercial customers (for both tariff and contract groups);
- Estimates the capital and operating expenditure required to provide service to the additional customer; and
- Hurdle rate equal to the regulatory approved Weighted Average Cost of Capital.

The present value analysis for determining the capital contribution is based on an assumption of a 20 year service period in regard to residential applications, 10 years for industrial or commercial tariff applications; and duration of Contract terms for contract customer prospects.

If the internal rate of return (IRR) for the project is greater than the regulatory approved Weighted Average Cost of Capital, then it is deemed to have passed the economic feasibility test and no contribution is required. If the IRR is less than the regulatory approved Weighted Average Cost of Capital, the model will determine the minimum contribution required for that project to become economic.

The document "*APA Gas Networks Technical Policy - Economic Criteria for Justification of Capex for Growth of APA Gas Networks*", outlining this process in more detail, is attached as Attachment 4.7.

4.4.8.1 Removal of benefit from capital contributions

The asset base roll forward in this AA includes the gross amount of capital expenditure, including amounts that may be funded by capital contributions.

Rule 82(3) requires that, if the capital base includes any amount funded by a capital contribution, the AA must contain "a mechanism to prevent the service provider from benefiting, through increased revenue, from the user's contribution to the capital base". The "benefit" in this case is the revenue associated with the return on and return of the capital invested.

In this AA, capital contributions are treated as revenue in the year in which they are received. The forecast amount of capital contributions is deducted from the total revenue requirement in determining the revenue requirement to be recovered through tariffs.

Through this process, APT Allgas returns to customers, by way of lower tariffs, the full benefit associated with the return on and return of contributed capital. The up-front reduction in tariff revenue exactly equals, in present value terms, the return on and return of capital over the life of the capital investment.

4.4.9 Redundant and reused assets

APT Allgas' current AA includes a capital redundancy mechanism established under the National Gas Code.

APT Allgas does not consider that any of its assets became redundant within the meaning of the National Gas Code during the 2006-11 AA period. Similarly, no assets that were previously classified as redundant were re-used during the 2006-11 AA period.

4.4.10 Disposals

In current AA period APT Allgas disposed assets as follows:

- Other vehicles in 2008/09 Financial Year ($46k)
- 19 vehicles in 2009/10 Financial Year ($149k)
- Industrial meters M5 in 2009/10 Financial Year ($50k)
- Steel pipeline – North Coast Pipeline in 2009/10 Financial Year ($26k)

4.4.11 Surcharges and speculative capital expenditure

Over the earlier access arrangement period APT Allgas does not expect to have any non conforming capital expenditure identified as recovered by surcharge or added to a speculative investment account.

4.5 *Forecast capital expenditure*

4.5.1 Overview

APT Allgas forecast capital expenditure is shown in Table 4-3

Table 4-3 Forecast capital expenditure 2011/12 to 2015/16 ($m nominal)

	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Customer requested	15.16	16.30	17.17	18.42	19.71	86.77
Network Augmentation	1.61	1.56	3.20	2.54	2.79	11.70
Network renewal	5.81	5.90	6.41	7.34	7.15	32.61
System total	**22.58**	**23.77**	**26.78**	**28.30**	**29.65**	**131.08**
Non-system	3.21	2.07	1.48	0.68	0.53	7.97
Total	**25.79**	**25.84**	**28.26**	**28.98**	**30.18**	**139.05**

Table 4-4 Forecast Capital Expenditure by Asset Class 2011/12 to 2015/16 ($m nominal)

	2011/12	2012/13	2013/14	2014/15	2015/16	Total
HP Steel Mains	1.44	1.73	3.46	2.80	3.09	12.53
Other Mains	7.51	8.00	8.33	8.86	9.37	42.07
HP Steel Services	0.06	0.06	0.07	0.07	0.08	0.33
Other Services	8.79	9.43	9.91	10.61	11.32	50.05
Regulator Stations	1.23	0.95	0.91	0.95	0.99	5.03
Metering Stations	3.56	3.60	4.11	5.00	4.81	21.08
System Total	**22.58**	**23.77**	**26.78**	**28.30**	**29.65**	**131.08**
Non System	3.21	2.07	1.48	0.68	0.53	7.97
Total	**25.79**	**25.84**	**28.26**	**28.98**	**30.18**	**139.05**

The basis for the forecast of capital expenditure is outlined in the following sections.

4.5.2 Forecast methodology for estimating capital expenditure

Budget cost estimates are based on the contractor's current material and direct labour costs, applicable overhead charges and compared to historical actual costs on similar projects. Unit costs have been estimated separately for all the proposed capital expenditure projects with split by cost subcategories: material, direct labour, contractors and overheads. These estimates, developed using actual data and engineering best assessments, are in 2010/11 dollars. Detailed information about unit rates and quantities used for capital expenditure forecast are shown in the Capital Expenditure Plan.

The forecasted unit rates have been escalated using Access Economics' real labour cost escalation rates described in next section.

As described above, APT Allgas has outsourced its capital works program (material and labour) through a public tender process, ensuring market prices for the services are incorporated. As described below, APT Allgas continues to test the market in regular intervals to ensure that the proposed projects will be executed at the lowest sustainable cost. Competitive tendering for supply of material is planned to be organised each year and for provision of capital works services in 2 to 3 year intervals.

APT Allgas has engaged Parsons Brinckerhoff to provide an independent assessment of the estimation of unit rates used in the proposed expenditure program.

Along with strategic planning process, this section shows how forecast capital expenditure complies with Rule 79(1). Justification in accordance with Rule 79(2) is discussed under individual capital expenditure drivers.

4.5.2.1 Escalators

The forecast Real Labour Cost Escalation Rates are based on AER's report on labour cost escalation "Forecast growth in labour costs"[16] produced by Access Economics on 16th March 2010.

Table 4-5 Forecast Real Labour Cost Escalation Rates

	2011/12	2012/13	2013/14	2014/15	2015/16
Cost Escalation Rates (%)	0.90	1.30	1.50	1.60	1.30

[16] Access Economics – *Forecast growth in labour costs* 16 March 2010, Report by Access Economics Pty Limited for the Australian Energy Regulator, Table 6.5 – Utilities.

The above escalation rates are relevant to Queensland utilities and are used to forecast all components of capital expenditure including material, direct labour and contractors.

4.5.3 Capital projects by driver

4.5.3.1 Customer Requested Capital Expenditure – methodology and forecast

The forecast of capital expenditure related to new residential, commercial and industrial customer connections is directly related to forecast of new customer connections.

Historical data is used to estimate average length of main extensions and average total costs per individual customer.

The proposed unit rates for residential customer connections are based on current schedule of rates with preferred contractor, actual material and direct labour costs and average overhead charges. This rate is compared with available historical average costs and adjusted, if required, to produce the most realistic forecast.

The proposed unit rates for commercial and industrial customer connections are based on historical average costs.

The capital expenditure in this category is initiated by need to provide capacity to meet projected demand for new customers and potential additional future services and is justified under Rule 79(2)(b) on the grounds that 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.

4.5.3.2 Network Augmentation – methodology and forecast

As a part of the Strategic Capital Expenditure Process a number of network capacity issues were identified and addressed in the Risk Management Plan.

The proposed unit rates for individual projects are based on historical costs for similar projects.

The network augmentation capital expenditure projects are justified under Rule 79(2)(c) on the grounds that they are necessary to maintain the capacity to meet current customer demands including safety and integrity of supply. The additional benefits are increased network capacities to meet potential future customer demands.

Separate business cases were developed for critical projects to provide supporting information and justifications. The summary of the proposed projects are as follows.

Upgrade Tingalpa Gate Station[17]

Based on the assessment of the past performance of Tingalpa Gate Station and the forecast of additional future requirements, the identified critical needs were to improve safety, integrity and capacity of the existing station including filtration, odourisation, electrical installations, earthing and critical valves.

This project includes increases of design capacity and establishment of a new class 300 outlet for the existing Cleveland Pipeline.

Augmentation of existing high-pressure steel network supplying gas to Surfers Paradise and Broadbeach[18]

The existing high-pressure steel network supplying natural gas to Surfers Paradise and Broadbeach currently has very limited spare capacity that is reduced every year with new customer connections. It is estimated that in winter 2013 there is a very high probability that the available spare capacity will be not sufficient to meet customer demands.

A new 3.6km long DN100 high pressure steel main is planned which will increase the capacity of the existing high-pressure network by approximately 4,000Sm3/h[19], which will be sufficient to meet future customers demand up to 2030. An additional benefit is the establishment of a high-pressure ring main that will improve reliability of supply to Southport, Surfers Paradise, Broadbeach, Ashmore, Benowa and Bundall.

South Coast Supply Project Stage 2[20]

The proposed Stage 2 of South Coast Supply Project comprises the construction of 10.2 km of DN200 class 600 pipeline from the end of Stage 1 to Logan Reserve and connection to the existing South Coast feeder pipeline. The construction of Stage 2 should be completed before winter 2016 to ensure gas supply safety and reliability for the South Coast Region.

An additional benefit is that the proposed Stage 2 pipeline will enhance a security of supply for the risk of failure of the existing feeder main, due to either third party damage or structural failure.

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[17] Business Case – Upgrade Tingalpa Gate Station. See Attachment 4.8.

[18] Business Case - Augmentation of existing high-pressure steel network supplying gas to Surfers Paradise and Broadbeach. See Attachment 4.8.

[19] Standard cubic metres per hour

[20] Business Case - South Coast Supply Project Stage 2. See Attachment 4.8.

Pressure Upgrade for Cleveland Pipeline

The Tingalpa Gate Station high-pressure steel network has a 15km long DN100 steel pipeline supplying Cleveland with MAOP of 5,000kPa that is not directly connected to gate station and currently operates at 1,000kPa. There are potential domestic, commercial and industrial developments that may require significant additional demand in the next few years. This additional demand will require increase of supply pressures to approximately 2,000kPa.

The upgrade of the Tingalpa Gate Station, currently under construction, will provide an additional class 300 outlet that will be able to supply gas at sufficient pressure levels.

This project recommends construction of a new approximately 200m long DN100 class 300 pipeline to link the Cleveland Pipeline to the proposed new outlet from Tingalpa Gate Station. The timing of this project is directly related to potential customer demands.

Broadbeach High Pressure Polyethylene Network Augmentation

The existing high pressure polyethylene networks in Surfers Paradise and Broadbeach have difficulty to meet current and especially proposed new customer demands. The proposed polyethylene link mains are required to improve the capacity of the network and meet customer demands.

Minor Network Augmentation Projects

Network modelling has focussed on maintaining capacity in the principal supply mains. It is expected that there will be a number of local sub network capacity issues to be addressed on an annual basis, pending the replacement and upgrade of the old low and medium pressure networks.

The majority of the issues are associated with new developments, the use of high instantaneous demand appliances within low pressure networks, and reduced capacity as result of water ingress.

Capacity shortfalls are typically identified through the annual pressure survey programme and customer supply complaints. Invariably an additional interconnection, supply regulator or a pressure upgrade is required to boost local system pressures to levels consistent with maintaining a safe and reliable supply of gas to consumer premises.

4.5.3.3 Network Renewal – methodology and forecast

The distribution network assets (mains, services, meters, regulators, filters, valves, odourisation units, electrical and SCADA installations etc.) have limited technical and economical lives and require, at some point of time, replacement or upgrades to mitigate identified risks including safety to public, reliability of supply, environmental hazard, regulatory non-conformance etc.

The network renewal projects are justified under Rule 79(2)(c) on a ground that the capital expenditure is necessary to maintain and improve the safety and integrity of services and to comply with regulatory requirements.

A number of small asset renewal projects were implemented each year when required based on completed risk assessment and capital expenditure approval.

The controller of the meter is obliged to develop, maintain and implement a Meter Measurement Scheme with specific requirements for meter change for testing. This is necessary to be able to check meter accuracy and its compliance with tolerance requirements. The Periodic Meter Change Program[21] is developed to meet this regulatory requirement.

The Mains Replacement Plan covers the low and medium pressure networks of the Brisbane metropolitan area containing the remaining cast iron and unprotected steel mains in the APT Allgas Networks. APT Allgas operates nearly 3,000 km of gas mains, including some 400km of remaining cast iron and unprotected steel mains. It is recommended to replace all remaining cast iron and unprotected steel mains within the APT Allgas networks based on safety risk, deteriorating condition, integrity and inadequate capacity. The existing old low and medium pressure networks in Brisbane are approaching the end of their technical and economical life, have elevated operation, maintenance and UAFG costs, unsatisfactory supply reliability and with this level of leaks, these mains may lead to an increase in environmental and public safety risks. The “old networks” have limited capacity for efficient growth.

In total, it is proposed to replace approximately 435km of low and medium pressure mains over the next 25 years. This option is recommended because it provides a minimum necessary rate of mains renewal to slowly reduce the current level of maintenance and UAFG costs and at same time maintain current level of capital expenditure that APT Allgas can allocate to the MRP based on project prioritising.

The proposed unit rates for individual projects are based on average historical costs.

4.5.3.4 Non system assets – methodology and forecast

Non system capital expenditure is related to IT systems and softwares, motor vehicles and plant and equipment which are not part of the distribution network. The proposed projects are justified under Rule 79(2)(c) on a ground that the capital expenditure is necessary to maintain and improve the safety and integrity of services and to comply with regulatory requirements.

[21] Business Case – Periodic Meter Change Program. See Attachment 4.8.

Separate business cases were developed for critical projects to provide supporting information and justifications. The summary of the proposed projects are as follows.

Upgrade of information technology applications[22]

This project is to support the periodic upgrade of APA's information technology applications as follows:

- Maximo – Full Retail Contestability (FRC), Works management – installed 2007;
- Control M – FRC, Batch processing – last upgrade 2004;
- WebMethods Fabric – FRC Middleware – last upgrade 2007;
- WebMethods – FRC Gateway – last upgrade 2006; and
- RedBox – FRC Metering and Billing – installed 2006.

  The expenditure is necessary to satisfy Retail Market Procedures (Queensland) and APT Allgas business requirements in order to maintain the integrity of services by ensuring:

- Continuation of IT vendor support;
- Security and integrity of business information;
- Stability of IT systems; and
- Compliance of IT systems.

Information technology infrastructure upgrades and renewals[23]

This project is required to support the periodic upgrade of APA IT Infrastructure (i.e. upgrades and renewals) and the standardised use of Virtualisation, Storage Area Network and Server Blade technologies over the Access Arrangement period.

The scope of work includes:

- The standardised use of Virtualisation, Storage Area Network and Server Blade technologies; and
- Upgrades / renewals to the GIS server.

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[22] Business Case - Upgrade of information technology applications. See Attachment 4.8.

[23] Business Case - Information technology infrastructure upgrades and renewals. See Attachment 4.8.

The expenditure is necessary in order to maintain the integrity of services by ensuring:

- Continuation of IT vendor support;
- Security and integrity of business information;
- Stability of IT systems; and
- Compliance of IT systems.

Road Map Initiatives[24]

This project supports the business strategic direction while addressing existing architectural weaknesses and functionality that restrain business performance.

The strategic plan proposes to introduce four projects:

- National Works Management;
- Field Data Capture;
- Billing Optimisation;
- Advanced Asset Management.

The project is designed to take advantage of hardware end of life and software upgrade opportunities to deliver enhanced functionality and reduce total costs of IT ownership.

The forecast cost of the proposed RMI project over the next Access Arrangement period is approximately $2.839m in capital expenditure and $630,000 of non-recurrent operating expenditure.

The recommended project will allow APT Allgas to comply with regulatory requirements and to meet its objectives of cost effectiveness and operational efficiency.

Knowledge management[25]

The changing environment in which APT Allgas operates necessitates a need to better document the business knowledge held by employees and to develop a more

[24] Business Case - Road map initiatives. See Attachment 4.8.

[25] Business Case - Knowledge management. See Attachment 4.8.

formal process to manage the documentation developed. This project includes the following deliverables:

- Scoping of the requirements and approach required by APA to manage knowledge across the business;
- Documentation of end to end business processes of the whole business; much the same as was done for FRC activities; and
- Development and implementation of a document/records management system.

The proposed $475,000 in capital expenditure and $584,000 in operating expenditure is necessary to improve the capture and access of knowledge to assist with better decision making by the business and improve in the retention of knowledge within the organisation.

SCADA upgrades[26]

This project is to support the periodic upgrade of the SCADA system over the next Access Arrangement period for a forecast cost of $666,000.

Significant investment has been made in recent years to ensure that APT Allgas systems, including the SCADA system, meet the obligations as set out in the Retail Market Procedures. APT Allgas needs to ensure this investment is managed and maintained.

Upgrading the SCADA system is necessary to maintain the integrity of services and address risk of non-compliance with regulatory requirements and potential adverse financial and reputation impacts.

Other non system assets[27]

It is planned to make provision for the expected costs of additional and replacement essential tools, equipment and other non reticulation items to ensure the safety of operatives and to comply with APA's Safety Non Negotiables, which refer to a set of requirements specified in APA's Health Safety and Environment Management System and the Workplace Health & Safety Act 1995.

APT Allgas considers that the proposed $1.255M in capital expenditure for ongoing requirements of essential tools, equipment and other non reticulation items is necessary in order to maintain the safety of services and to comply with regulatory obligations and requirements.

[26] Business Case - SCADA upgrades. See Attachment 4.8.

[27] Business Case - Other non system assets. See Attachment 4.8.

4.5.4 Cost efficiency of forecast capital expenditure

With the pending expiry of the contracts arranged under the rigorous tender process described in section 4.4.7, APT Allgas has sought expressions of interest for contractors to conduct capital and operating works on the network. This process is ongoing at the time of filing. However, APT Allgas sought quotations for works associated with extending the existing contracts pending the finalisation of the new tender process. These rates are reflected in the forecast of capital and operating expenditure for the upcoming AA period.

A more detailed outline of the forward looking tender process is included in confidential Attachment 4.9, *Tendering processes Covering the period 01 July 2011 – 30 June 2016*.[28]

It should be noted that this process is an extension of the public tendering process described in section 4.4.7; no businesses associated with APT Allgas are involved in this tender process. There is no element of "outsourced expenditure" as envisioned in current Australian regulatory practice.

4.5.5 Capital contributions

As discussed in section 4.4.8 on historical capital contributions, APT Allgas undertakes a rigorous economic modelling process to ensure that all growth related forecast capital expenditure meets the requirements of Rule 79(2)(a) and (b). The requirement for growth related capital expenditure to meet the economic feasibility test in Rule 79 drives the level of capital contribution requirements.

For forecast purposes, this process operates in the same manner as that described in section 4.4.8, but with updated forecasts of capital costs for connection of new loads, and the proposed Weighted Average Cost of Capital as the hurdle rate in the IRR calculations.

The document "*APA Gas Networks Technical Policy - Economic Criteria for Justification of Capex for Growth of APA Gas Networks*", outlining tis process in more detail, is attached as Attachment 4.7.

4.5.6 Redundant and reused assets

APT Allgas does not forecast that any of its assets will be made redundant during the AA period and does not expect to re-use any assets that were previously classified as redundant during the period.

[28] As the information included in this document has the potential to inappropriately influence the outcome of the tender process, it has been filed with the AER confidentially.

Capital Redundancy mechanism

APT Allgas has retained its capital redundancy policy included in the 2006-11 AA, however it has revised this policy in the 2011-16 AA to reflect the move to the NGR.

The revised capital redundancy mechanism will apply from the start of the 2011-16 AA period, and includes a provision for costs associated with a decline in the volume of sales of services provided by means of the covered network to be shared between APT Allgas and users. The cost sharing mechanism is identical to that applying in the 2006-11 AA.

APT Allgas considers that the mechanism is necessary to provide certainty for APT Allgas as to how redundant capital will be treated during the AA period, and to reduce the risks associated with redundant capital by providing a mechanism to share costs associated with a decline in volume with users as appropriate. Disposals

4.5.7 Surcharges and speculative capital expenditure

APT Allgas does not expect to have any forecast non conforming capital expenditure to be identified as recovered by surcharge or added to a speculative investment account.

5 Capital base

5.1 Reconciliation of opening capital base

The QCA 2006-11 AA determination indicates an opening capital base at 01 July 2006 of $303.2m. This necessarily reflects a forecast of capital expenditure for the 2005/06 fiscal year. Rule 77(2)(a) requires that the opening capital base must be adjusted for any difference between estimated and actual capital expenditure included in that opening capital base.

At the time of the sale of the Allgas business to APA Group, no detailed reconciliations between the estimated RAB approve by the QCA and the actual RAB were provided. However, Allgas filed regulatory accounts with the QCA, and APT Allgas proposes to use the opening capital base per the Allgas regulatory accounts as the opening capital base for the purposes of this Access Arrangement.

Note 2 to the Allgas 2005/6 regulatory accounts indicates that the closing capital base at 30 June 2006 is $303.2 million less $513k for assets used to provide recoverable works. The 30 June 2006 closing capital base attributable for the covered pipeline is clearly shown as $302.687m.

APT Allgas has therefore used the opening capital base of $302.687m, based on the Allgas 2006 Regulatory Accounting Statement as audited by the Queensland Audit Office.

There is no difference in asset lives from those approved by the QCA during the current AA period (2006-11).

5.2 Depreciation

5.2.1 Historical depreciation

The capital base has been rolled forward using the historical forecast depreciation included in the current QCA-approved AA for the 2006-11 period, as presented in Table 5-1.

Table 5-1 Historic Depreciation ($m, nominal)

	2006-07	2007-08	2008-09	2009-10	2010-11
Depreciation per AA June 2006	8.1	9.5	10.4	11.4	11.9

5.2.2 Revision of network asset economic lives

APT Allgas has reviewed the depreciable lives included in the 2006-11 AA, and found them to be out of line with respect to other approved Australian Access Arrangements. Indeed, the current regulatory economic lives of APT Allgas assets are the longest of any gas network in Australia.

A review of historical documentation from the early years of network regulation in Queensland indicates that Allgas had adopted the engineering technical lives of assets that were defined by Gutteridge Haskins & Davey Pty Ltd (GHD) in their report *Valuation of Allgas Gas Distribution Network Assets*, June 2000:[29]

> The technical lives of the gas distribution assets set out above have been established on a conservative basis which takes into consideration the corrosion risk, other forms of physical deterioration and excessive maintenance costs towards the end of their useful lives.
>
> AEL advised that connection to the supply from the Cooper Basin is already in place. Other alternative supply sources, as described in an earlier section of this report, are currently being explored. The risk of natural gas depletion during the remaining life of the AEL assets is, therefore, not considered an issue.
>
> The economic lives of the distribution assets are therefore taken to be the same as the technical lives, given the likely availability of gas supply.

In summary, GHD concluded that the economic lives of the distribution assets are to be the same as the engineering technical lives. However, GHD failed to acknowledge that there are other factors to be considered in defining economic lives of assets.

One of the considerations in determining the economic useful like is the scope for depreciation to fund steady state network renewals. In the 2006-11 AA, the depreciation building block for allowable revenue, does not provide APT Allgas with sufficient cash flow to finance its ongoing network renewal costs. Effectively, in the years 2006/7 – 2011/12, the depreciation allowance was not sufficient for APT Allgas to complete many critical network reliability projects; the cash flow generated by depreciation is below the required amounts to fund stay in business capital expenditure alone.

APT Allgas submits that the estimation of economic lives for gas distribution assets has been well studied since the GHD study was commissioned in 2000. APT Allgas therefore does not propose to repeat the arguments and analysis put forward over the years, but rather proposes to capitalise on the outcomes of that analysis by adopting a suite of economic lives as currently approved in the AER's approved AA for the ActewAGL gas distribution network.

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[29] Gutteridge Haskins & Davies, *Valuation of Gas Distribution Network Assets*, June 2000 section 6.3.

The following table illustrates current economic lives for APT Allgas in comparison to ActewAGL as currently approved by the AER,[30] and proposed revised economic lives for APT Allgas.

Table 5-2 Asset Economic Lives (years)

Asset Class	Allgas previous AA	ActewAGL approved	APT Allgas proposed
HP Steel mains	105	80	80
HP Services	105	50	50
Distribution mains and services	PVC – 30 PE – 80 Steel – 45 Copper – 85 Cast iron – 80	50	50
District Regulators	50	15	40
Contract Meters	30	15	15
Tariff Meters	25	15	15

APT Allgas submits that the proposed revision of economic lives for APT Allgas assets meets the requirements of Rule 89(1)(c), on the grounds that the previous asset lives place unreasonable cash flow constraints on the business, as envisioned in Rule 89(1)(e).

5.2.3 Forecast depreciation

The depreciation schedule for 2011/12 – 2015/16 has been calculated based on prospective application of the revised economic assets lives outlined above.

APT Allgas has applied a straight-line methodology in determining future depreciation. The real straight line depreciation method ensures:

- the value of each asset (with adjustment for inflation through indexation of the capital base) is recovered only once over the asset's economic life thus meeting the requirements of Rule 89(1)(d);
- the deduction of the same real value of depreciation in each year of an asset's economic life; and

[30] AER, *Access arrangement for the ACT, Queanbeyan and Palerang gas distribution network* - 1 July 2010 – 30 June 2015, April 2010, table 6.2, p20.

- that as the APT Allgas market is at a mature stage, with steady and predictable growth, investment, and cash flow, there is no need for deferral of depreciation pursuant to Rule 89(2).

APT Allgas intends to continue its current practice of basing the calculation of depreciation of the capital base on forecast capital expenditure. This is in accordance with Rule 90(1).

Forecast regulatory depreciation for the next AA period, calculated using the methodology outlined above,[31] is presented in Table 5-3.

Table 5-3: Forecast depreciation over next AA period ($m nominal)

	2011-12	2012-13	2013-14	2014-15	2015-16
Regulatory depreciation	1,911	986	911	854	1,263

5.3 *Capital Base roll forward*

The opening capital base for the access arrangement period[32] is shown in Table 5.4 below.

Table 5.4 – Opening capital base for the access arrangement period ($'000 nominal)

	2005/06 [33]	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Opening capital base	275,511	302,687	326,011	350,510	370,150	396,203	421,673
plus capex	29,689	25,194	19,265	24,979	26,360	26,428	
plus speculative capex	-	-	-	-	-	-	
plus re-used redundant assets	-	-	-	-	-	-	

[31] Depreciation shown in this table is calculated by the AER's Post Tax Revenue Model, and is therefore calculated net of indexation of the capital base.

[32] As required by Rule 72(1)(b)

[33] Information on the roll forward of the 2005/6 capital base is drawn from the Allgas 2005/06 regulatory accounts, Schedule E.

less depreciation	7,359	8,148	9,462	10,404	11,386	11,934	
plus indexation[34]	7,535	6,278	14,696	5,111	11,304	10,975	
less redundant assets	-	-	-	-	-	-	
less disposals and transfers	2,689	-	-	46	225	-	
Closing capital base	302,687	326,011	350,510	370,150	396,203	421,673	

5.3.1 Projected capital base over the access arrangement period

The projected capital base for the access arrangement period[35] is shown in Table 5.5 below.

Table 5.5 – Projected capital base for the access arrangement period ($'000 nominal)

	2011/12	2012/13	2013/14	2014/15	2015/16
Opening capital base	**421,673**	**446,520**	**472,335**	**500,740**	**529,946**
plus forecast capex	26,758	26,801	29,316	30,060	31,311
less forecast depreciation	1,911	986	911	854	1,263
less forecast disposals	-	-	-	-	-
less forecast redundant assets	-	-	-	-	-
Closing Capital Base	**446,520**	**472,335**	**500,740**	**529,946**	**559,994**

[34] 2005/06 numbers include allocation difference of $1,768,000 as per the Allgas 2005/06 regulatory accounts, Schedule E.

[35] As required by Rule 72(1)(c)

6 Weighted Average Cost of Capital

6.1 Introduction

6.1.1 Context

In determining its proposed estimate of the Weighted Average Cost of Capital (WACC) to apply to the APT Allgas distribution network, regard must be given to the relevant provisions of the National Gas Law (NGL) and the National Gas Rules (NGR). The overarching objective as set out in the NGL is to:

> ...promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

Amongst other things, the revenue and pricing principles provide that the service provider should be able to recover the efficient costs of providing the Reference Service, and earn a return that is commensurate with the risks involved in providing that Reference Service.

Rule 87 of the NGR provides that:

1) The rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.

2) In determining a rate of return on capital:

   (a) it will be assumed that the service provider:

      (i) meets benchmark levels of efficiency; and

      (ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice; and

   (b) a well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be used; and a well accepted financial model, such as the Capital Asset Pricing Model, is to be used.

Rule 74(2) also provides that any forecasts or estimates are arrived at on a reasonable basis and must represent “the best forecast or estimate possible in the circumstances”.

In reviewing each of the parameter estimates, reference has been made to the previous determination made for APT Allgas by the Queensland Competition Authority (QCA) in 2006, as well as relevant AER precedent.

The APA Group engaged Synergies Economic Consulting (Synergies) to review certain aspects of the WACC to apply to APT Allgas. The accompanying report by Synergies (the Synergies Report) addresses the following areas:

- issues in estimating the cost of debt
- estimating the cost of debt and equity in the current market environment
- the market risk premium (MRP)
- beta
- gamma.

6.1.2 Determining a reasonable WACC estimate

A fundamental concern for the APA Group is that the regulated rate of return provides an adequate incentive for the business to invest in the APT Allgas network, particularly given the difficult and uncertain market conditions that have been experienced following the global financial crisis. The Synergies Report notes the continuing uncertainty prevailing in the market and the renewed concerns that have emerged regarding the stability of the world economy, including the prospect of a ‘second wave’ of the crisis (refer section 5 of the Synergies Report).

Synergies also examined the historical difference between the returns on debt and equity since 1990 and the impact of the global financial crisis on these returns (refer section 4 of the Synergies Report). Actual returns to equity holders fell dramatically as a consequence of the crisis, with such events typically followed by an increase in forward-looking expected returns for these investors. Yields on corporate debt have also increased dramatically, reflecting the additional compensation required by lenders for the perceived increase in risk.

What the analysis also highlights is that an examination of recent regulatory decisions, which apply the standard methodologies and assumptions used by regulators, has seen a contraction in the difference between the expected returns on equity and debt. This largely reflects the fact that the return on debt is set based on prevailing market rates at the time of the regulatory reset, whereas two of the main components of the return on equity, being beta and the MRP, are assumed to be more stable through time and hence tend to be based on long-term averages (noting the AER’s decision to increase the MRP to be applied to electricity network businesses to 6.5% in 2009 in acknowledgment of the impact of the global financial crisis).

Over the period between 1990 and 2007, the average difference between the return on debt (based on the UBS Australian Composite Index) and equity (based on the All Ordinaries Accumulation Index) was around 6.07%. If this period was extended to include the abnormal market conditions experienced as a consequence of the global financial crisis, the difference was 2.85%. However, this is based on actual observed returns and does not mean the investors' expected returns have fallen since the crisis - indeed the opposite would be expected.

Synergies suggests that a 'reasonableness' check of the difference between the estimated return on debt and equity requires that this difference should at least be around 4.5% (which is the mid-point between 2.85% and the pre-crisis average of 6.07%). This is considered conservative given the average difference prevailing up until the crisis commenced was 6.07%. This will be revisited at the end of this Chapter.

What this analysis continues to highlight is the considerable uncertainty underpinning the estimation of WACC, particularly for parameters such as beta, gamma and the MRP. This uncertainty remains despite the use of increasingly sophisticated analysis and techniques. It is noted that many of these techniques are applied to historical data, which is often considered the best estimate of the future. This may be reasonable when market conditions are stable however when they are not, as is the case now, it can be extremely difficult to reliably measure expectations of future returns.

This in turn means that the risk of regulatory error in setting a WACC for a regulated business in the current environment is particularly high. As noted in the Synergies Report, this risk has asymmetric consequences, as under-estimation could lead to under-investment in essential infrastructure, which is considered to have worse economic and social consequences than over-estimation. The APA Group emphasises the importance of having regard to this risk of error – and its asymmetric consequences – in setting the WACC that will be applied to APT Allgas for the next five years.

6.2 Risk-free rate

While the NGR does not provide any specific requirements in relation to estimating the risk-free rate, it must be consistent with the 'prevailing market for funds'. It is noted that the approach generally applied by the AER is to require the risk-free rate to be set as close as possible to the start of the regulatory control period.

The APA Group also notes that under the National Electricity Rules, the regulated business can propose the relevant period to the AER for approval. Further, this is done confidentially, which enables the business to execute any necessary refinancing or hedging strategies without notifying the wider market as to when this may occur (as such notice could provide financial market participants with an opportunity to exploit the possibility that this may occur over this period).

For the purpose of calculating the indicative WACC estimate, the risk-free rate has been estimated in accordance with standard regulatory practice, which is a twenty day average of the ten year Commonwealth Government bond yield (annualised). The average was taken over the twenty business days ending 27 August 2010. The resulting average was 5.07%.

6.3 Gearing

A debt to total value ratio of 60% was applied in the QCA's 2006 determination in relation to APT Allgas, and it is noted that this is the value that has been most commonly applied to energy transmission and distribution businesses. It is noted that the appropriateness of this gearing level for a gas network business has not been revisited in any detail more recently. Synergies has raised a concern that it is possible that a BBB+ rating is no longer compatible with 60% gearing for APT Allgas, particularly since the commencement of the global financial crisis.

APA reserves the right to review this assumption following the release of the Draft Decision. However, for the purpose of setting its indicative tariffs in this regulatory proposal, gearing of 60% has been proposed for APT Allgas, along with a notional credit rating of BBB+, which was applied in the AER's most recent determination for Jemena Gas Networks.

6.4 Debt margin

The estimation of the debt margin has proven extremely difficult given the significant reduction in liquidity that occurred following the commencement of the sub-prime crisis in 2007. One of the most contentious issues has been the source of the data to be used, with the two recognised data providers, being Bloomberg and CBA Spectrum, using different (and unknown) methods to fit a yield curve to the very limited market data (an additional problem with the use of CBA Spectrum data is that it can only be accessed by CBA customers).

There have been no ten year BBB+ bonds issued in the Australian market for some time. The longest maturity for which Bloomberg publishes yields in the BBB category (which includes BBB-, BBB and BBB+) is currently seven years. (References in this Chapter to' BBB' in the context of Bloomberg estimates is therefore assumed to include BBB+. CBA Spectrum does publish a separate yield curve for BBB+.)

The APA Group notes that this issue has come under considerable scrutiny recently. This includes the testing method that has been developed by the AER to select the data source that will be used over the relevant averaging period. The APA Group considers that a prudent response to this problem would be to take an average of the Bloomberg and CBA Spectrum estimates, particularly as the method used by each data provider to construct its yield curve remains unknown. Further, while the AER has developed a robust method, it only tests the extent to which each data source predicts yields on bonds with shorter maturities. The key question of relevance here is the reliability of each data source at the longer end of the yield curve, where there is no market data.

The other problem that has emerged in recent months is the cessation of publication of certain corporate bond yields by Bloomberg. Having ceased publishing long-term yields on A rated bonds in 2009, the AER (and others) reverted to the AAA corporate bond yield curve to extrapolate the seven year BBB yield (by adding the difference between the yields on seven and ten year AAA bonds). However, Bloomberg ceased publishing these AAA yields in 2010, which means that there are currently no ten year corporate bond yields published by Bloomberg.

The Synergies Report has examined the implications of Bloomberg's most recent decision for estimating a ten year BBB yield using this data source (refer Section 3 of the Synergies Report). It concludes that a reasonable alternative is to use the implied term structure of the BBB yield curve, that is, extrapolate the seven year yield based on the difference between the five and seven year yields. It compares the use of this method against the actual Bloomberg ten year BBB yield over a period of time when this data was still published, being the two years prior to its cessation of publication in 2007. The average difference was only 4 basis points.

While there are difficulties in applying any extrapolation method in the current environment, APA Group considers this a reasonable solution in these circumstances. It is certainly considered preferable to no extrapolation, as one would expect that the premium required to commit funds to a BBB borrower for ten years would be particularly high in the current illiquid market.

It is therefore proposed that the debt margin is estimated based on the average of:

- CBA Spectrum's ten year BBB+ yield, which over the twenty days to 27 August 2010 was 3.23% (annualised); and
- Bloomberg's ten year BBB yield, which is estimated by extrapolating the seven year yield based on the difference between the five and seven year yields. Over the twenty days to 27 August 2010 the margin was 4.47% (annualised).

The resulting debt margin is 3.85%.

Debt raising costs are considered in section 6.10 below.

6.5 *Market risk premium*

Since the finalisation of its WACC Statements to apply to electricity transmission and distribution in 2009[36], the AER has applied a MRP of 6.5% in electricity and gas

[36] Australian Energy Regulator (2009). Electricity Transmission and Distribution Network Service Providers: Statement of the Revised WACC Parameters (Transmission), Statement of Regulatory Intent on the Revised WACC Parameters (Distribution).

decisions. The AER determined to increase the MRP to 6.5% in response to the market conditions experienced following the commencement of the global financial crisis.

It is noted that submissions have been made following this determination to suggest that this value is still too low. For example, the Victorian electricity distribution businesses submitted new evidence by Officer and Bishop regarding updated estimates of the MRP.[37] While short-term forward looking estimates are generally seen as unstable, Officer and Bishop examined the implied volatility of options on the ASX 200 and spreads on corporate debt, and concluded that these estimates are sufficiently robust and reliable to warrant a departure from the long-term average. They concluded that the most appropriate value for the medium-term forward-looking MRP is 11% and their best estimate for the MRP over the period between 1 January 2011 and 31 December 2015 is between 7% and 8%.

The AER has rejected this analysis as it was not seen as sufficiently persuasive to warrant a departure from its preferred value of 6.5%. Instead, it has suggested that market conditions have stabilised and mooted a possible reduction back to 6%, which is the value that it applied previously and is what it considers to be the long-term average.[38] However, it is not clear how the AER will assess whether or not market conditions have 'stabilised' and the case of the MRP, determine that it might be appropriate to revert to the long-term average.

Both positive and negative sentiments have been expressed regarding the future outlook for the world economy. The Synergies Report highlights a number of credible sources that suggest that considerable risks remain. Overall, the prevailing theme remains one of uncertainty. The expected MRP is not directly observable. Despite the increasingly sophisticated analysis and techniques that can be applied, this is one of a number of areas in WACC estimation that is inherently uncertain.

The Officer and Bishop analysis suggests that the value of the forward-looking MRP is most likely to be above 6.5%. The analysis that Synergies has undertaken that compares the historical returns on debt and equity also suggests that to the extent that debt margins spiked following the commencement of the crisis and have continued to remain at these levels, the premium that equity investors now require will have similarly increased. The Officer and Bishop analysis concluded that over the next five years the MRP is expected to be between 7% and 8%. Synergies has therefore concluded that 6.5% is currently likely to be a 'lower bound' estimate of the forward-looking MRP for the horizon of APT Allgas' regulatory control period.

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[37] Professor B. Officer and Dr. S. Bishop (2009). Market Risk Premium, Estimate for 2011-2015, October.

[38] For example, in its Final Decision in relation to ETSA Utilities, the AER stated: "The AER considers that the Australia market is showing continued signs of recovery from the GFC and that there are some indicators that the MRP may have already returned to the long-term equilibrium of 6 per cent." Refer: Australian Energy Regulator (2010). Final Decision, South Australia Distribution Determination 2010-11 to 2014-15, May, p.175.

A MRP of 6.5% has been proposed for APT Allgas and this is considered conservative.

6.6 *Beta*

In 2006 the QCA determined an equity beta of 1.1. The main conclusions drawn by the QCA in making this decision were as follows:

- Industrial and commercial customers account for a higher proportion of APT Allgas' demand profile relative to comparable service providers in other states, who are more reliant on residential demand. This in turn exposes APT Allgas to higher systematic risk.
- Gas network businesses face higher systematic risk than electricity because they are exposed to greater competition from alternative energy sources. This risk is systematic in nature because it exposes the business to higher revenue risk (to the extent that this revenue risk is systematic, as will be shown below) and it also materially reduces APT Allgas' market power.

The Synergies Report examines the appropriate beta to apply to the APT Allgas network. As part of its analysis it undertook a review of comparable companies, and a detailed first principles analysis.

6.6.1 Review of comparable companies

Synergies examined a global sample of comparable gas distribution businesses, with a focus on Australian and US firms. It highlighted the issues associated with estimation error and the importance of having due regard to the relevance and quality of the estimates if any reliance is to be placed on these estimates to establish a value for beta.

After filtering the sample to exclude businesses that did not have sixty months of data, and estimates that had t-statistics of less than two, the sample was reduced to two Australian firms (APA Group and Envestra) and five US firms, only one of which would appear to be primarily engaged in gas distribution. It therefore concluded:[39]

> We consider that three firms (one of which is a US firm) is an inadequate sample to enable any robust observations to be made regarding betas of gas distribution firms.

Reference was also made to the sample relied upon by the AER as part of determining the beta to apply to electricity transmission and distribution businesses and submissions that had been made by the Joint Industry Associations (JIA), which

[39] Synergies Economic Consulting (2010). Estimating a WACC for the Allgas Distribution Network: Key Issues in the Current Environment, p.46.

highlighted the problems with the data that was relied upon. For example, the Allen Consulting Group, whose analysis was relied upon by the Essential Services Commission in 2008 when it concluded that an equity beta of 0.8 would be applied to gas distribution businesses, recognised that when this analysis had been done, the measurement period was one of unusually low volatility and this depressed the beta estimates.[40] It concluded that on the basis of the empirical estimates available at the time of the AER's review, there was no persuasive evidence to depart from an equity beta of one.

6.6.2 First principles analysis

The APA Group notes that in the key regulatory decisions made in relation to gas in recent years, including the ESC's 2008 decision and more recent AER decisions, there has been very limited (if any) consideration of the key factors that will influence the firm's systematic risk. Instead, reliance has been placed on the empirical analysis, noting the concerns that have been raised regarding the potential for estimation error, as highlighted above.

Synergies undertook a detailed first principles analysis as part of its assessment (refer Section 6). While the first principles analysis is qualitative only, it can be used to inform what the systematic risk profile of APT Allgas might be relative to the average gas distribution business, or the 'benchmark' firm. The analysis considers: the nature of the product or service, the nature of the customer, pricing structure, duration of contracts, market power, nature of regulation, growth options and operating leverage.

This analysis highlighted some key differences between APT Allgas' risk profile relative to gas distribution businesses in other states and considered the extent to which these risks are systematic in nature. It also highlighted some fundamental differences between gas and electricity distribution, which had been previously identified by the QCA. The most significant difference is the extent to that gas is a 'fuel of choice' and is therefore exposed to competition from alternative energy sources, including (but not limited to) electricity, which is a 'fuel of necessity'.

In relation to residential demand, this competition is particularly intense in Queensland, where gas has a relatively low penetration compared to the other states (it is used in only 12.5% of dwellings in Queensland in 2008, compared to 38% in New South Wales, 81% in Victoria, 56% in South Australia and 68% in Western Australia[41]). This in turn highlights that APT Allgas has very limited market power in the Queensland market. This market power will be lower than networks where gas naturally has a higher penetration, and much lower than electricity, which is naturally connected to every building. The existence of market power is a

[40] The Allen Consulting Group (2008). Beta for Regulated Electricity Transmission and Distribution, Report to Energy Networks Association, Grid Australia and APIA, September.

[41] Australian Bureau of Statistics (2008). Environmental Issues: Energy Use and Conservation, Catalogue 4602.0.55.001 Table 3.5.

standard assumption for natural monopoly infrastructure businesses and is generally seen as reducing systematic risk relative to businesses that do not have market power.

The intensity of competition is not limited to the residential sector. For example, there remain significant industrial loads in Brisbane that would be able to use natural gas that continue to source their energy from coal.

Hence, while over 60% of APT Allgas' revenue comes from commercial and industrial customers, whose demand will be more sensitive to movements in the general economy, the limited market power that it has in the residential sector also increases its systematic risk in this sector compared to other gas distribution network businesses operating in markets where gas has a much higher penetration. Overall, this presents a higher systematic risk profile for APT Allgas compared to other gas networks and certainly compared to electricity.

In summary, Synergies' analysis concludes the following.

- the demand for gas for residential use has some relationship with domestic economic activity, because:
  - the demand for gas has a positive income elasticity of demand;
  - APT Allgas' key growth market is new housing developments, which are positively correlated with domestic economic activity;
  - APT Allgas faces strong competition from substitutes in all of the applications for which gas is used, in particular, the competition that it is exposed to from solar energy (and to a lesser extent, heat pump technology) in the water heating market, which is its largest potential market in the residential sector. Queensland has one of the lowest penetrations of gas in dwellings of any Australian state. While a number of the factors that influence the choice of energy source are not related to the domestic economy (such as government policy initiatives), what is relevant to this assessment is that:
    - to the extent that demand has a relationship with domestic economic activity (via income and new dwelling construction activity), gas is exposed to higher market risk because it is a 'fuel of choice' relative to electricity, which increases the sensitivity of the firm's revenues to domestic economic activity (costs are considered separately below);
    - more importantly, this significantly reduces its market power, which is examined separately below;
- industrial and commercial demand will generally be more sensitive to economic activity. Industrial demand accounts for a relatively higher proportion of the demand for gas in Queensland relative to the other States and over 60% of APT Allgas' total revenue. This suggests higher exposure to systematic risk;

- a reasonable proportion of revenues vary with throughput (over 50% in the Volume Class, which accounts for over 70% of revenue), while the majority of its cost base is fixed. This provides some protection from systematic risk however it still leaves the balance of this revenue exposed to changes in volumes;

- there is no additional protection for revenues from industrial customers via term contracts, with only one industrial customer currently subject to a contract. Residential and commercial volumes are delivered via a Use of System Agreement with the retailer. Users can disconnect at any time under this arrangement;

- the impact of form of regulation also needs to be considered. It is recognised that while the implications of this for beta have generally seen to be unclear, the reality is that:

  - APT Allgas is exposed to higher volume risk under a price cap. For example, it is estimated that over the last access arrangement period, because actual volumes were lower than the forecast approved by the QCA the loss in revenue was in the order of $12.8 million;

  - it has been established that this volume risk is systematic in nature;

  - demand and costs are not related;

- while the existence of market power is often seen to have a dampening effect on the beta of a regulated infrastructure provider, this is not seen to be the case here because of the strong competition gas faces from substitutes, particularly in the residential sector in Queensland where it has a lower penetration relative to most of the other states. As outlined above, this is considered to be one of the key factors in determining APT Allgas' beta and a strong differentiator between it and other gas distribution firms, as well as electricity;

- the impact of growth options on beta is not considered to be material here;

- APT Allgas has high operating leverage, which is a significant contributor to systematic risk. However, there is no evidence to suggest that it is different from other comparable businesses, provided their activities are mainly focused in gas distribution. What it does do is magnify the impact of APT Allgas' exposure to market risk on the firm's returns.

6.6.3 Conclusions: equity beta

In conclusion, there are some fundamental differences between gas and electricity network businesses and between APT Allgas and other gas distribution networks in Australia. The key differences that are relevant to systematic risk are:

- industrial and commercial customers account for a much higher proportion of APT Allgas' total volumes compared to the other states where gas penetration in the residential sector is much higher. Revenue from these customers represents of 60% of APT Allgas' total revenue. In general, industrial and commercial demand will have a higher correlation with economic activity;

- gas is a 'fuel of choice' compared to electricity, which is connected to every building. The exposure to competition from substitutes dilutes market power, with market power generally seen as reducing a firm's exposure to systematic risk. In the residential sector, this dilution is exacerbated in the case of APT Allgas relative to the other states because gas has a much lower penetration in households.

Synergies concluded that with a starting point of an equity beta of one for the 'average' gas distribution business in Australia, an equity beta above one is appropriate for APT Allgas given these differences. It considers that an equity beta of 1.1 remains the most appropriate estimate for APT Allgas in the circumstances, which is consistent with the conclusion made by the QCA in 2006.

The QCA's assessment recognised the difference between the APT Allgas network and other distribution networks in Australia, in particular, its higher exposure to industrial demand. It also recognised the differences between gas and electricity networks and the former's greater competition from substitutes.

It is concluded that there is no persuasive evidence to depart from this estimate and an equity beta of 1.1 for APT Allgas is therefore proposed.

6.7 Gamma

Gamma is another key area that is particularly vulnerable to estimation error. The AER's decision to apply a gamma of 0.65 was arguably the most contentious area in the development of its WACC Statements. It is noted that a number of businesses have subsequently sought to depart from this assumption and that a number of merits review applications have been submitted on this matter. The APA Group acknowledges that the outcome of these appeals will be the key driver of future decisions in relation to gamma.

The Synergies Report summarises the key issues of contention in relation to gamma (refer section 7). Noting that extensive submissions have already been made on in relation to gamma, the key issues include:

- the AER's retention of a 100% distribution rate, which in turn implies that credits that are retained within the firm are fully valued. The Synergies Report identifies a number of issues with the rationale underpinning this assumption, including the AER's conclusion that such an assumption is consistent with the Officer model;

- the sole reliance on the Beggs and Skeels (2006) study as the only market-based study that seeks to value franking credits (or theta). The Synergies Report observes the considerable focus that has been placed on the SFG Consulting (SFG) study, which subsequently extended and enhanced this analysis, but has been consistently rejected by the AER. The AER has subjected the Beggs and Skeels study to nowhere near the same level of scrutiny (noting that its dataset has not been made available), with its own consultant noting that such scrutiny "would yield a list of questions and clarifications"[42];

- the AER's conclusion that only post-2000 data can be relied upon, which in turn is based on the evidence provided in the Beggs and Skeels study. It has already been shown that this evidence is not sufficiently reliable to enable it to be confidently concluded that there has been a structural break[43];

- the AER's continued reliance on the Handley and Maheswaran (2008) tax statistics analysis despite Synergies' assertion that such analysis cannot be used to value theta.

One of the main concerns with the AER's assessment of gamma is that it does not give due regard to the asymmetric consequences of error. It has applied a material increase in the gamma parameter (relative to the precedent value of 0.5) based on evidence that has been widely scrutinised and criticised.

Its response to concerns regarding the Beggs and Skeels study has not been to include other reputable Australian studies that have sought to estimate the value of gamma using market data, but instead to rely on one other study that uses a method that does not value gamma. The use of that study alone as the 'upper limit' is critical to the outcome as without it, the AER may have had no basis to depart from the precedent value of 0.5. It has also made a decision regarding the distribution rate that effectively attributes a 100% value to retained credits, which has no theoretical or empirical support.

The APA Group concurs with the view that a range of empirical evidence should be relied upon, however this evidence should be limited to market-based studies that can be used to estimate a value for franking credits. This evidence includes the following studies, as set out in the Synergies Report.

[42] M. McKenzie and G. Partington (2010). Report to AER: Evidence and Submissions on Gamma, 25 March, p.33.

[43] SFG Consulting (2009). The Value of Imputation Credits as Implied by the Methodology of Beggs and Skeels (2006), Report Prepared for ENA, APIA and Grid Australia, February; Synergies Economic Consulting (2009). Peer Review of SFG Consulting Reports on Gamma, A Report to the ENA, APIA and Grid Australia, January.

Table 6.1: Studies that can be referenced in valuing theta

Study	Methodology	Time Period for Estimation	Value of franking credits (V)
Hathaway and Officer (2004)[a]	Dividend drop-off	1988-2002	0.5
Bellamy & Gray (2004)[b]	Dividend drop-off (adjusted)	1995-2002	0
Cannavan, Finn & Gray (2004)[c]	Analysis of futures and physical market (no arbitrage framework)	Pre-45 day rule (1997)	Up to 0.5 (high-yielding stocks)
Beggs & Skeels (2006)[d]	Dividend drop-off	1986-1988 1989-1990 1991 1992-1997 1998-1999 2000 2001-2004	0.75 0.45 0.38 0.2 0.42 0.128 0.57
SFG Consulting (2010)[e]	Dividend drop-off, based on Beggs & Skeels methodology	1 Jul 97-30 Jun 99 1 Jul 99 -30 Jun 00 1 Jul 00-30 Jun 06	0.24 0.36 0.23
Feuerherdt, Gray and Hall (2010)[f]	Dividend drop-off, hybrid securities	Pre-1997 (45 day rule) Post 1997 – 2000 Post 2000	0

a N. Hathaway and R. Officer (2004).The Value of Imputation Tax Credits: Update 2004, Unpublished Working Paper, Capital Research Pty Ltd.

b D. Bellamy & S. Gray (2004). Using Stock Price Changes to Estimate the Value of Dividend Franking Credits, Working Paper, University of Queensland.

c D. Cannavan, F. Finn and S. Gray (2004). The Valuation of Dividend Imputation Tax Credits in Australia. Journal of Financial Economics, 73, 167-197.

d D. Beggs & C. Skeels (2006). Market Arbitrage of Cash Dividends and Franking Credits. Economic Record, 82, 239–252.

e SFG Consulting (2010). Further Analysis in Response to AER Draft Determination in Relation to Gamma, Prepared for ETSA Utilities, February.

f C. Feuerherdt, S. Gray and J. Hall (2010). The Value of Imputation Tax Credits on Australian Hybrid Securities, International Review of Finance, 10:3, 365-401.

This evidence shows that zero should at least be included within the bounds of a reasonable range. Excluding the Beggs and Skeels estimate for the 1986-88 sub-period, the highest value for theta is 0.57 (which is the number relied upon by the AER). This is considered a reasonable ‘upper bound’. Applying a distribution rate of 100% results in an upper bound of 0.4.

Based on the recommendations contained in the Synergies Report, the APA Group proposes:

- a distribution rate of 70%, consistent with what is readily observed in practice
- a range for theta of 0 to 0.57, reflecting the inherent uncertainty associated with estimating theta and the range of evidence available to inform it.

This results in a range for gamma of zero to 0.4. The mid-point of this range is 0.2. At worst, if the AER continues to exclude the evidence provided above, there is no persuasive evidence to depart from the precedent value of 0.5. However, if due consideration is given to this other evidence, and noting the problems that have been identified with the AER's assessment, the 'best estimate' is more likely to be below 0.5. APT Allgas has therefore proposed a gamma of 0.2.

6.8 Taxation rate

A corporate tax rate of 30% has been applied, consistent with regulatory practice.

6.9 Inflation

The APA Group notes the approach that the AER has applied to estimate inflation, which has been to estimate a ten year forward-looking average, assuming the Reserve Bank's most recent forecasts for inflation for the first two years and 2.5% after that.

The APA Group's view is that 2.5% is the most appropriate estimate where a long-term, forward-looking estimate is required. This is because the Reserve Bank's target band for inflation is between 2 and 3%, and it has demonstrated a clear and consistent intention to maintain inflation within this band via monetary policy. Such an assumption eliminates the need for any debate regarding forecasts (which remain highly uncertain), provides regulatory certainty, and is considered reasonable and plausible.

The APA Group also notes comments that the AER has previously made regarding the Commonwealth Government's decision to re-commence the issuance of indexed bonds (which have previously been used to derive an inflation estimate). If the AER reconsiders the use of such an approach, it is imperative that it can be demonstrated that the estimate is reliable and robust. This in turn requires being able to be satisfied that there is sufficient liquidity in the indexed bond market for these estimates to be yielding any (potentially) reliable information regarding inflationary expectations. Given the liquidity problems that existed when these bonds were trading in the market, this is expected to remain a significant issue in the future.

6.10 Debt raising costs

The APA Group has proposed to apply the method and table of estimates used by the AER, as recently published in its decision for the Jemena Gas Networks.[44] Based on its opening RAB of $396.2 million, and applying a 60% gearing ratio, its

[44] Australian Energy Regulator (2010c). Jemena Gas Networks, Access Arrangement Proposal for the NSW Gas Networks, 1 July 2010 – 30 June 2015, June, p.278.

total debt will be in the order of $240 million. Reference is therefore made to the indicative allowance for one bond issue in the AER's table, which is 10.8 basis points per annum.

Debt raising costs of 10.8 basis points per annum is therefore proposed.

6.11 WACC estimate

Based on the parameter estimates set out above, the resulting indicative estimate for WACC is summarised in the following table.

Parameter	Estimate
Risk-free rate	5.07%
Debt to value	60%
Debt margin	3.85%
Debt raising costs	0.108%
MRP	6.5%
Gamma	0.2
Equity beta	1.1
Cost of equity	12.22%
Cost of debt	9.03%
Post tax nominal vanilla WACC	**10.30%**

The Synergies Report examines the reasonableness of the cost of debt and equity based on the analysis referred to in section 6.1.2 above (refer sections 4 and 8 of the Synergies Report).

Based on that analysis, if regard is given to the average cost of debt and equity prevailing since 1990, the difference between the cost of debt and equity should be between 4.5% and 6%. This is considered conservative because 6% is the average difference observed prior to the crisis, whereas the 4.5% partially reflects the compression in returns experienced following the crisis.

The difference implied by the above estimates is only 3.19%. As the cost of debt is estimated based on current market data, whereas the cost of equity is more reflective of a long term average (with the exception of the risk-free rate), the risk for the APA Group is that the return on equity will provide equity investors with inadequate compensation for the risks they bear in the market environment that is expected to prevail over the course of the regulatory control period.

Overall, the key issue that has been identified for APT Allgas is the beta estimate. It has been concluded that the most reasonable estimate to apply in the current circumstances is 1.1, which is consistent with the value that was previously applied by the QCA and reflects some fundamental differences in the systematic risk profile between the APT Allgas network and the gas distribution networks in the other states, as well as differences between gas and electricity network businesses. The two key differences identified is APT Allgas' higher exposure to demand from industrial and commercial customers, and its lack of market power given the competition to which gas is exposed in the Queensland market.

Based on the parameter estimates applied above, if the AER applied an equity beta of 0.8 (as it did in the Jemena Gas Networks decision) the difference between the cost of equity and the cost of debt would only be 1.24%. Such a significant contraction in the return required by equity holders relative to debt holders is neither reasonable nor plausible, especially in the current market environment. Apart from the concerns that have been expressed with the beta assessment previously undertaken by the AER for electricity networks, and the need to have regard to the specifics of the systematic risk profile of the APT Allgas network, this would risk materially under-compensating equity providers. This could adversely impact the ability to fund its investments.

The APA Group has therefore applied a post-tax nominal WACC of 10.3% for the purpose of setting its indicative tariffs in this regulatory proposal.

7 Taxation

This section addresses the requirement of rule 72(1)(h) for the access arrangement information to include “the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated”.

Rule 76(c) allows an estimate of corporate income tax to form a building block for a distribution business’ total revenue requirement. APT Allgas is proposing that the access arrangement period should be modelled using a post-tax framework. This requires APT Allgas to establish a tax asset base (TAB) consistent with Rule 76(c).

The estimated cost of corporate income tax for each regulatory year (ETC_t) is calculated 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 regulatory year t that would be earned by a benchmark efficient entity as a result of the provision of regulated services if such an entity, rather than the service provider, operated the business of the service provider, such estimate being determined in accordance with the AER’s post-tax revenue model

r_t is the expected statutory income tax rate for that regulatory year assumed to be 30 per cent

γ (gamma, the assumed utilisation of imputation credits) is deemed to be 0.2

The estimate must take into account the depreciation of the TAB for tax purposes.

Under the post-tax approach previously approved by the QCA and applying to APT Allgas in the earlier access arrangement period, the allowance for tax depreciation was made to equal that of the regulatory depreciation. Therefore there was no requirement to establish a TAB under the last regulatory reset process. Under the proposed transition to a post-tax revenue model, APT Allgas must establish a TAB. APT Allgas notes that the NGR do not specify how the TAB should be estimated.

7.1 *Estimation of a tax asset base*

In June 2007, the AER released an issues paper titled *Transition of energy businesses from pre-tax to post-tax regulation*, [45] which proposes an approach by

[45] This Issues Paper is Appendix A to AER, *Final decision - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-14 Post-tax revenue model*, January 2008. http://www.aer.gov.au/content/item.phtml?itemId=717303&nodeId=6642a45c2405e27a744f1cb974919

which the TAB could be established for the transition to post-tax regulation. APT Allgas further notes the AER's statement in the issues paper that "there may be a degree of judgement required in establishing the initial tax base". The AER advised that it would work with the electricity DNSPs to determine the appropriate opening value of the TAB.[46]

7.1.1 Approach - precedent

In recent regulatory proposals, there has been a variety of approaches to determining the Tax Asset Base.

7.1.1.1 Energex

Energex calculated its TAB based on its most recently filed National Tax Equivalent Regime (NTER) tax return. This approach was reviewed by the AER's consultant, McGrathNicol, who found that this methodology appeared reasonable:[47]

> McGrathNicol found that, based on the information provided, Energex's proposed methodology for calculation of its tax asset base appeared reasonable. McGrathNicol also noted that tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.
>
> In summary, McGrathNicol noted that Energex:
>
> - established its opening asset base using the most recent NTER tax return to the ATO (year ending 30 June 2008)
> - determined a tax asset base applying written down values
> - derived tax asset values from asset registers, tax working papers and other supporting documentation and that the standard tax and remaining tax life inputs to the PTRM were consistent with relevant source material
> - treated past additions based on actual capex in a manner consistent with generally accepted accounting principles
> - included capital contributions in its tax asset base and treated depreciation on contributed assets consistent with standard control services

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908&fn=Final%20decision%E2%80%94ACT%20and%20NSW%20post-tax%20revenue%20model%20(January%202008).pdf

[46] AER, *Final decision - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-14 Post-tax revenue model*, January 2008. .p

[47] AER, *Draft decision Queensland Draft distribution determination 2010–11 to 2014–15*, 25 November 2009 and McGrathNicol, *Assessment of Energex's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 23 September 2009).

- had applied an appropriate method to separate RAB and non-RAB components
- had appropriately not included work in progress in its opening tax asset base for the next regulatory control period.

The AER accepted Energex' approach, noting "based on the findings of McGrathNicol, the AER considers that the tax inputs into the Qld DNSPs' PTRM and RFM are consistent with the tax provisions of the NER." (page 218)

7.1.1.2 Ergon Energy

Ergon Energy applied a similar approach, but used 2005 as the starting point. Similarly, McGrathNicol found the approach to be reasonable:[48]

> McGrathNicol found that, based on the information provided, Ergon Energy's proposed methodology for calculation of its tax asset base appeared reasonable. McGrathNicol also noted that tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.
>
> In summary, McGrathNicol noted that Ergon Energy:
>
> - had established its opening tax asset base using the RAB as at 1 July 2005. This was considered appropriate because it represented the start of the current regulatory control period and that a separate tax asset register had been maintained where these assets (and additions) had been depreciated at the tax depreciation rates set by the ATO
> - had proposed a tax asset base that was significantly higher than the base contained in its ATO NTER asset valuation. This was considered appropriate because the higher tax asset base included costs (such as labour costs and overheads associated with the construction of network assets) that should be reflected in capex if network assets are to be fully costed
> - derived tax asset values from asset registers, tax working papers and other supporting documentation and that the standard tax and remaining tax life inputs to the PTRM were consistent with relevant source material
> - treated past additions based on actual capex in a manner consistent with generally accepted accounting principles
> - included capital contributions in its tax asset base and treated depreciation on contributed assets consistent with standard control services

[48] *Draft decision - Queensland Draft distribution determination 2010–11 to 2014–15*, 25 November 2009 and McGrathNicol, *Assessment of Ergon Energy's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 29 September 2009.

- had applied an appropriate method to separate RAB and non–RAB components
- had appropriately not included work in progress in its opening tax asset base for the next regulatory control period.

7.1.1.3 ETSA Utilities

In contrast, ETSA Utilities established its TAB starting from the time it first became regulated in 1999, and rolled forward the TAB from that point, using actual capex and the maximum allowable amount of tax depreciation. Again, the AER's consultant, McGrathNicol, found this approach to be reasonable:[49]

> McGrathNicol found that, based on the information provided, ETSA Utilities' proposed methodology for calculation of its tax asset base appeared reasonable. McGrathNicol also noted that ETSA Utilities' tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.
>
> In summary, McGrathNicol noted that ETSA Utilities:
>
> - established its opening asset base using the commencement date of 11 October 1999
> - applied a straight–line method of depreciation to value its tax asset base as at 30 June 2010
> - applied the depreciated value of distribution network assets acquired before the date of regulation to be incorporated into the tax asset base as at 1 July 2010
> - determined forecast depreciation at an asset category level using straight–line depreciation with all assets within each class assigned weighted average standard and remaining lives
> - did not include shorter life asset acquisitions and disposals in the calculation of its tax asset base prior to 1998
> - relied on historical balance sheet movements to determine asset acquisitions and disposals between 1 February 1992 and 28 January 2000

[49] *Draft decision - South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009 and McGrathNicol, *Assessment of ETSA's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 2 October 2009.

- included capital contributions for the purposes of the tax asset base, allocated them to a single asset category and depreciated them based on the weighted average life of the assets for which the contributions were received
- included work in progress in the tax asset base as a one-off transitional measure
- applied an appropriate method to separate RAB and non–RAB components.

7.1.1.4 ActewAGL

In calculating its TAB, ActewAGL used the tax values dating back from the time it first became subject to the National Tax Equivalent Regime (NTER):[50]

> ActewAGL used a pre-taxation framework in the previous access arrangement period. In order to transition to a post-taxation framework it is necessary to estimate the value of the taxation asset base as at the commencement of the access arrangement period. To estimate the taxation value of the capital base, ActewAGL has used actual taxation asset values as at the date on which it first came under the national taxation equivalent regime (NTER), 1 July 2001, and has rolled this taxation asset base forward to 30 June 2010 using actual and forecast capital expenditure, capital contributions, disposals and taxation depreciation. …
>
> Taxation depreciation is estimated by ActewAGL using the PTRM based on ActewAGL's proposed remaining lives, standard lives, asset base and capital expenditure relevant for taxation purposes. The AER has reviewed and considers that ActewAGL's proposed taxation values for remaining lives, standard lives and the asset base are reasonable.

In summary, all these approaches to establishing the TAB appeared to be acceptable to the AER. This is consistent with the AER's comments in its *Final decision - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-14 Post-tax revenue model*, January 2008 that "[t]he AER will work with the DNSPs to ensure that the tax asset values on commencement of the post-tax approach are reasonable and appropriately substantiated" (page 9).

[50] AER, *Draft decision – ActewAGL Access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010 – 30 June 2015*, November 2009. The AER required an amendment to the AA Proposal to reflect a discrepancy in the standard life of high pressure services. The required amendment related to this standard life rather than the approach to setting the Tax Asset base.

7.1.2 APT Allgas Approach

APT Allgas has calculated its Tax Asset Base in a manner consistent with the guidelines set out by the AER's June 2007 *Transition of energy businesses from pre-tax to post-tax regulation* released issues paper, in particular by:

- establishing its opening tax asset base by reconstructing the APT Allgas tax base as at 30 June 2001;
- using the opening tax values as at 30 June 2001; APT Allgas has utilised the NTER values associated with the Allgas entity;
- determining a tax asset base applying tax rates to the written down values using the diminishing value method;
- deriving tax asset values from asset registers, tax working papers and other supporting documentation and ensuring that the standard tax and remaining tax life inputs to the PTRM were consistent with relevant source material;
- treating past additions based on actual capex in a manner consistent with generally accepted accounting principles;[51]
- adding additions to the TAB using the same rates and maturity profiles as actual additions to the APT Allgas TAB;
- including capital contributions in its tax asset base, net of contributions, and treated depreciation on contributed assets consistent with other distribution assets;
- adjusting for disposals in line with regulatory financial statements;
- has applied an appropriate method to separate RAB and non-RAB components; and
- has appropriately not included work in progress derived from the audited regulatory financial statements in it's opening tax asset base for the next regulatory control period.

This process has been reviewed by Deloitte, whose opinion is attached as Attachment 7.1.

APT Allgas submits that it is not appropriate to use the consolidated APA Group TAB as a base for the APT Allgas regulatory TAB. APT Allgas Tax registers now in place have been adjusted to reflect the allocable costs amount, as restricted by the requirements of Division 58 of the *Income Tax Assessment Act*, upon entering the

[51] As the Allgas cost allocation and capitalisation methodology was developed during its ownership by Energex, APT Allgas has applied the same methodology adopted by Energex.

APA Group tax group, in addition to any tax consolidation entries made to the Allgas tax register as a consequence of entry to the Energex tax group on 1 Dec 2002. As indicated in the AER guidelines the entity should account for tax on a stand alone basis.

The value of additions to the statutory TAB, in the time since acquisition for the Allgas entity by APA Group, are based on the statutory accounts and not the value of the additions for regulatory purposes. There are significant differences in treatments of assets for regulatory and income tax purposes making the value of the existing APT Allgas actual TAB inappropriate to use as the regulatory TAB.

In order to estimate the TAB, the Allgas tax asset register as at 30 November 2002, prior to entry into the Energex tax group, has been rolled back to 30 June 2001 to reflect the commencement of the post tax regulatory regime in which Allgas then operated. Notwithstanding that the tax deprecation for the previous AA period was aligned to regulatory depreciation, tax deprecation has been rolled forward to 30 June 2011 using capital additions net of contributions, disposals and recognising WIP movements.

The AER's approach to setting the TAB requires an assessment of the tax value of assets at the date APT Allgas was first subject to tax or the NTER. In the absence of detailed contemporaneous tax records from Energex, the previous owners, the exact details of the asset value at the time of the establishment of the NTER value are not known. However it is possible to reconstruct the tax cost base as at 30 June 2011 by reference to the tax asset register as at 30 November 2002, together with the tax register provided to APA dated 31 October 2006, and details from the tax register since 1 November 2006. This is achieved by utilising the date in service and applying appropriate tax rates to roll back the Allgas TAB to 1 July 2001.

From 1 July 2002 the ATO provides for a statutory life cap for gas distribution assets reducing the effective life of gas distribution assets, which the Commissioner for Taxation recommended be amended from previous asset lives (some over 50 years) to 20 years.[52] The Allgas tax register did not reflect these rates, and amendments were made for the life of these assets for assets acquired post 1 July 2002. An efficient business would depreciate the assets for tax in most circumstances as quickly as allowable and therefore APT Allgas has prepared the roll forward TAB on that basis.

All assets acquired pre 1 July 2002 have the tax rate attributed by Allgas at the time on the basis that Allgas could identify the appropriate rates to use which, from the lack of detailed narrative associated to each entry and the disconnect that exists between the Allgas tax register and the Allgas fixed asset register, would make it impossible to reconstruct with a higher degree of accuracy.

[52] See ATO, Capital allowances: legislative caps on effective life of oil and gas related assets at http://www.ato.gov.au/businesses/content.asp?doc=/content/30407.htm

The additions have been added to the regulatory tax register based on the actual date in service profile. APT Allgas assets acquired between December 2006 and 30 June 2007 were all added to both the fixed asset and tax asset registers with date in service from 1 July 2008 making it difficult to establish the specific age profile of these asset additions. The timeframes which those assets have been added to the register have been estimated on the assumption asset additions were made evenly over the period 2007-2008.

The actual assets disposed of are not readily identifiable in the TAB and an approach has been adopted to adjust the TAB by the value of the written down value of disposed assets which ensures that APA do not claim tax depreciation on assets disposed of going forward.

7.2 Standard tax lives of assets

Table 7.1 sets out the asset class Standard life (years) or ATO statutory cap that has been used in preparing the APT Allgas TAB:

Table 7.1 Historical and statutory tax asset lives

Category	Life (Years)	Statutory Cap (Years)	Remaining Life
TRS & DRS - Valves & Regulators	40	20	15.7
HP Steel Mains and services	50	20	9.2
Distribution Mains and services	50	20	8.1
Meters - Tariff	15	n/a	6.1
IT Systems	2.5	n/a	0.1
Land and Building	25	n/a	18.7

7.3 Tax Asset Base Roll Forward 2001-2010

Allgas' TAB was $46.8m as at 1 July 2001. The value of these assets includes assets in the divisional tax asset register for gas distribution. Table 7.2 provides a breakdown of opening tax asset values for each category of assets in the TAB.

APT Allgas has rolled forward its tax asset base from 1 July 2001 to 30 June 2010 using actual and forecast capital expenditure, capital contributions and disposals consistent with the roll forward of the capital. All conforming capital expenditure that contributes to the forecast capital asset base has been incorporated into the roll forward of the tax asset base. In line with the treatment in the capital base, corporate assets are not included in the APT Allgas tax asset base.

Depreciation has been calculated on a diminishing value basis with the determined methodology for APT Allgas tax asset base. The diminishing value method results in significantly higher depreciation rates for relatively new assets this is further exacerbated by the TAB statutory cap ruling on tax assets.

APT Allgas submits a TAB value of $113.0m (nominal) for the start of the 2011-16 regulatory period as demonstrated in Table 7.2.

Table 7.2 Roll forward of the TAB from 2001/02 to 2010/11

$m	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Opening TAB	46.8	52.9	54.2	55.2	61.4	70.2	88.9	88.4	97.6	104.9
Capital expenditure	17.8	11.0	8.2	14.5	17.9	28.4	12.5	21.4	18.8	18.9
Depreciation	11.7	9.7	7.2	8.3	9.0	9.7	13.1	12.2	11.4	10.8
Closing TAB	**52.9**	**54.2**	**55.2**	**61.4**	**70.2**	**88.9**	**88.4**	**97.6**	**104.9**	**113.0**

Table may not add due to rounding

7.3.1 Tax Asset Base Roll Forward 2010 to 2015

Consistent with the roll forward of APT Allgas' capital base from 1 July 2011 to 30 June 2016, APT Allgas proposes to adopt tax asset base roll forward schedule that has been calculated using forecast capital expenditure. Similarly, APT Allgas proposes that the depreciation schedule for establishing the opening tax asset base at 1 July 2015 will be based on forecast capital expenditure as demonstrated in Table 10.9.

Table 7-3 Roll forward of the TAB from 2010/11 to 2015/16

$m (nominal)	2011/12	2012/13	2013/14	2014/15	2015/16
Opening TAB	112,952	124,137	134,889	146,237	156,514
Forecast capital expenditure	25,794	25,836	28,259	28,977	30,183
Straight-line depreciation	14,608	15,084	16,912	18,700	19,388
Closing TAB	**124,137**	**134,889**	**146,237**	**156,514**	**167,310**

7.3.2 Corporate income tax building block

Consistent with rule 76 (c), APT Allgas proposes a corporate income tax building block as set out in Table 7-4.

Table 7-4 Corporate income tax building block 2011/12 to 2015/16

$m (nominal)	2011/12	2012/13	2013/14	2014/15	2015/16
Tax Allowance	2,499	2,441	2,238	2,094	2,456

7.4 Tax Losses

Allgas has modelled the regulatory tax position for the period from 1 July 2001 to 30 June 2010 in a manner that is consistent with the AER's post-tax revenue model for distribution businesses to determine the potential tax losses that are attributable in that period. This modelling confirms that there are no tax losses attributable which should be carried forward at 30 June 2010.

8 Operating expenditure

8.1 Historical operating expenditure 2006-11 AA Period

This Section of the Access Arrangement Submission describes APT Allgas' historical non-capital costs during the current Access Arrangement period (2006-11 AA period). This information is provided in accordance with Rule 72(1)(a)(ii).

Rule 69 of the National Gas Rules defines operating expenditure for the purpose of price and revenue regulation as "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".

In addition, Section 24 of the National Gas Law states that "A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—

(a) Providing reference services; and

(b) Complying with a regulatory obligation or requirement or making a regulatory payment."

For the purpose of this Access Arrangement Submission, non-capital expenditure has been divided into controllable costs and non-controllable costs. These are described below.

8.1.1 Controllable Costs

Controllable costs are those costs incurred by APT Allgas in the operation of its gas distribution network, over which APT Allgas is able to exert a significant degree of influence in terms of both frequency and magnitude of the costs. However, limitations placed upon it by others in terms of prudency and efficiency, must also be considered by APT Allgas in controlling these costs. Typical controllable costs occur in the areas of maintenance and operation of the network, marketing, administration and strategic planning.

Operating and Maintenance

Operating and Maintenance costs include costs associated with recurring activities associated with inspection, planned and unplanned maintenance, and operation of the APT Allgas distribution network. Typical operating and maintenance activities may include inspection activities such as patrolling and leakage surveying of the network, 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.

Operating and maintenance costs also include the costs of support activities such as procurement, stores, property, computing & communication, and operation of the APT Allgas vehicle fleet.

Network Development

The purpose of network development activity is to maximise utilisation of the natural gas distribution networks by increasing consumer numbers and average consumer consumption, thereby lowering the unit cost of delivered natural gas to the consumer by spreading fixed network operating costs over a larger consumer base.

Network development consists of customer service and representation (labour costs), and marketing and promotion programs. Labour costs include operation of the Natural Gas Hotline, and all tasks required to co-ordinate and process new network connection work orders, and maintain relationships with key customers and industry groups. This activity type is therefore essential to network operation and growth. Key marketing and promotion programs include advertising, direct communication and events based activities targeting specific customer segments crucial to long-term network growth, and performance based incentives designed to boost network connection numbers at strategic times.

Given the long term objectives of network development activities, the impact on network performance is expected to be reflected in business as usual network growth, with no significant measurable increases in the short term.

Administration and Strategic Planning

Administration and strategic planning costs are incurred as a result of local support activities which are necessarily incurred in operation of a business such as APT Allgas. They include administration, human resources, accounting and asset management and strategic planning costs.

8.1.2 Non-Controllable Costs

Non-controllable costs are those costs necessarily incurred by APT Allgas, but over which APT Allgas has little or no direct control. Non-controllable costs may include costs imposed by external regulatory bodies. Specifically, non-controllable costs include consumer service costs, unaccounted for gas (UAG), government taxes and levies, and costs of implementation of full retail contestability (FRC) in Queensland, and the corporate overheads allocated to APT Allgas by its parent company, APA Group (APA).

Consumer Services

Consumer services costs are predominantly associated with the provision of special meter reading services, market operation, and costs associated with consumer and public network enquiries.

Unaccounted for Gas

UAG is defined as the volume of gas injected into the distribution system less the volume of gas billed to the consumers. The difference is termed Unaccounted for Gas. UAG occurs for a variety of reasons. The two major contributors to UAG on the APT Allgas distribution network are leakage and metering errors. APT Allgas is required to compensate its major retailer for any UAG incurred.

Government Taxes and Levies

APT Allgas pays a variety of fees and charges to government bodies, including the Queensland Department of Mines and Energy (DME), Queensland Competition Authority (QCA), NSW Department of Water and Energy (DWE), and IPART in NSW. These fees and charges are set by the relevant government body, and are non-negotiable.

Contestability Costs

Contestability costs are costs associated with the imposition of FRC in Queensland. These costs are non-controllable. In the current Access Arrangement, contestability costs were separately identified and dealt with as "pass through" costs[53]. APT Allgas proposes to include FRC costs into the Access Arrangement as Operations and Maintenance costs, thereby treating them as a normal cost of doing business. These have therefore been re-identified for the purpose of this AA Submission as Metering and Billing costs.

Corporate overheads

Corporate overheads are those charges necessarily allocated to APT Allgas by its parent company APA Group to APT Allgas' share of the costs associated with management and administrative functions provided by APA .

8.1.3 Comparison between actual and QCA approved operating expenditure for the 2006-11 Access Arrangement period.

[53] Queensland Competition Authority, *Final Decision, APT Allgas FRC Cost Pass-through Application*, March 2009

APT Allgas' actual operating costs for 2006-11 AA period are shown in Table 8-1. shows the operating expenditure approved by the QCA in the 2006 Access Determination Final Approval[54].

Table 8-1 QCA Approved Expenditure 2006 -11 AA Period

($m nominal)	2006/07	2007/08	2008/09	2009/10	2010/11
Inspection	1.29	1.73	1.73	1.83	1.72
Planned Maintenance	3.04	3.03	3.00	2.67	2.82
Corrective Maintenance	2.52	2.46	2.34	2.03	1.87
Customer Service	0.99	0.99	1.08	1.17	1.25
Maintenance Planning & Support	2.48	2.27	2.35	2.33	2.32
Network Development	0.6	0.6	0.6	0.6	0.6
Ancillary Services	0.6	0.59	0.68	0.78	0.77
Total O&M Costs	**11.52**	**11.67**	**11.78**	**11.41**	**11.35**
UAG[55]	1.5	1.4	1.4	1.3	1.2
Contestability Costs[56]	1.12	2.23	1.67	1.70	1.75
Total Operating Costs	**14.14**	**15.31**	**14.85**	**14.41**	**14.31**

APT Allgas' actual operating costs for 2006-11 AA period are shown in Table 8-2. These costs are based on actual costs for financial years 2007 to 2010, and forecast costs for financial year 2011.

[54] Queensland Competition Authority, *Final Approval, Revised Access Arrangement for Gas Distribution Networks: Allgas Energy*, June 2006, Table 13.3

[55] Queensland Competition Authority, *Final Approval – Revised Access Arrangement for Gas Distribution Networks: Allgas Energy*, June 2006, Table 13.5

[56] Queensland Competition Authority, *Final Approval – APT Allgas FRC Cost Pass-Through Application*, March 2009, Table 6

Table 8-2 APT Allgas Actual/Forecast Operating Costs 2007 - 2011

($m nominal)	2006/07[57]	2007/08[58]	2008/09[59]	2009/10[60]	2010/11[61]
Inspection	0	1.24	0.70	0.77	0.81
Planned Maintenance	2.61	1.83	1.51	4.85	5.67
Corrective Maintenance	2.19	2.32	3.11	2.95	3.09
Customer Service	1.01	0.05	0.01	1.09	1.14
Maintenance Planning & Support	4.52	2.87	2.07	1.16	0.94
Network Development	0	1.91	1.42	0.00	0.00
Ancillary Services	0.93	0.57	1.02	0.64	0.30
Total O & M Costs	**11.27**	**10.78**	**9.83**	**11.46**	**11.95**
Administration	0.58	0.98	1.65	1.39	1.25
Marketing	0	0.64	1.60	1.31	1.05
UAG	1.88	1.96	2.26	2.18	2.44
Other	0.47	0.04	0	0.58	1.43
Total Operating Costs[6]	**14.19**	**14.40**	**15.34**	**16.92**	**18.12**

[57] APT Allgas Energy Pty Ltd ACN 009 656 446 *Regulatory Accounting Statement for the Financial Year Ended 30 June 2007*, Schedule D and Note 7

[58] APT Allgas Energy Pty Ltd ACN 009 656 446 *Regulatory Accounting Statement for the Financial Year Ended 30 June 2008*, Schedule D and Note 6

[59] APT Allgas Energy Pty Ltd ACN 009 656 446 *Regulatory Accounting Statement for the Financial Year Ended 30 June 2009*, Schedule D and Note 6

[60] APT Allgas Energy Pty Ltd ACN 009 656 446 *Regulatory Accounting Statement for the Financial Year Ended 30 June 2010*, Schedule D and Note 6

[61] Forecast

Several important points need to be made about APT Allgas' actual operating costs. They are:

- The categorisation of costs has changed significantly between the Final Decision for the 2006-11 Access Arrangement Submission, and the present. In November 2006, under instruction from the Queensland Government, the APT Allgas business was sold by its previous owner, Energex, to the APA Group. This meant a change from Energex accounting systems to APA accounting systems. The APA systems have different functionality to the Energex systems. This change makes it very difficult to present costs in the same format as previously.

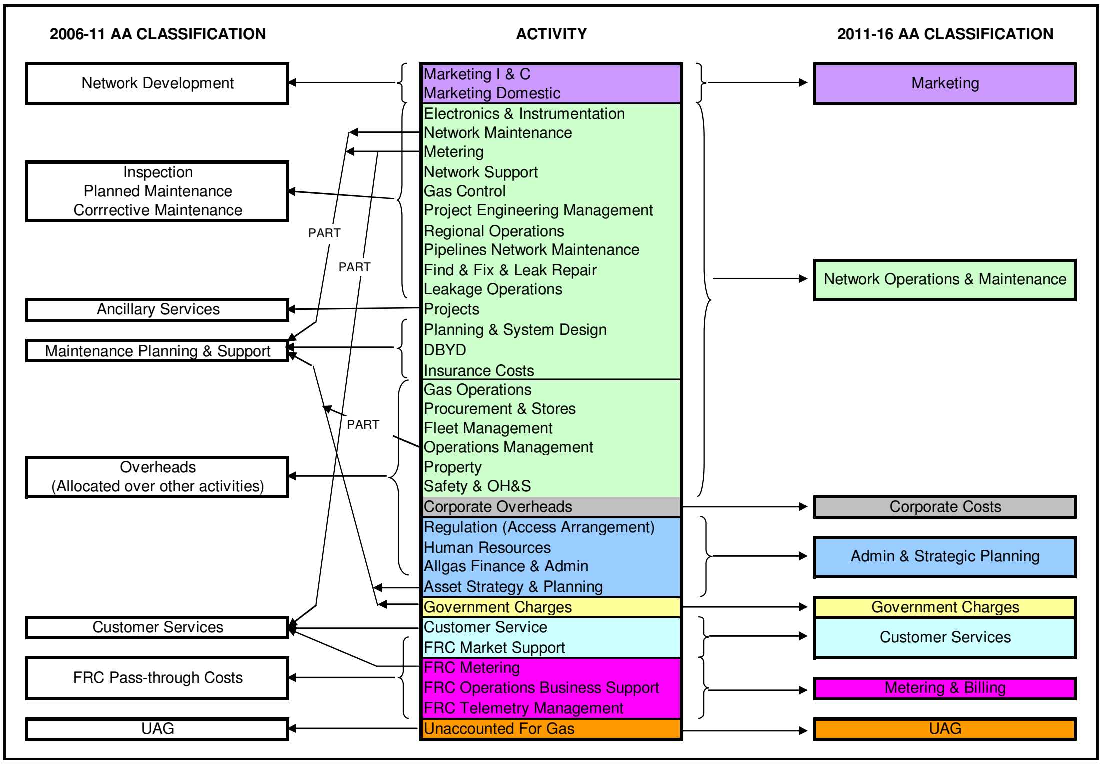
- The sale of APT Allgas to APA Group means that there is very limited historical data available to APA for the period prior to the sale, as all operating and financial systems were retained within Energex, and the APT Allgas business was forced to start afresh with new systems and processes.

- In addition to the change in ownership, APA changed the accounting systems for APT Allgas, this time from Finance 1 to Oracle, during the financial year 2010. This change was made to achieve common accounting systems and processes across APA's business Australia wide. This second change means that the APT Allgas accounts have now been through two major system changes. These changes make it very difficult to achieve consistency of presentation of financial data across the 2006-11 AA period.

- FRC costs are now considered by APT Allgas to be a normal part of operating in the Queensland gas distribution market. Any costs associated with contestability have therefore been renamed Metering and Billing costs. Metering and Billing costs are classified as non-controllable costs in this Access Arrangement Submission.

Figure 1, below, gives a pictorial representation of the changes in the categorisation of cost of activities between the 2006-11 and the 2011-16 AA periods.

Figure 8-1 Cost categorisation Changes between AA periods



These changes mean that for any meaningful comparison to be made, costs are better rolled up to a higher level than the previously utilised categories of inspection, planned maintenance, corrective maintenance, and maintenance planning & support.

In the interests of enhancing visibility, historical operating costs for the 2006-11 AA period have also been supplied in the same format as forecast operating costs in the 2011-16 AA period. However, the categorisation of historical operating costs in the forecast cost format is also somewhat tenuous, and should be regarded as indicative only.

Table 8-3 presents the variation in approved and actual operating costs for the 2006-11 AA period in the categories of network operations and maintenance, marketing, and UAG.

Table 8-3: Variations Between Actual and Approved Operating Costs

($m nominal)	2006/07	2007/08	2008/09	2009/10	2010/11[62]
Network O & M Actual[63]	12.3	9.9	10.1	13.4	14.6
Network O & M Approved	12.0	13.3	12.9	12.5	12.5
Network O & M Variance	(0.3)	3.4	2.8	(0.9)	(2.1)
Marketing Actual[64]	0	2.6	3.0	1.3	1.1
Marketing Approved	0.6	0.6	0.6	0.6	0.6
Marketing Variance	0.6	(2.0)	(2.4)	(0.7)	(0.5)
UAG Actual	1.9	2.0	2.3	2.2	2.4
UAG Approved	1.5	1.4	1.4	1.3	1.2
UAG Variance	(0.4)	(0.6)	(0.9)	(0.9)	(1.2)
Total Operating Actual	**14.2**	**14.4**	**15.3**	**16.9**	**18.1**
Total Operating Approved	**14.1**	**15.3**	**14.9**	**14.4**	**14.3**
Total Operating Variance	(0.1)	0.9	(0.4)	(2.5)	(3.8)

Major contributors to variances are identified below.

Network Operations and Maintenance

Change to AS4645 – Gas Distribution Networks

"The intent of this Standard is to provide for the protection of the general public, gas distribution network operating personnel and the environment, and to ensure safe and reliable operation of gas distribution networks that reticulate gas to consumers.

[62] Forecast

[63] Includes costs of Inspection, Planned Maintenance, Corrective Maintenance, Customer Service, Maintenance Planning & Support, Ancillary Services, Administration, and Other

[64] Includes costs of Marketing and Network Development

This Standard achieves its purpose through six fundamental principles as follows:

- A gas distribution network shall be designed and constructed to have sufficient controls to withstand the threats to which it may be subjected during its life cycle.
- Before a gas distribution network is placed into operation it shall be inspected and tested to prove its integrity.
- Important matters relating to safety, engineering design, materials, testing and inspection shall be reviewed, documented, recorded and approved in accordance with the SAOP.
- Operations and maintenance shall provide for continued monitoring and safe operation of the gas distribution network.
- Where changes occur in or to a gas distribution network, which alter the design assumptions or affect the original integrity, appropriate steps shall be taken to assess the changes, to ensure continued safe operation of the network.
- Where means of compliance alternative to that provided in this Standard is to be adopted, a review shall be undertaken to determine the acceptability of the alternative. Subject to the criticality of the alternative means of compliance, this review may be undertaken by either an internal, or external, independent party."[65]

Much of the content of this revised standard is not new. However, a major change was included over the 2005 version of the Standard, namely the requirement for regular and frequent formal safety assessments (FSAs). This requirement now requires FSAs to be carried out more frequently than previously, when formal safety assessments were carried out only as part of the design process, or during MAOP reviews for steel pipelines. There is now a requirement to perform an FSA at multiple points in the life cycle of each asset, including the design, construction, testing, commissioning, maintenance and abandonment stages of each asset. There is also a requirement to continuously review each asset in terms of not only its condition and integrity but in relation to any changes to the environment within which it is installed.

This increased requirement for formal safety assessments is reflected in the 09/10 base year actual costs.

Marketing

There has been significant increase in marketing costs since APT Allgas was purchased by APA in November 2006. This increase is due to the increased role of network development and marketing activities under APA ownership.

[65] AS4645:2008 Gas Distribution Networks

APT Allgas was previously owned by Energex. Energex operated as two distinct companies, these being the distribution company and the retail company. Under this structure, all marketing activities were carried out by Energex Retail. Energex Distribution had no facility for marketing. In addition, gas was a minor business for Energex, compared to the dominant electrical business. APT Allgas was managed and operated as part of the Energex distribution business. Despite this, APT Allgas had its own, albeit small, marketing (network development) function. As part of Energex, APT Allgas' network development activities were focused around connection of new consumers to the APT Allgas distribution network. Strategic marketing of gas was not undertaken.

It is not possible to separately identify marketing costs for financial year 2007.

Unaccounted for gas

Table 8-4 below, shows the UAG approved in APT Allgas' 2006 Access Determination.

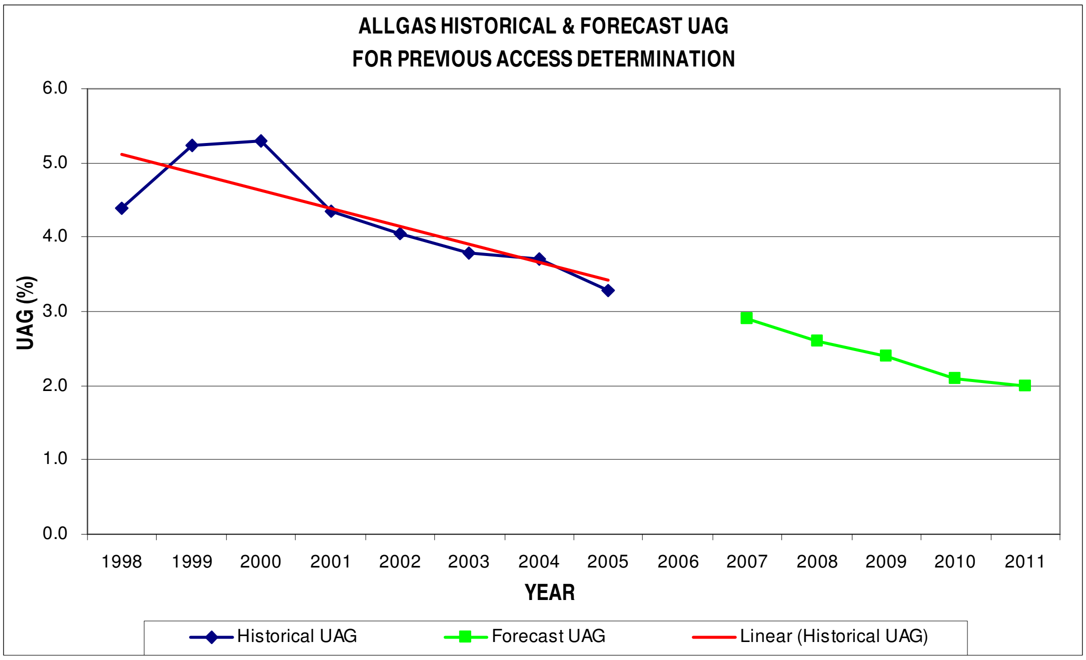
Table 8-4 Forecast UAG, 2007 - 2011

($m nominal)	2006/07	2007/08	2008/09	2009/10	2010/11
UAG Approved Value ($m)[66]	1.5	1.4	1.4	1.3	1.2
UAG Unit Cost ($/GJ)	5.00	5.19	5.37	5.56	5.75
UAG Forecast Volume (TJ)	300	270	261	234	226
Forecast Gas Injections (TJ)	10,338	10,534	10,774	10,962	11,190
UAG Volume (%)	**2.9**	**2.6**	**2.4**	**2.1**	**2.0**

The level of UAG, expressed as a percentage of gas injections is shown graphically below.

[66] Queensland Competition Authority, *Final Approval – Revised Access Arrangement for Gas Distribution Networks: Allgas Energy*, June 2006, Table 13.5

Figure 8-2 APT Allgas Historical & Forecast UAG for Previous Access Determination



It can be seen from this that in determining an appropriate level of UAG on the APT Allgas distribution network, it was assumed that the historical downward trend would be continued for almost the full term of the ensuing access arrangement.

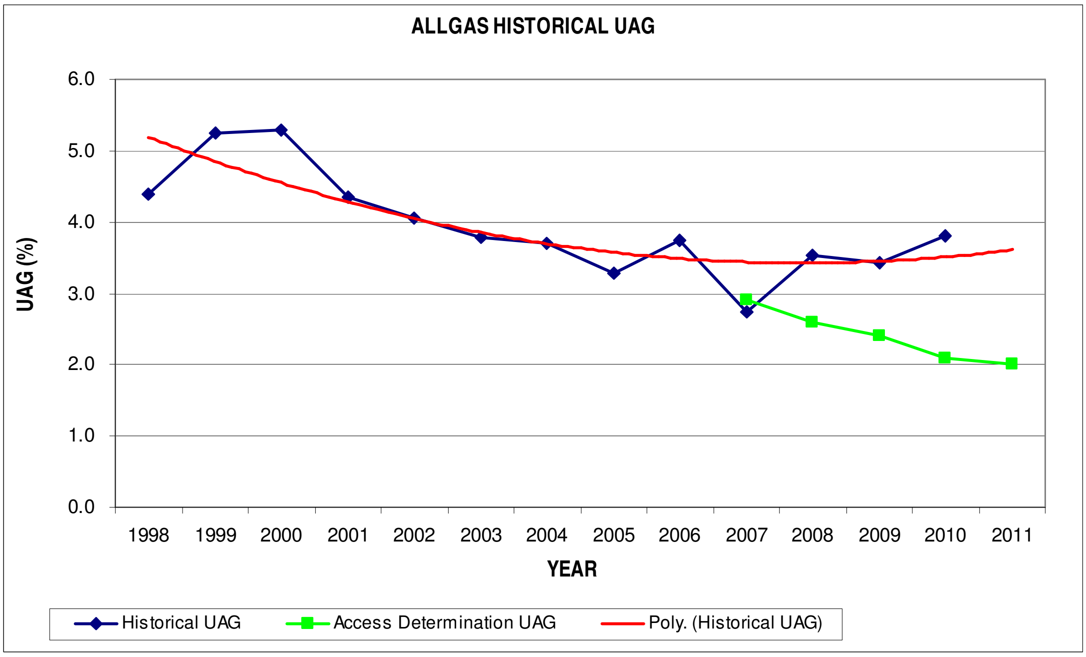
Table 8-5. below, shows the actual level of UAG on the APT Allgas network for the 2006-11 AA period, expressed as a percentage of gas injections.

Table 8-5 Historical UAG on the APT Allgas Network

(%)	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
UAG (%)	4.4	5.2	5.3	4.3	4.1	3.8	3.7	3.3	3.7	2.7	3.5	3.4	3.8

This data is shown graphically below.

Figure 8-3 APT Allgas Historical UAG



It can be seen from this that although APT Allgas has continued the overall downward trend of UAG on its networks, the rate of descent forecast in the 2006 Access Determination has not been sustained.

APT Allgas calculates that the overall level of UAG on its networks for the 2010 financial year is 3.8%.

This variation between forecast and actual UAG may primarily be attributed to two factors. They are:

- The linear extrapolation of the rate of reduction of UAG has proved to be an unreliable indicator of trend in the level of UAG over the 2006-11 AA period, as it over-emphasised the contribution of mains replacement to reductions in the overall level of UAG;
- As part of the move to Full Retail Contestability, APT Allgas installed new metering and telemetry equipment for major consumers. Problems were experienced with the telemetry equipment which were not immediately detected. These problems adversely affected UAG.

APT Allgas now asserts that the level of UAG in the 2006-11 Access Arrangement Submission was lower than could reasonably be achieved in the given conditions.

Despite this, APT Allgas maintains that UAG on it's networks has remained within an efficient range, and, as demonstrated in the Table 8-6 below, is comparable with other utilities with similar network characteristics.

Table 8-6 Benchmark APT Allgas UAG

	APT Allgas (Qld)	Envestra (Qld)[67]	Actew (ACT)[68]	Jemena (NSW)[69,70]	Multinet (Vic)[71]
UAG (GJ/km Mains)	142	46	33	96	191
CI & Other non-Plastic Mains (%)	18	17	0	2	16

It should be noted that the unit GJ/km Mains has been deliberately chosen rather than the traditional percentage of gas delivered as the unit of benchmarking. This has been done to compensate for the relatively low rate of energy delivery per km of mains for gas distribution in Queensland compared to Southern states, and the fact that leakage from the network assets is proportional to defects in the assets and the operating pressure, rather than the volume of gas passing through the asset. In choosing this measure, it is acknowledged that leakage from mains and services is not the only component of UAG, but that while a significant length of cast iron and other non-plastic mains exist on the APT Allgas distribution network, leakage from mains and services is a major contributor to UAG. The percentage of cast iron and other unprotected steel mains in each of the benchmarked networks has been provided to allow a more meaningful comparison to be made.

8.2 *Key Performance Indicators for APT Allgas Operating Costs 2007 - 2010*

The key performance indicators (KPIs) of the actual Operating Costs to date for the 2006-11 AA Period are shown in Table 8-7, below. This table also shows the benchmarked unit operating costs achieved for Total Operating Cost per Kilometre of Mains, and Total Operating Costs per Consumer during this period.

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[67] Source data from Envestra Queensland Networks Asset Management Plan, 2010

[68] Source data from ActewAGL, *Gas Network Performance Benchmark Study FY2000-FY2008*, May 2009

[69] Source data from Australian Energy Regulator, *Final Decision Public – Jemena Gas Networks – Access Arrangement Proposal for the NSW Gas Networks, 1 July 2010 – 30 June 2015*, June 2010, Table 9.2

[70] Source data from Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information*, 25 August 2009, Section 2.1.2

[71] Source data from ActewAGL, *Gas Network Performance Benchmark Study FY2000-FY2008*, May 2009

Table 8-7 APT Allgas Actual Operating Cost KPIs 2007-2010

	2006/07	2007/08	2008/09	2009/10
Total Operating Costs ($m 10/11)	15.83	15.73	16.04	17.43
Total Operating Costs ($m10/11) per km Mains	5,735	5,551	5,533	5,945
Total Operating Costs ($m10/11) per Consumer	217	206	201	213

From this it can be seen that despite an increase in total operating costs per kilometre of mains, total operating costs per consumer have declined over the 2006-11AA period.

8.3 *Forecast operating expenditure*

8.3.1 Forecast methodology and assumptions

This Section of this Access Arrangement Submission addresses the requirement of Rule 72(1)(e) for the access arrangement information to include a "forecast of operating expenditure over the access arrangement period and justification for the forecast".

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 delivering pipeline services".

Greenhouse gas emissions trading costs and taxes have not been included in non-capital costs, as it is intended that these should be separately assessed and included as pass-through costs should they become applicable at some future point during the tenure of this Access Arrangement.

For the purpose of forecasting operating expenditure, APT Allgas has used the base year methodology. This methodology involves the following steps:

- Selection of an appropriate base year in which to measure costs (Section 8.3.2);
- Modification of the base year costs to ensure that all costs required for future operation of the network are added to the base year costs, and all costs in the

base year costs which are not relevant to future operation of the network are subtracted from the base year costs (Section 8.3.4);

- Modification of base year costs as required to reflect changed consumer numbers, and additional network facilities required to supply gas to these additional consumers, and increased loads from existing consumers (Section 8.3.4.3);
- Modification of the base year costs to reflect changes in input costs anticipated over the access arrangement period (Section 8.3.4.2); and
- Modification of the base year costs to reflect appropriate productivity improvements (Section 8.3.4.3).

Applied Escalation Rates

For the purpose of calculating the forecast operating costs over the 2011-16 AA period, actual costs for the base year were escalated annually. Costs resulting from adoption of the recommendations in the above business cases were added in the appropriate year, and escalated annually thereafter.

Table 8-8. details the escalation factors used by APT Allgas in preparation of this Access Arrangement Submission.

Table 8-8: Applied Escalation Factors

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
All Components except those specifically mentioned below[72]	1.5	0.1	0.9	1.3	1.5	1.6
Regulatory[73]	20.0	10.0	10.0	1.3	1.5	1.6
Purchased Gas[74]	1.5	5.1	8.4	13.7	1.8	0.8

Scope and Step Changes have been used to describe significant changes to forecast Operating Costs over the 2011-16 AA period. Additional operating costs resulting from network organic factors such as growth in consumer numbers and mains lengths have also been applied to the base year operating costs.

[72] Access Economics, *Forecast Growth in Labour Costs*, March 2010

[73] Verbal advice from Queensland Department of Mines & Energy

[74] Based on information contained within McLennan Magasinik Associates, *Annual Gas Market Review Report to DEEDI*, 23 June 2010

Productivity on operating and maintenance costs

Improvements in productivity and maintenance costs have been included in the forecast costs for the 2011-16 AA period as embedded efficiency improvements.

As can be seen in Table 8-18,Table 8-19,Figure 8-14 and Figure 8-15, Total Operations Costs per Kilometre of Mains are forecast to increase by 1.1% over the course of the 2011-16 AA period. Much of this increase is due to the proposed scope and step changes. When these are excluded from the calculation, Total Operating Costs per Kilometre of Mains increase by just 0.4%.

At the same time, Total Operations Costs per Consumer are forecast to decrease over the 2011-16 AA period by 4.9% from $223 to $212. When the cost of the proposed Scope and Step Changes is excluded, the decrease in unit costs over the same period becomes larger, increasing to 5.4%, from $202 to $191.

8.3.2 Determination of the base year

Forecasts of operating costs have been developed for the 2011-16 AA period. Financial year 2010 has been used as the base year from which to forecast future costs in this Access Arrangement Submission. Financial year 2010 has been chosen as the base year because:

- Financial year 2010 is the latest financial year for which actual operating costs are available prior to the submission of this Access Arrangement;
- Financial year 2010 actual costs include realised benefits of the synergies APA has obtained through joint management of both the APT Allgas and Envestra Queensland networks. The effect of these cost savings may be seen in the reduction in unit operating costs per consumer of the APT Allgas distribution network, in Table 8-7, where unit costs per consumer have decreased over this period.

8.3.3 Benchmarking and Efficiency

In order to be able to use the base year methodology, it is first necessary to validate the efficiency of the base year costs. To achieve this validation, three key operating parameters of the APT Allgas network have been benchmarked against other gas distribution networks. Where necessary the benchmarks used were modified to compensate for significant differences in network characteristics and achieve a degree of parity between network comparisons. Explanations have been provided wherever these modifications have been necessary.

For the purposes of this benchmarking exercise, the APT Allgas network has been benchmarked against the following networks:

- Envestra Queensland;
- Jemena Gas Networks (NSW) Ltd;
- ActewAGL Distribution, ACT, Queanbeyan and Palerang gas distribution network.

The major characteristics of these networks are listed in Table 8-9.

Table 8-9 Key Characteristics of Benchmarked Networks – 2009/10

		APT Allgas Qld	Envestra[75] Qld	Jemena NSW	Actew/AGL ACT
Regulated Asset Base Value	$m	377	311	3,837[76]	303[77]
Energy Transported	PJ	11	16	101[78]	8[79]
Total Mains Length	km	2,932	2,043	24,434[80]	4,048[81]
Plastic Mains Length	km	1,938	1,541	22,119	3,771
Protected Steel Mains Length	km	470	151	1,838	277
CI, UPS & PVC Mains Length	km	524	351	477	0
Number of Consumers	K	82	84	1,053[82]	116[83]

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[75] Envestra Qld Networks Technical Asset Management Plan, Version 0.4, June 2010

[76] Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information*, 25 August 2009, Table 10.3

[77] ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Table 7.3

[78] Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information,* 25 August 2009, Table 2.1

[79] ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Table 5.1

[80] All mains data sourced from Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information,* 25 August 2009, Section 2.1.2

[81] All mains data sourced from ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Table 2.1

[82] Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information,* 25 August 2009, Table 2.1

[83] ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Table 5.4

UAG	TJ	416	94	2,354[84]	135[85]
Total Operating Costs	$m	17	19	127[86]	20[87]

The benchmarks derived from these key characteristics are:

- Total Operating Costs per kilometre of mains ($/km);
- Total Operating Costs per consumer ($/cons);
- Total Operating Costs per Regulated Asset Base value (%).

Total Operating Costs per Kilometre of Mains

Total Operating Costs per Kilometre of Mains is the most widely used and quoted measure within the gas distribution industry. There are widely differing results for this measure, many of which occur because of differences in interpretation as to which costs should be included in Total Operating Costs. Wherever possible, parity of inclusions has been maintained in this Submission. For this exercise, the following costs have been included in the Total Operating Costs:

- Operating & Maintenance;
- Marketing;
- Administration & Strategic Planning;
- Corporate Overheads;
- Customer Service;
- UAG;
- Government Charges;
- Contestability costs; and
- Other.

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[84] Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information*, 25 August 2009, Table 4.7
[85] ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Section 9.1.3.3
[86] Jemena Gas Networks (NSW) Ltd, *Access Arrangement Information,* 25 August 2009, Table 4.7
[87] ActewAGL Distribution, *Access Arrangement Information for the ACT, Queanbeyan and Palerang gas distribution network*, June 2009, Table 9.1

Self insurance and debt raising costs are not included in Total Operating Costs for the purpose of this benchmarking exercise.

Table 8-10. shows the Total Operating Costs both including and excluding UAG per km of mains.

Table 8-10 Total Operating Costs per Kilometre of Mains

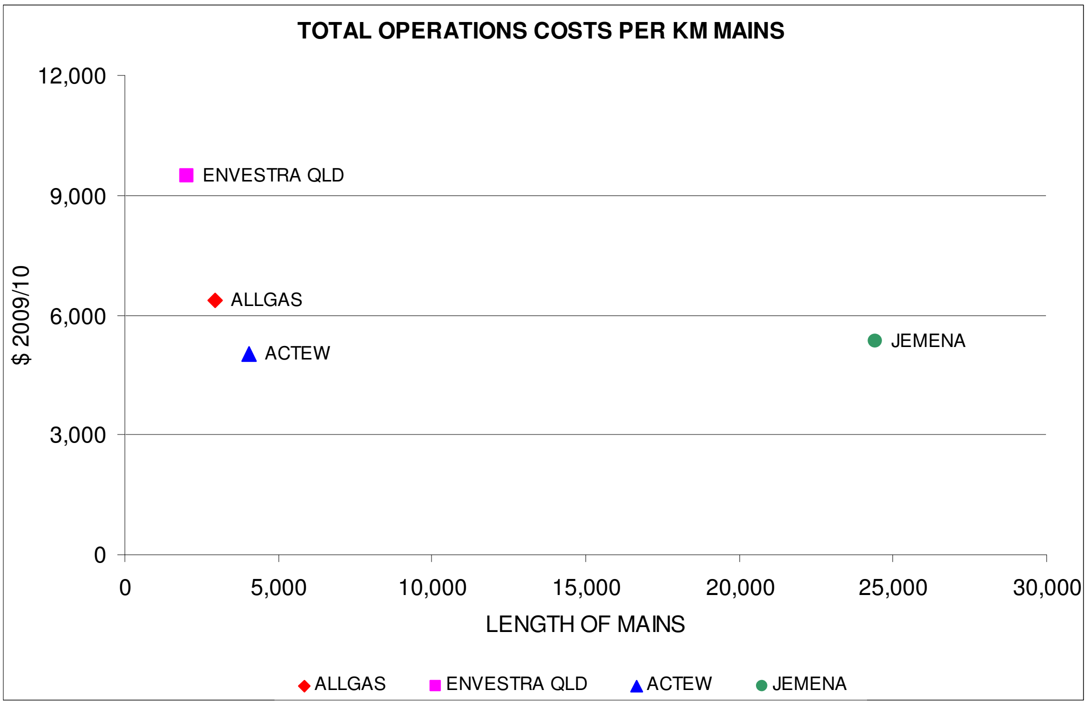
($2009/10)		APT Allgas	Envestra Qld	Jemena NSW	Actew/AGL ACT
Total Mains Length	km	2,932	2,043	24,434	4,048
Proportion of CI, UPS and PVC Mains	%	18	17	2	0
Total Operating Costs per km Mains	$/km	5,769	9,218	5,192	4,867
Total Operating Costs (excluding UAG) per km Mains	$/km	5,026	8,978	4,717	4,684

The median value for total operating costs per kilometre of mains for these network operators is $5,481, with values ranging from a low of $4,867 to a high of $9,218. At $5,769 APT Allgas' operating costs are higher than the median value, but comparable to the values for the smaller operators.

The mean value for total operating costs per kilometre of mains for these network operators is $6,261, with a standard deviation of $2,006. At $5,769, APT Allgas operating costs are less than the mean. APT Allgas' Total Operating Costs per kilometre of mains may therefore be deemed to be efficient.

These results may be seen in Figure 8-4 below.

Figure 8-4 – Total operations Costs per Kilometre of Mains



Total Operating Costs per kilometre of mains, without modification however, takes no account of variable operating characteristics between different networks. Some modification to decrease the level of variability may be useful. For example, the costs of UAG on the APT Allgas network for 09/10 comprised 13% of the total operating costs. As discussed elsewhere in this document, UAG is significantly influenced by the length of cast iron, unprotected steel and PVC mains and services on the network. 18% of APT Allgas' network is constructed from these high leakage materials, compared to 2% on the Jemena network and 0% on ActewAGL network. It has been calculated that on the APT Allgas network these old materials contribute over 45TJ p.a. to UAG. This has a value of $265K p.a. in operating costs.

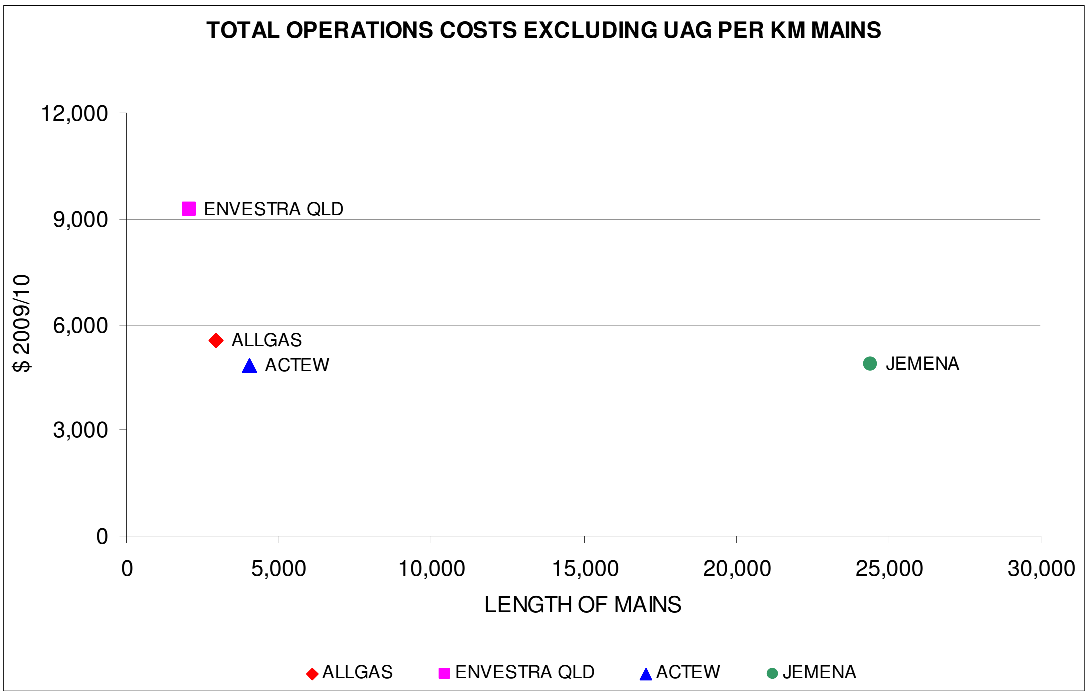
A further benchmark has therefore been provided which reduces this variability between networks by subtracting the cost of UAG apportioned to network constructions of older materials from total operating costs. This was done for each operator before calculating the revised benchmarks, and was done by applying APT Allgas' network characteristics to the age and condition of mains in each of the benchmarked networks. This was done as specific network data on each network was not available. In addition, cost of gas will also be different for each operator. None of these variables are reflected in this calculation, with the calculations for all operators based on variables typically found on the APT Allgas network.

The median value for total operating costs excluding UAG costs attributable to old mains and services per kilometre of mains for these network operators is $4,871, with values ranging from a low of $4,684 to a high of $8,978. At $5,026, APT Allgas' operating costs are slightly greater than the median value.

The mean value for total operating costs excluding UAG costs attributable to old mains and services per kilometre of mains for the benchmarked network operators is $5,851, with a standard deviation of $2,090. At $5,026 APT Allgas' modified Total Operating Costs per km of mains are less than the mean costs for all the benchmarked operators. APT Allgas' operating costs per kilometre of mains for financial year 2010 may therefore be deemed to be efficient.

These results may be seen in Figure 8-5 below.

Figure 8-5 – Total Operations Costs Excluding UAG per Kilometre of Mains



Total Operating Costs per Consumer

Total operating costs per consumer is another common benchmarking measure.

Table 8-11 below, shows the result of this benchmarking measure.

Table 8-11 Total Operating Costs per Consumer

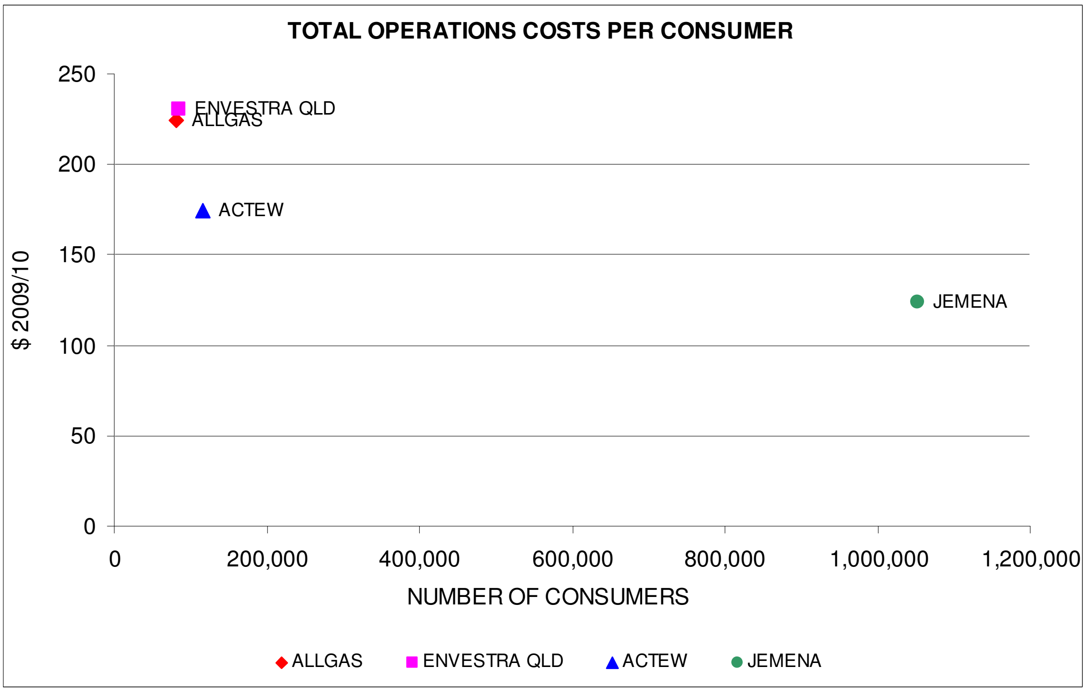
($2009/10)		APT Allgas Qld	Envestra Qld	Jemena NSW	Actew/AGL ACT
Total Consumers (Thousands)	No.	82	84	1,053	116
Total Operating Costs per Consumer	$/cons	207	224	120	170
Total Operating Costs excluding UAG per Consumer	$/cons	195	218	109	163

The median value for total operating costs per consumer for these network operators is $188, with values ranging from a low of $120 to a high of $224. At $206 APT Allgas' operating costs per consumer are slightly above the median value of all the benchmarked operators.

The mean value for total operating costs per kilometre of mains for these network operators is $180, with a standard deviation of $46. At $206, APT Allgas operating costs are greater than the mean, but less than the 1st standard deviation above the mean.

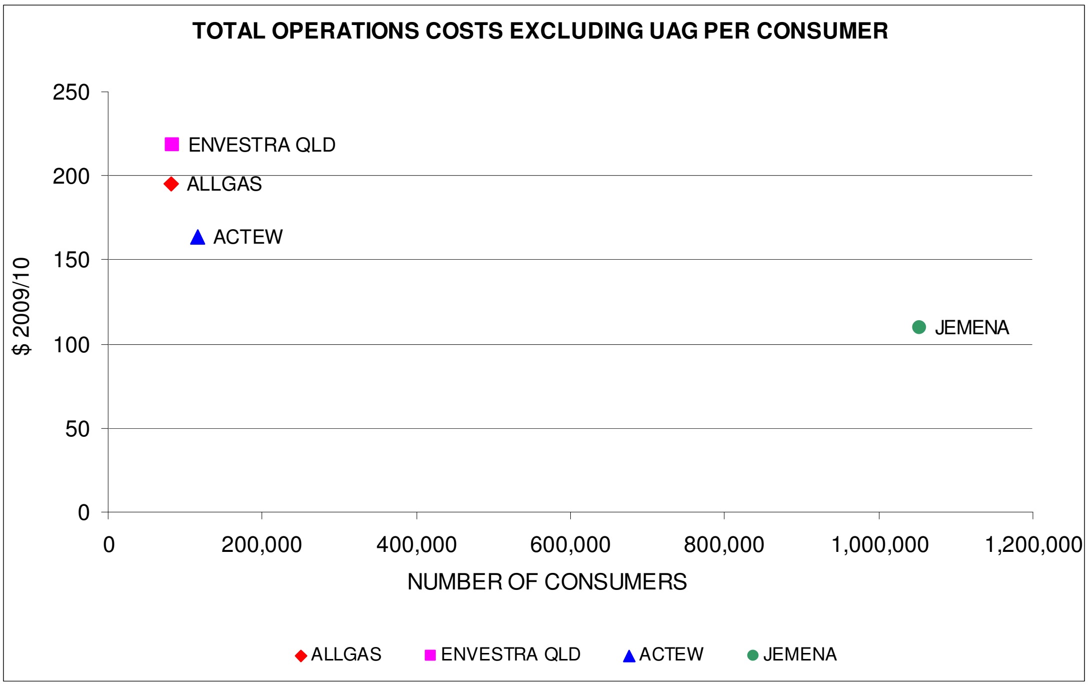
These results are shown in Figure 8-6 below.

Figure 8-6– Total Operations Costs per Consumer



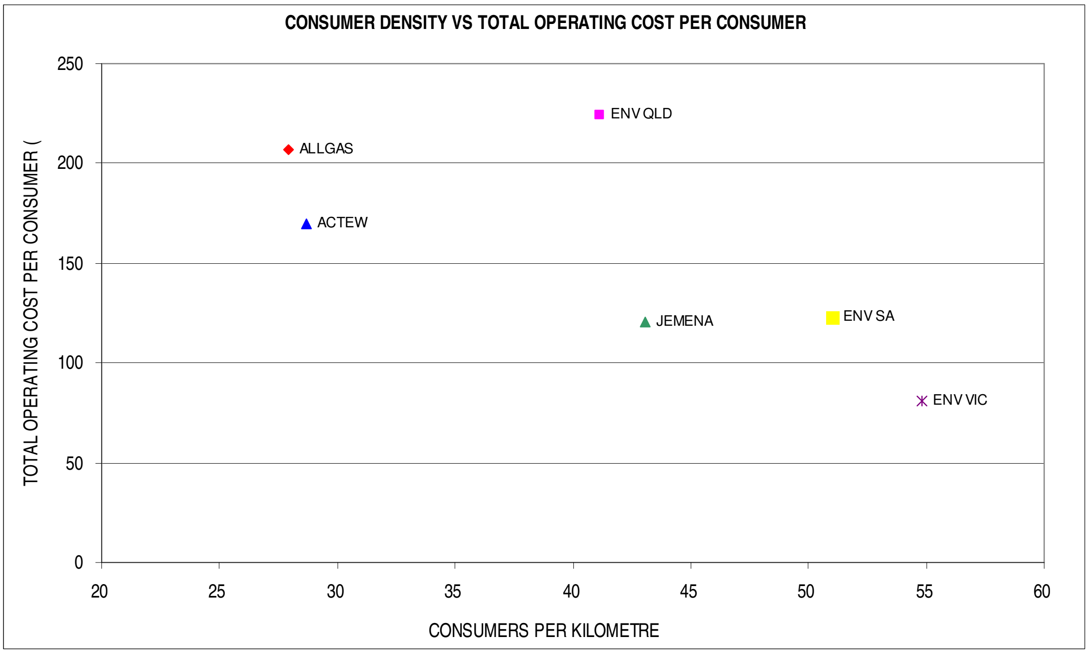
As can be seen by Figure 8-7 below, this measure is also influenced by UAG on the network.

Figure 8-7 – Total Operating Costs Excluding UAG per Consumer



However, total operating costs per consumer is also dependant on consumer density. Figure 8-8 demonstrates the relationship between consumer density and total operating cost per consumer for the benchmarked networks.

Figure 8-8 – Consumer Density vs Total Operating Cost per Consumer[88]



From this it can be seen that the average density of consumers on the APT Allgas network is the lowest of any of the benchmarked networks. It can also be seen that a relationship appears to exist between consumer density per kilometre of mains and costs per consumer, and that APT Allgas' Total Operating Costs per Consumer are comparable to other distribution networks with similar consumer densities.

APT Allgas' Total Operating Costs per Consumer for financial year 2010 may therefore be deemed to be efficient.

Total Operating Costs as a Percentage of Regulated Asset Base (RAB) Value

Total operating costs as a percentage of RAB value is a commonly used benchmarking measure used within gas distribution utilities. However, comparison between utilities using this measure is largely meaningless as the output is as much dependant on the network characteristics as it is on the efficiency with which the network is operated. For example, a distribution network comprising a high proportion of old mains, will have a very low RAB, but high operating costs, due to the large number of leaks on the network.

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[88] The data for Envestra SA and Envestra Vic networks used in preparing this figure is 2008 data taken from ActewAGL, *Gas Network Performance Benchmark Study FY2000 – FY2008*. All other data is 2010 data.

This means Total Operating Costs as a percentage of RAB value will be increased at a rate disproportionate to any one factor. Similarly, a new network, will have a higher RAB, but the cost of leak repair will be substantially reduced from that of the old network operator, thereby disproportionately reducing this benchmarking measure. Despite this inherent failure in this measure, the results may be seen in Table 8-12 below.

Table 8-12 Total Operating Costs as a Percentage of RAB Value

($09-10)		APT Allgas Qld	Envestra Qld	Jemena NSW	Actew/AGL ACT
Total Operating Costs as a percentage of RAB Value	%	4.5	6.1	3.3	6.5

The median value for Total Operating Costs as a percentage of RAB value for the benchmarked network operators is 5.3%, with values ranging from a low of 3.3% to a high of 6.5%. At 4.5% APT Allgas' operating costs are less than the median of the network operators' collective values.

The mean value for total operating costs per as a percentage of RAB value for these network operators is 5.1%, with a standard deviation of 1.5%. At 4.5%, APT Allgas Total Operating Costs as a percentage of RAB value are less than the mean. APT Allgas' operating costs may therefore be deemed to be efficient.

8.3.4 Adjustments to base year costs

8.3.4.1 General Adjustments to Base Year Costs

APT Allgas has included further operating efficiency savings over those achieved in the 2006-11 AA period where these are expected to be realised during the 2011-16 AA period. APT Allgas has also included appropriate additional operating costs over those incurred in financial year 2010 where these are expected to be incurred during the 2011-16 AA period, and which are considered by APT Allgas to be both prudent and efficient. Cost savings or additional costs have been applied in the financial year in which the savings or additional costs are expected to occur. Where these changes in costs are significant, they have been described in Section 8.3.4.2 – Step and Scope Changes. Less significant cost changes, used in development of the forecast costs are summarised below. A description of activity specific cost variations may be found Section 8.3.4.3

Less significant cost variations from base year costs included in the forecast Access Arrangement costs are:

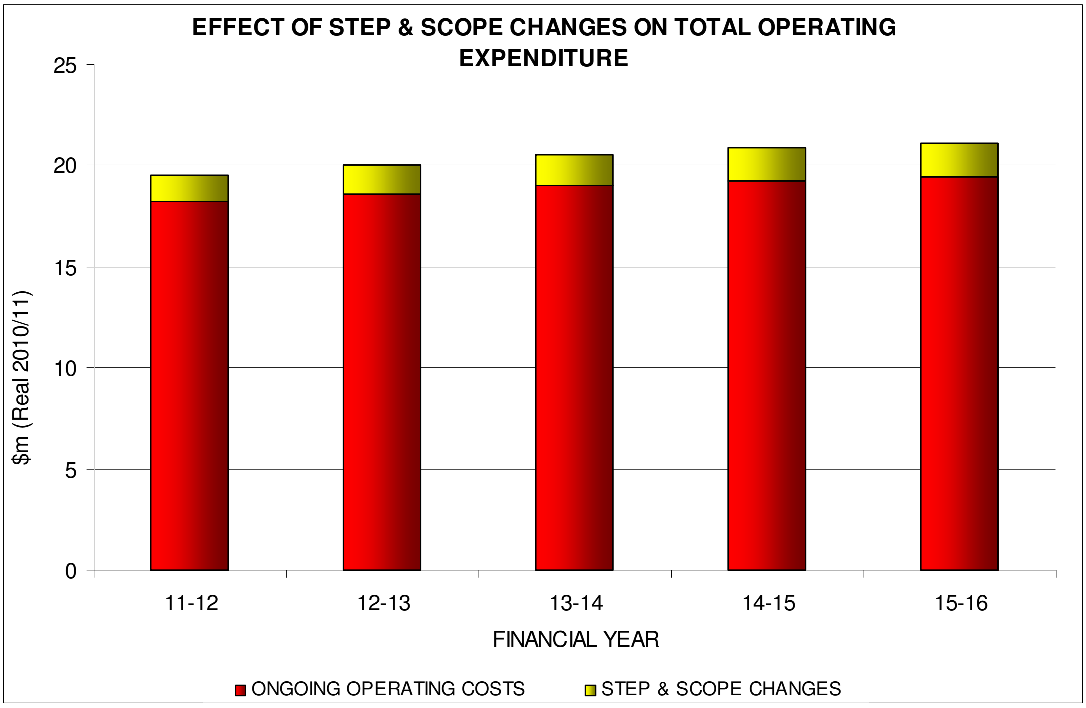
- All miscellaneous, non-repetitive income in the base year have been assumed not to continue during the 2011-2016 AA period;
- Metering costs have been increased to reflect more frequent meter checks for demand consumers during the 2011-2016 AA period to expedite prompt recognition of significant consumption changes;
- Metering and consumer service costs have been increased in proportion to consumer growth;
- Administration costs have been reduced in line with planned decrease in resources;
- Metering and billing costs have been reduced to reflect a change to common systems throughout APA;
- Leak repair costs on mains and services have been reduced in line with changes resulting from the mains replacement program;
- Leak repair of meters has been increased in proportion to consumer growth;
- Leakage survey costs have been increased in proportion to mains length;
- UAG volume has been reduced to reflect the effect of the mains replacement program.

8.3.4.2 Step and Scope Changes

Where additional costs are considered to be significant, scope or step changes have been included in this Access Arrangement Submission. These scope and strep changes are summarised below. Copies of all these scope and step changes may be found as Attachment 4.8, Capex and Opex Business Cases, to this Submission.

The relative total effect of these step and scope changes on APT Allgas' forecast operating costs may be seen below.

Figure 8-9 Effect of Step and Scope Changes on Total Operating Expenditure



Appointment of a Revenue Protection Officer

The cost of UAG on the APT Allgas distribution network is currently just over $2m per annum, and is expected to rise to $2.4m per annum in financial year 2011-12. This is a significant cost to APT Allgas. As discussed elsewhere in this Submission, UAG on this Network has been at higher levels than allowed by the QCA in APT Allgas' previous Access Arrangement. The historical UAG on the APT Allgas network is shown in Table 8-13 below.

Table 8-13 APT Allgas UAG Historical Trend 2006 - 2010

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual
Volume (TJs)	254	445	438	416
Volume (%)	2.4	4.0	4.0	3.8
Cost ($m (nominal))	1.9	2.0	2.3	2.2
AA Determination	1.5	1.4	1.4	1.3

UAG is considered to be a normal parameter of a gas distribution network operation. Leakage from the network is typically a major component of UAG. In addition to leakage, metering errors are a significant contributor to UAG.

UAG has been trending downwards recently due to a project to achieve this outcome using seconded resources. This step change identified that for this downwards trend to continue, or even for the current level of UAG to be maintained, a full time dedicated resource is required to continually monitor and investigate metering anomalies. This step change therefore argues for additional resources to be employed for this purpose.

Replacement of Lids on Cocon District Regulator Stations

This project presents a strategy for planned replacement of lightweight lids on Cocon District Regulator Stations. The original lids installed on these stations have been found to be inadequate to cope with loadings being typically experienced. Plastic deformation of the lids has been occuring. This has resulted in ingress of water and contaminants into the regulator stations, particularly in adverse weather conditions. In addition the buckled lids are a potential trip hazard to the general public. It is proposed to replace these light duty lids with redesigned, lids able to withstand typical loadings. There are currently 30 installations of this type requiring lid replacement.

This step change details the resources required to replace the problem lids with a lid not prone to buckling under load.

Instigation of a Bridge Crossing Maintenance Program

Steel pipelines operating at high pressure provide the backbone of the APT Allgas distribution system. Where required, these pipelines cross rivers, creeks, railway lines etc. While the majority of these crossings are underbored, a number have been constructed using an existing bridge or dedicated gantry as the supporting structure for the pipeline. As contact with the ground is non-existent in these situations, these bridge crossings rely solely on the pipeline coating to maintain pipeline structural integrity. It is therefore important to ensure the integrity of the pipeline coating is maintained.

Bridge crossings are inspected by pipeline patrols at least monthly, and for classified pipelines weekly. However, these inspections are limited to fairly cursory visual inspections, with no disruption to the pipeline coating in performing this work. Ideally, the condition of these pipelines should be periodically assessed by removal of the coating, with any required maintenance performed at the time. There has only been 1 instance in the past 5 years of work of this nature having been carried out.

It is planned to introduce a program of regular inspection, and maintenance as required, of the above ground steel pipeline bridge crossings. This program is proposed to ensure maintenance of the pipelines' integrity and suitability for continued operation, and to comply with the additional pipeline integrity assessments required under AS 2885.

This step change seeks to provide funds to permit a program of regular inspection and maintenance, in which a predefined number of bridge crossings are thoroughly inspected, and maintained as required, each year.

Condition Monitoring of Cased Pipelines

In 2007, APT Allgas carried out an investigation of steel pipelines and mains in casings. The report from this investigation documented the extent of the problem, and recommended regular inspections of all affected sites. Although partial implementation of these recommendations occurred, they have not been fully implemented due to resourcing constraints.

APT Allgas currently has 297 known instances of this type of installation on its network.

Recent APT Allgas experience has demonstrated the importance of implementation of the report's recommendations to maintain the integrity of steel pipelines and gas mains in casings.

The problem with steel pipelines in casings occurs because of a combination of previous installation practices which damaged pipeline coating systems during installation, and a lack of cathodic protection within the casing.

This proposal seeks to increase the monitoring program for cased steel pipelines, in accordance with the Report's recommendations, to ensure the ongoing integrity of the affected pipeline. The knowledge gained from this monitoring program will enable APT Allgas to take timely and appropriate action to prevent uncontrolled and potentially catastrophic failure of the affected sites on the APT Allgas network.

Implementation of Market Rule Changes

Participation in the various rules committees is now a necessary part of gas distribution business. The national framework for gas market arrangements governs the wholesale and retail gas market in Queensland. The Australian Energy Market Operator (AEMO) is the gas market operator for QLD, where full retail contestability commenced in July 2007.

It is necessary to resource adequate representation on market rules committees in order to ensure that APA's interests are protected. This is an activity that was not incorporated in the previous Access Arrangement. It is now recognised that we are under-resourced to adequately cope with this activity.

In addition, the implementation of the Short Term Trading Market (STTM) in QLD will commence when implementation of the pilot markets in South Australia and New South Wales is complete. This will increase commercial risk for market participants trading in the market. With this, there will be a greater emphasis on the quality and reliability of metering data delivered to the market on a daily basis by service providers (including APT Allgas).

This will require additional resourcing to allow the implementation of 7 day/week remote monitoring of gas day data, in order to manage this increased risk.

This scope change details resource requirements to meet these obligations.

Electricity to Gas Hot Water Changeover Program

Average residential consumption in Queensland is significantly below that of other states. This is due to a variety of factors, the most significant being Queensland's sub-tropical climate and the associated low demand for space heating.

Average residential consumption has been falling for several years now, largely due to the decline in (hot) water consumption, and the move to reverse cycle air conditioners for space heating and cooling. The effect of this is that network utilisation has declined in recent years, and is likely to stay low in the foreseeable future.

It is planned to mitigate this trend of falling average residential gas consumption and grow the demand for gas through additional marketing, such as the proposed implementation of an Existing Home Electricity to Gas Hot Water Changeover Program.

The forecast cost of this activity over the next AA period is $1.95 m.

Increased demand for gas will allow the fixed costs of operating the network to be spread across a higher gas throughput and a greater number of connections, resulting in lower customer tariffs.

Development & Deployment of New Technology

Average residential consumption in Queensland is significantly below that of other states. This is due to a variety of factors, the most significant being Queensland's sub-tropical climate and the associated low demand for space heating. In addition, average residential consumption has been dropping for several years now, largely due to the decline in (hot) water consumption, and the move to reverse cycle air conditioners for space heating and cooling. The effect of this is that network utilisation has declined in recent years, and is likely to stay low in the foreseeable future.

In order to mitigate this situation, it is planned to establish a New Technology role to facilitate the deployment of evolving gas technologies into the Queensland market.

Extension of Leakage Survey Program

The gas industry throughout Australia regularly performs leakage survey on its assets to ensure that gas leaks are detected, assessed, and appropriate action taken. This is done to both mitigate the risks associated with leaking gas, and to manage the volume of gas lost to leakage.

APT Allgas has traditionally performed regular programmed leakage survey on all pipelines and mains on a five year basis, and designated high risk areas on an annual basis. Consumer services are not currently leakage surveyed, despite these being considered part of APT Allgas' network under the Qld Petroleum and Gas Regulations.

A recent trial carried out by APT Allgas, found higher than expected numbers of leaks both on services and meter sets. As a result of this, it is now proposed to extend the current leakage survey program to include the leakage survey of services and meter sets on designated areas which have been deemed to be of higher risk. It is proposed to extend the current leakage survey program to include services and meter sets in existing low and medium pressure districts, as the mains and services in these districts are constructed from cast iron, unprotected steel, and PVC and are now in excess of 20 years old.

Unaccounted for Gas

This business case explains the forecast costs of UAG on the APT Allgas network.

UAG is generally defined as the volume of gas injected into a gas distribution network, less the volume of gas billed to consumers.

UAG may be attributed to a variety of factors, the relative importance of which is specific to individual network attributes. Some of the more common and significant factors contributing to UAG are leakage, metering errors, misappropriation of gas, system processing errors, telemetry errors, and gas lost from damages.

This business case discusses the relative contribution of these factors to UAG on the APT Allgas network, and explains the forecast step change in the cost of UAG to APT Allgas from around $2m per annum to $2.9m per annum in financial year 2014.

Roadmap Initiative

APA has been following an IT architectural blueprint and roadmap initiative (RMI) developed in 2006 that supports the business strategic direction while addressing existing architectural weaknesses and functionality that restrain business performance.

The roadmap initiative proposes to introduce four projects:

- National Works Management;
- Field Data Capture;
- Billing Optimisation;
- Advanced Asset Management.

In February 2009 an independent external review of the RMI was conducted by representatives from Logica. The review established that APA's business challenge to reduce costs - some of which are regulatory driven - are being addressed with the following business strategies:

- National systems and processes (national strategy, local delivery);
- Maintain core capability in-house;
- Save costs through improved work practices;
- Delivery of prudent and efficient services to APA Group.

That review confirmed that the RMI objectives remain aligned with both APA Group business objectives and international best practices and thus the RMI is still sound in the following ways:

- Recognition of agreed business strategic focus and priorities;
- Use of an holistic approach to guiding architectural principles (infrastructure, application, processes/people, data/information);
- Consider alignment with the business strategy and the need for a national approach to common processes;
- Addressing the historical silos of information through the use of collaborative technologies such as an enterprise services bus;
- Reduction in IT costs through rationalisation of applications and systems.

The RMI is designed to take advantage of hardware end of life and software upgrade opportunities to deliver enhanced functionality and reduce total costs of IT ownership.

Knowledge Management

This project is required to develop and support a knowledge management solution for APT Allgas.

In the past APT Allgas have relied on long term employment of personnel and "on the job" training to support knowledge management and knowledge transfer within the organisation. While this may have been suitable in the past it is not appropriate in the current employment environment which is seeing a move towards shorter length of employment (typically of 5 to 10 years) rather than longer (eg.15 years and more). Coupled with the changing employment environment and an ageing workforce is also the changing business environment which is seeing more and more regulation and auditing by external bodies which is placing a stronger need to have well documented processes and information that can be audited and systems to manage the documentation.

8.3.4.3 *Project specific costs*

Customer Growth

As described elsewhere in this Submission, APT Allgas expects to connect between 2,500 and 3,200 additional consumers of natural gas each year over the 2011-16 AA period. From a base number of consumers of nearly 82,000 in financial year 2010, the number of consumers is predicted to increase to almost 100,000 in financial year 2016. The operating costs associated with servicing the additional consumers' therefore need to be adjusted appropriately to reflect this increase in numbers.

The ratio between total operating costs and the number of consumers on the network is not necessarily linear and in a ratio of 1:1. This is because, for some activities undertaken under the gamut of network operations and maintenance, the unit operating costs remain relatively stable over a large range in the numbers of consumer serviced. This contrasts with other activities for which the relationship between costs and numbers of consumers is directly proportional or even unitary.

For this Access Arrangement the forecast costs which have been increased at a unitary proportional relationship to predicted consumer numbers are customer service, meter reading, provision of a call centre for consumer complaints, repair of leaks at meters, and costs associated with meter maintenance.

Activities where the relationship is not proportional, are covered under the Sub-section Network Growth, below.

Network Growth

Network growth is defined as the increase in physical network assets. Network growth data used in this Section is based on data supplied in the capex sections of this Submission. It should be noted here that network growth is inclusive of all the network assets including mains, pipelines, gate stations, district regulator stations and other associated facilities.

The cost of a number of operating activities, although linked to changes in consumer numbers, vary at a different rate to variation in the number of consumers. A number of these activities increase in proportion with increased network size. For this Submission the forecast costs which have been increased proportionally to predicted network size are electronics & instrumentation, pressure control, pipeline maintenance (in proportion to steel pipeline length), leakage survey and patrol, site watches & locations, and repairs to damaged APT Allgas assets.

Leak Repair

All new pipelines are constructed from protected steel, and all new mains are plastic, generally medium density polyethylene (MDPE). The rate of leaks on MDPE mains is 0.03 leaks per km per year compared to the 1.1 leaks per km per year for mains constructed from materials such as unprotected steel, cast iron and PVC. This means that the increase in the numbers of leaks resulting from network growth is very small.

The repair of leaks on the APT Allgas network is a major component of Network Operating and Maintenance costs, totalling over $2.9m in financial year 2010. Leak repair may be broken into leaks at meters (which includes leaks on all the components of a meter set), leaks on mains, and leaks on services.

APT Allgas currently relies on the general public to report leaks at meters. There are two factors strongly influencing the numbers of public reported leaks at meters. These are the age and condition of the meter, and level of odourisation of the network. APT Allgas has progressively implemented a program of changing odourisers, from the evaporative type to direct injection type. This has resulted in the level of odourisation of the gas now being more consistent and predictable than was the case previously. When this program is completed, variations in level of odourisation of the gas can be largely ignored as a potential variable in public reported leaks at meters. This means that numbers of public reported leaks at meters will be attributable almost solely to age and condition of the meter set and its component parts. Due to the ongoing meter replacement program, which APT Allgas carries out in accordance with AS/NZS 4944, the average age and condition of meters remains fairly constant. Therefore the rate of detection of leaks at meters should be directly proportional to the number of meter sets in service, which is in turn directly proportional to number of consumers.

AS 4645 requires that leakage survey is carried out on all of a distribution company's network assets. The Queensland Department of Mines and Energy defines the cutoff point between APT Allgas network assets and the consumers' assets as being the outlet of the meter[89]. This means that all mains and services up to and including the meter are required to be regularly leakage surveyed. While this requirement always existed, it was generally interpreted in the industry as leakage survey being required up to the property boundary. This informal interpretation was used due to the difficulty of obtaining physical access to many properties.

New and improved technology now makes it possible to leakage survey services and meter sets on most (residential) properties without the need to physically access the properties. This means that it is now generally possible to leakage survey services up to and including the meter without physically accessing the property.

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[89] Queensland Department of Mines & Energy, *Production and Gas (Production and Safety) Regulations,* 2004, Chapter 5, Part 1, Division 1.

This additional leakage survey is not yet implemented, but is planned to be implemented during the 2011-16 AA period. It is anticipated that this expansion of activities to meet the requirements of the Australian Standard will result in more leaks to be repaired. Further details of this step change may be found in the Scope and Step Change Section of this Submission.

Table 8-14. shows the historical and forecast leaks at meters. It should be noted in viewing this table that additional leaks resulting from this leakage survey activities has been added to the calculated average unit number of leaks at meter sets over 2008, 2009 and 2010.

Table 8-14: Historical and Forecast Leaks at Meters

Financial Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Leaks at Meters	1,082	861	570	734	747	764	781	798	814

It should be noted that there were no leaks at meters resulting from leakage survey activities included in the financial year 2010 leak repair data, other than the leaks resulting from the sample program.

A decline in numbers of leaks on mains has been factored in to this Access Arrangement Submission. This decline is based on the assumption that the mains replacement program described elsewhere in this Submission proceeds as planned.

The number of leaks on mains and services is dependant on the length of each type of material from which the main or service is constructed. Analysis indicates that on the APT Allgas network rate of leaks varies between 0.03 leaks per km of mains per year for MDPE mains, up to 1.1 leaks per km per year for cast iron and unprotected steel mains.

APT Allgas currently has 524 km of cast iron, unprotected steel, and PVC mains in service. Implementation of the proposed mains replacement program will reduce the length of these mains from 524 km to 416 km by the end of financial year 2016. As a result of removing these old mains from service and replacing them with MDPE mains, the annual number of leaks attributable to these old mains is expected to reduce from 815 in financial year 12 to 699 in financial year 2016. This number includes the small number of leaks on the MDPE mains replacing the old CI and unprotected steel mains.

Similarly, the lengths of services constructed from these older materials will also decline proportionally to the decline in length of the mains using these constructions as the services along this 524 km of mains are also constructed from like materials and will be replaced when the mains are replaced. Therefore, leaks on services will be beneficially affected by the mains replacement program, as services are renewed in this process. Leaks on services have therefore been reduced proportionally in line with the change in numbers of leaks on mains.

Leaks on affected services is expected to reduce from 185 in financial year 2012 to 159 in financial year 2016 as a direct consequence of the proposed mains replacement program.

Similarly the numbers of leaks on PE services will increase as new services are laid to cater for new consumers and as part of the mains replacement program. The numbers of additional leaks on services will be close to negligible.

A major problem still exists on the APT Allgas distribution network in the form of Philmac fittings. These are compression type fittings which were used extensively on the MDPE network before recurring problems with them were identified. Philmac fittings were mostly used to join risers onto PE services, but were also used to join PE mains. There are no records of how many Philmac fittings are currently in service or their location.

Philmac fittings are poor at handling differential ground movements, generally cracking and failing whenever any ground movement occurs. This results in leaks at the fittings.

APT Allgas is confident that with the ongoing regular leakage survey program on mains, many of Philmac fittings used on joining these mains have now been located and removed as they failed. However, to date, failing Philmac fittings at the bottom of service risers have not being detected except by the general public. This means that the majority of Philmac fittings used in this location will still be in service. The expansion of the leakage survey program will increase the probability of finding failed Philmac fittings. Given the lack of records as to the numbers of Philmac fittings in service, or their locations, it has been necessary to estimate this data. It is estimated that by the commencement of this Access Arrangement there will be approximately 8,000 Philmac fittings remaining in service on the APT Allgas network, and that 7% of them are leaking at any one time. Based on this assumption, the numbers of leaks due to Philmac fittings detected each year, largely as a result of the expanded leakage survey program, will be 651 in financial year 2012, decreasing annually to 487 in financial year 2016.

Table 8-15 shows the historical and forecast leaks mains and services. It should be noted that the figure for leaks on services includes the anticipated leaks on services from Philmac fittings, which will now be identified as part of the expanded leakage survey program that now includes high risk services.

Table 8-15 Historical and Forecast Leaks on Mains & Services

Financial Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Leaks on Mains				1,044	1,052	1031	1010	990	970
Leaks on Services				892	836	784	735	690	646
Total Leaks on Mains & Services	**1,969**	**2,253**	**2,322**	**1,937**	**1,888**	**1,815**	**1,745**	**1,680**	**1,616**

8.3.5 Forecast Operating Expenditure

The forecast operating expenditure for APT Allgas' gas distribution network may be found in Table 8-17.

8.3.5.1 Operating and maintenance

Operating and Maintenance costs are those day to day operating and support costs directly incurred in maintenance and operation of the network. Activities included in operating and maintenance costs may be seen in Figure 8-1.

8.3.5.2 Corporate overheads

Corporate overheads have been escalated at the rate shown in Table 8-8. The assumption has been made that the capitalisation policy currently utilised by APT Allgas for corporate costs will be maintained for the 2011-16 AA period.

8.3.5.3 Marketing

In addition to the escalation rates described in Section 8.3.1, annual marketing costs commencing financial year 2012, have been increased to accommodate the two step and scope changes described in Section 8.3.4.2, namely an Electricity to Gas Hot Water Changeover Program, and a program to increase uptake of new technologies using gas as the primary energy source. Further information on marketing activities planned for this 2011-16 AA period may be found in the APT Allgas Network Development Plan.

8.3.5.4 *Administration and Strategic Planning*

Administration and strategic planning have been escalated at the relevant rates shown in Table 8-8.

8.3.5.5 *Other allowable costs*

Government Charges

Government charges are set by the relevant government authorities.

On verbal advice from the Queensland Department of Mines and Energy, government charges have been escalated in accordance with Table 8-8.

Self Insurance

Self insurance and debt raising costs are not included in the forecasts Operating Costs.

Unaccounted for gas

Analysis has shown that leakage and therefore UAG from old cast iron and unprotected steel mains is significantly higher than leakage from new, plastic networks. The proposed mains replacement program will result in a decrease in the length of cast iron and unprotected steel mains on the APT Allgas network. This will result in reduced leakage from the network.

However, leakage from mains and services is only one cause of UAG. UAG may also occur as a result of metering errors, misappropriation of gas, system processing errors, telemetry errors, damages, etc. This means that any reduction in leakage from mains and services is unlikely to be directly proportional to reductions in UAG.

APT Allgas calculates that at its current level of UAG of 416TJ p.a., 175TJ p.a. may be attributed to leakage from cast iron and unprotected steel mains, services, philmac fittings, and PVC mains on its network. Of this, just over 70TJ is due to cast iron and unprotected steel mains and services. It is this latter figure which will be reduced directly as a result of the mains replacement program.

UAG has therefore been adjusted annually during this Access Arrangement period, in accordance with the predicted decrease in the length of cast iron and unprotected steel mains and services resulting from the proposed mains replacement program. The cost of UAG, has been calculated at the escalated rate for Purchased Gas, as shown in Table 8-8.

Contestability Costs

For the purpose of this Access Arrangement submission, contestability costs have now all been drawn together into a common category of costs called Metering and Billing. Metering and billing costs have been escalated at the relevant rates shown in Table 8-17.

8.4 Corporate costs

As part of a larger corporate group, certain corporate functions are provided for APT Allgas through a centralised corporate body. The functions performed by this centralised group include:

- Chief Executive Officer function;
- Company Secretary function – including annual reporting, general meetings, risk management, compliance management, audit costs, directors costs and general administrative costs;
- Corporate Finance function – including, treasury, tax, budgeting, general financial accounting, general management accounting, performance reporting and financial services such general accounts payable and receivable;
- Corporate Commercial function – including investor relations and general commercial functions;
- Human Resources function – including training, health safety and environment, employee communications, payroll and recruiting;
- IT and Transformation function – including APT Allgas specific IT costs;
- Legal and Regulatory function – while general legal and regulatory costs are allocated among the corporate group using the general process, legal and regulatory matters related to a particular legal action or regulatory process are directly assigned to the particular asset; and
- Projects and Other – including ongoing business improvement projects.

Applicability of corporate costs to APT Allgas

Any Service Provider, including APT Allgas needs these functions to be performed in order to meet the following activities and obligations;[90]

[90] This listing is not an exhaustive listing of the requirements and obligations which the corporate functions undertake.

- statutory obligations such as lodging accounts, auditing accounts, reporting to shareholders, maintaining shareholder registries, holding annual general meetings, paying tax, maintaining environmental, safety and regulatory compliance;
- general prudent capital raising activities such as managing investor relations, raising equity via ASX listing and raising debt via debt market activity;
- general prudent human resource management activities such as efficiently recruiting, retaining, training, compensating and managing employees;
- general prudent financial management activities such as operating appropriate internal cost monitoring systems and performance reporting systems and operating invoice payment systems;
- general prudent risk management activities such as insuring assets and operating appropriate internal risk management and reporting systems;
- general prudent IT management activities such as implementing, maintaining and operating company wide compatible IT systems and ensuring IT security is maintained; and
- ongoing business improvement activities. APT Allgas believes that ongoing business improvement activity is implicit in the Rule 91 benchmark of a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice.

APT Allgas submits that the costs associated with these functions would be incurred by a prudent service provider, acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services, and that they are necessarily incurred for APT Allgas to provide pipeline services.

It should be recognised that other regulators, notably the ACCC, have previously approved APA general corporate costs such as corporate employee salaries, director's fees, rent, office costs, IT costs, communications costs, costs associated with stock exchange listing (eg share registry fees, annual report preparation) and other costs incurred in the operation of a listed business[91].

Consistent with the above, the corporate costs put forward by APT Allgas include costs for senior management and board, company secretary functions including shareholder management and listing, finance including tax, treasury and statutory reporting, information technology, commercial, legal, regulatory, operations management including procurement, asset management and engineering.

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[91] For example the ACCC approved APA corporate costs, such as those outlined above, on the Roma Brisbane Pipeline as submitted except for some relatively minor wage and legal costs.

8.4.1 Approach

APT Allgas is conscious that the AER is concerned about the level and nature of costs allocated to a regulated entity from related companies. APT Allgas has taken the following approach to demonstrate that the level of corporate costs allocated to is are reasonable and consistent with the requirements of Rule 91:

- Demonstrate that the aggregate corporate costs were prudently incurred

  The purpose of this stage of the approach is twofold: First, to demonstrate that these costs have been incurred within a corporate governance process that is subject to market disciplines. Second, that these costs were incurred within the spirit of the regulatory "revealed cost approach", in which the incentive of a regulated business (and indeed an unregulated business) is to reduce operating costs to the lowest sustainable level.

- Demonstrate that corporate costs were allocated on a reasonable basis and in a manner consistent with prior years

  The purpose of this stage is to demonstrate that the corporate group does not allocate costs among the operating businesses opportunistically to take advantage of particular price review processes.

- Demonstrate that the amount of costs allocated to APT Allgas is not more than would be incurred by a benchmark stand alone firm

  Directly to meet the requirements of Rule 91, APT Allgas has commissioned a benchmarking study to demonstrate that the level of corporate costs allocated to APT Allgas is not greater than the amount that would be incurred by APT Allgas were it a stand alone business.

8.4.1.1 Aggregate corporate costs prudently incurred

In preparing its regulatory accounts, APA Group must reconcile to its audited statutory accounts. The audit assurance provided on the corporate accounts demonstrates that the amount of reported corporate costs is as reported.

Inherent in that reported amount is the corporate governance process on the incurrence of those costs. The activities behind these costs are subject to a rigorous budgeting process which ensures that the activities are necessary to operate the business to provide pipeline services, and that the costs of performing these costs are not more than the lowest sustainable cost.

This is consistent with the Australian regulatory "revealed cost" methodology for determining a reasonable basis of non-capital cost forecasts. It is in the interest of any organisation, regulated or otherwise, to reduce its non-capital costs to the lowest sustainable level. This is consistent with the pricing principles encapsulated in Section 24(b)(3) of the National Gas Law.

APT Allgas considers that the starting point of this analysis, the audited corporate financial statements, provides evidence that the corporate costs were actually incurred, and that, in conjunction with the corporate governance process, that these costs are at the lowest sustainable level required to provide the pipeline services.

Corporate governance and Board budgeting process

Being incurred at the corporate level, the corporate costs are subject to a rigorous Board review and budget approval process. Some noteworthy points of this process include:

- The corporate costs are from a Board approved budget. This budget is not derived for any regulatory purpose and is independent of any regulatory process. The costs in the budget are based on internal business forecasts and represent a reasonable estimate of future costs. The costs are within the market guidance provided in accordance with ASX listing rules.

- In setting the budget costs the Board is required to act in the interests of APA shareholders; it is not in the interests of APA shareholders to have excessive costs. As such there are strong corporate governance reasons to assume these costs are prudent and efficient.

- The incentive to reduce costs is further reinforced by APA management incentive schemes. These incentive schemes are driven by a formula, the most readily controlled component of which is costs. This provides APA management with a major incentive to ensure costs are kept at an efficient level as significant personal rewards are directly linked to achieving financial targets.

The actual 2009/10 APA Group corporate costs were $47.2 million.

These costs are then allocated to APT Allgas via the allocation process described below.

8.4.1.2 Consistent allocation methodology

In the context of currently approved APA access arrangements (such as the access arrangements for the Victorian PTS, APT Allgas network, the Roma Brisbane Pipeline etc) it is in APA's interest to reduce operating costs, including corporate costs, wherever possible. APA has no incentive to increase corporate costs as to do so would increase costs to other APA regulated assets with a consequent reduction in margins. This causal nexus would not exist if different regulators used different allocation methodologies. The use of different allocation methodologies would reduce incentives to reduce corporate costs.

So long as the allocation methodology is consistent over time and across assets, the incentive mechanism is exerting a discipline on the amount of corporate costs incurred.

Furthermore, given the company-wide nature of the APA corporate costs and the asset footprint of the APA Group these costs are scrutinised, and will be scrutinised, by regulators other than the AER, notably the Economic regulation Authority of Western Australia, and will be scrutinised at each such regulatory reset.[92]

Consistency with APA Accounting Practice and Internal Cost Allocation Methodology

The allocation methodology now being put forward by APT Allgas is the same methodology as used internally in APA in deriving budgets and internal accounts. This has been confirmed by Deloitte, the auditor. The audit report and supporting working papers demonstrate that APA Group's corporate costs are being recovered from the operating assets only once.

APA has consistently applied a revenue based cost allocation methodology, and this approach continues to be used to derive regulatory accounts required by relevant national gas and electricity laws. In some instances these regulatory accounts were or are provided to regulators.[93]

If different cost allocation methodologies were to be used on different assets in the future due to jurisdictional regulatory decisions this creates the potential for inadvertent under recovery or over recovery of these corporate costs across the whole APA Group.

Consistency with Allocation Methodology accepted by the AER and ACCC for the APA Group

It is noteworthy that consistency across the corporate group effectively requires the entire group to ultimately adhere to the most restrictive regulatory requirements among the group.

As APA Group owns electricity transmission assets, the cost allocation methodology must meet the most prescriptive requirements - those applicable to electricity transmission assets.

[92] APA currently has Access Arrangement on eight heavy regulation gas assets, including APT Allgas, where such costs would be scrutinised at resets.

[93] Murraylink and Directlink regulatory accounts using this allocation methodology have all been submitted to the relevant state or Commonwealth regulators in 2006, 2007 and 2008. Note that the sale of interests in Murraylink and Directlink to EII in 2008 means that APA no longer submits these accounts, and the move to national energy regulation in 2008 means that APT Allgas regulatory accounts are no longer submitted to the Queensland Competition Authority

The revenue based methodology has been accepted by the AER and ACCC in relation to both electricity and gas assets owned, wholly or partially, by the APA Group. For example the revenue based methodology was put forward by APA in the Murraylink and Directlink cost allocation manuals, which are required by regulation, when these assets were wholly owned by APA. For example, the Directlink Manual[94] states:

> An annual cost allocation is undertaken for all shared costs arising from the provision of the above services by the APA Group. The allocation of these shared costs is made on the basis of revenue. As shown in Table 1 [of the Directlink manual], each business unit is allocated corporate overhead costs in proportion to their contribution to the APA Group's Total Revenue.
>
> Based on historical performance, Directlink believes revenue is an appropriate driver for allocating 'Corporate Overhead Costs' as corporate overheads are a necessary cost for the generation of revenue. Furthermore, a causal relationship exists between revenue generation and corporate overheads. Revenue is therefore considered an appropriate driver for the allocation of 'Corporate Overhead Costs' to each of the APA Group's assets. It should be noted that in previous gas infrastructure regulatory decisions relating to APA gas assets the ACCC has accepted revenue as an appropriate allocator for corporate costs.

The AER approved these manuals.[95] The AER's consultant in this process noted[96] that the corporate cost allocation approach was consistent with National Electricity Rules cost allocation principles.

The revenue based allocation methodology is also the same corporate cost allocation methodology used by APA in regulatory decisions for such assets as the Moomba Sydney Pipeline and the Roma Brisbane Pipeline. For example, the ACCC 2007 Draft Decision on the GasNet Access Arrangement states[97]:

> The APA Group's current approach is to allocate its corporate overheads on the basis of an asset's contribution to the APA Group's Total Revenue. In relation to its proposed revisions to the AA for the Roma to Brisbane pipeline (RBP) in 2006, the APA Group allocated 14 per cent of its indirect corporate costs to the RBP on the basis that the RBP contributed 14 per cent of the APA Group's revenue (in 2005). A similar approach was adopted by the APA Group for the Moomba to Sydney pipeline (MSP).

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[94] 2008, APA group, *Directlink Manual* page 10.
http://www.aer.gov.au/content/index.phtml/itemId/718224

[95] AER, 2008, *Final Decision Electricity Transmission Network Service Providers Cost Allocation Methodologies* August 2008 p10. http://www.aer.gov.au/content/index.phtml/itemId/718224

[96] 2008, McGrathNicol, *Review of Cost Allocation Methodology* Directlink 30 July 2008 page 11.
http://www.aer.gov.au/content/index.phtml/itemId/718224

[97] ACCC, 2007, *Draft Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System*, p116

And further supports this by noting[98]

> The APA Group's annual ring fencing reports confirm that revenue shares are used as the basis for allocating corporate overheads.

The ACCC 2008 Final Decision on the GasNet Access Arrangement[99] states GasNet has made further confidential submissions on the issue of corporate costs. These submissions allocated corporate costs on the basis of revenue attributable to particular assets. In responding to these submissions in the Final Decision the ACCC did not raise any issues concerns with the corporate cost allocation methodology.

This same revenue based cost allocation methodology has been applied in determining the share of corporate costs allocated to APT Allgas for the purposes of this access arrangement.

Based on the revenue allocation methodology outlined above, the corporate costs allocated to APT Allgas are summarised below.

The allocated corporate costs are based on the APA Group approved 2010-11 budget, adjusted by removing costs which are not related to functions provided to APT Allgas. This includes costs associated with;

- Insurance, which is recovered separately;
- Corporate development including any future mergers, acquisitions, divestments or similar corporate projects;
- IT which is attributed to a specific business unit;
- Other commercial services attributed to a specific business unit;
- APT Allgas IT costs – which are added in as a separate item;

The revenue allocator used is the budgeted revenue of APT Allgas as a percent of total APA revenue. For 2009/10, this allocator is 9.6%.

The actual APA Group corporate costs allocated to APT Allgas for 2009/10 using this methodology are $4.6 million.

[98] ACCC, 2007, Draft Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System, 2007, p116

[99] ACCC, 2008, Final Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System, 2008, P80

8.4.1.3 *Corporate cost benchmarking*

APT Allgas benefits from the centralisation of these functions - the cost to APT Allgas would be much greater if it had to source each of these functions for its exclusive use.

In order to confirm and quantify the benefits of using a centralised corporate function instead of duplicating these functions as stand alone functions for each of APA's assets, APA has commissioned a report from KPMG which examines this issue and estimates the reasonable level of non capital corporate costs for an asset with the characteristics of APT Allgas.

This KPMG report is attached at Attachment 8.1. This report effectively derives a corporate cost benchmark 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 delivering pipeline services.

The KPMG report undertakes cost modelling of the non capital corporate costs for an asset with the characteristics of the covered GGP. This modelling identifies corporate functions that would be required by an asset with the characteristics of the covered GGP and then models costs for these corporate functions. This modelling is based on a series of empirical cost benchmarks. The cost modelling is explicitly undertaken to meet the requirements of Rule 91.

The KPMG report concludes that an expected range of Non Capital corporate costs (in $2010) for an asset with the characteristics of the covered portion of the GGP is $6.08 million to $8.48 million per annum, with a midpoint of $7.2 million.[100] APT Allgas submits that this midpoint demonstrates that its submitted corporate cost of $4.5 million for 2010 demonstrates significant synergies associated with the centralisation of corporate functions. APT Allgas submits that the KPMG report strongly supports APT Allgas' position that its forecast corporate costs meet the requirements of Rule 91.

In considering the KPMG report the AER should recognise that the cost categorisations used by APT Allgas and KPMG may differ due to APA internal cost centre definitions and KPMG cost benchmarks not being aligned. However the fact that the total amount of corporate costs is similar indicates that the APT Allgas corporate costs are reasonable costs when compared with a benchmark prudent service provider, acting efficiently, in accordance with accepted and good industry practice.

APT Allgas submits that the full range of corporate overhead costs submitted by APT Allgas in its forecast of Non Capital Costs for the forthcoming Access Arrangement Period meet the prudent service provider test under Rule 91. That is, these costs be such as would be incurred by a

[100] KPMG, 2010, Corporate Cost Benchmarking – APT Allgas, page 1.

prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

8.4.2 Consistency with the National Gas Objective and the Legitimate Interests of Service Providers

APT Allgas believes that ensuring that corporate costs are recovered once, but only once, is in the interests of both the Service provider and the Users. To recommend a cost allocation methodology that increases the potential for the over-recovery or under-recovery of costs is not in the interests of either the Service Provider or the Users, and as such is not consistent with the national gas objective.

Furthermore Section 24(2)(a) of the National Gas Law requires that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services. To recommend a cost allocation methodology that increases the potential for the under-recovery of costs is not consistent with the recovery of efficient costs.

Similarly, recommending a cost allocation methodology which differs to that used in other regulatory proceedings has the potential to distort investment decisions. Such an approach may create inappropriate incentives to invest in some infrastructure assets in preference to others, depending on the treatment of costs in the relevant regulatory decisions.

Overall, the APA Group seeks to consistently apply a single cost allocation methodology across all of its operating businesses and Access Arrangements. To the extent that this consistent application is not approved across the range of regulatory processes, this raises the potential for either inadvertent under-recovery or over-recovery of corporate costs

APA has consistently used the revenue based allocation internally and in submissions to the ACCC, AER and Economic Regulation Authority.

8.4.3 Corporate costs included in non-capital costs

The corporate costs then form part of the operating costs of the business. Consistent with other operating costs, the corporate costs are subject to a cost allocation methodology by which some costs are assigned to capital projects and others recovered as operating costs.

Corporate costs are also subject to real cost escalation consistent with other non-capital costs, as outlined in section 4.5.2.1

The forecast of corporate costs included in the APT Allgas forecast of non-capital costs is shown in Table 8.16.

Table 8.16: APT Allgas Forecast Corporate Costs, $Real 2009-10, $000s

Year	2011-12	2012-13	2013-14	2014-15	2015-16
APT Allgas Corporate Costs	$1.457 m	$1.466 m	$1.483 m	$1.507 m	$1.530 m

APT Allgas submits that it has demonstrated that the categories and levels of corporate costs which APT Allgas is seeking to recover are 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 delivering pipeline services.

8.5 Summary: forecast of total operating expenditure

Table 8-17 Forecast Operating Expenditure

($m Nominal)	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Controllable Costs						
Network Operations & Maintenance	10.75	11.15	11.47	11.86	12.26	**57.48**
Marketing	1.75	1.81	1.88	1.96	2.04	**9.44**
Admin & Strategic Planning	0.75	0.94	0.98	1.22	1.27	**5.17**
Total Controllable Costs	**13.25**	**13.90**	**14.33**	**15.04**	**15.57**	**72.08**
Non-Controllable Costs						
Customer Services	0.91	0.98	1.05	1.13	1.21	**5.27**
UAG	2.59	2.79	3.15	3.21	3.24	**14.98**
Government Charges	0.54	0.61	0.63	0.66	0.69	**3.13**
Metering & Billing	1.22	1.28	1.35	1.42	1.50	**6.77**

Corporate Costs	1.46	1.51	1.57	1.64	1.70	**7.89**
Total Non-Controllable Costs	**6.73**	**7.17**	**7.75**	**8.05**	**8.34**	**38.04**
Total Operating Costs	**19.98**	**21.07**	**22.08**	**23.08**	**23.91**	**110.12**

1. Totals for forecast financial year 2012-2016 Access Arrangement Period only

This data is shown below.

Figure 8-10 Forecast Operating Expenditure

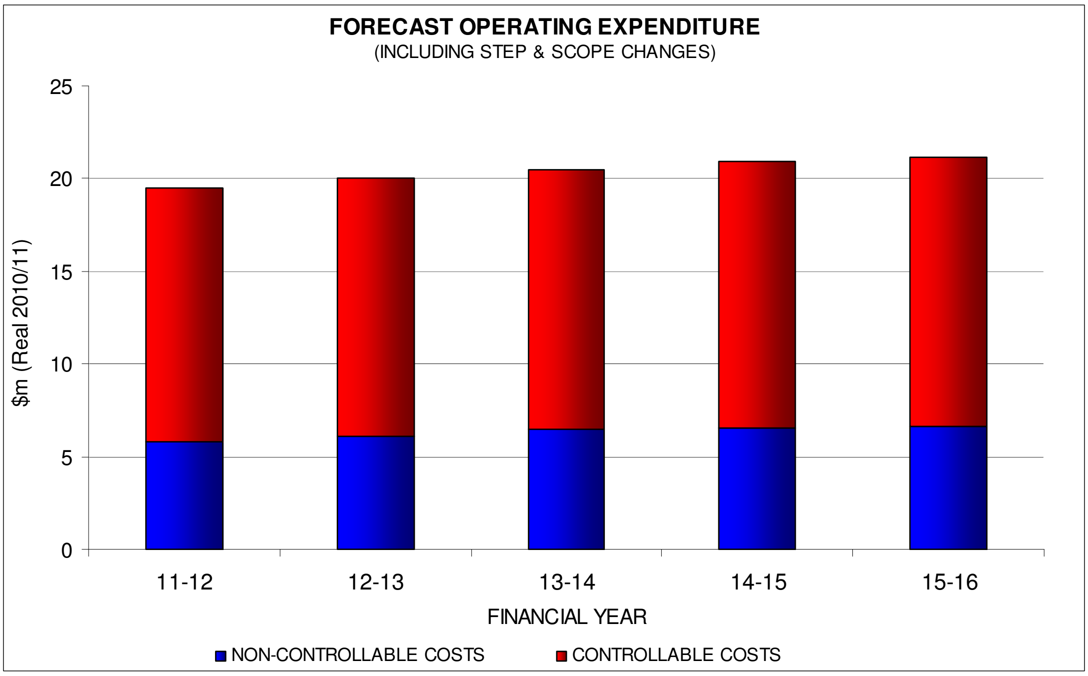


Figure 8-11 Forecast Controllable Costs

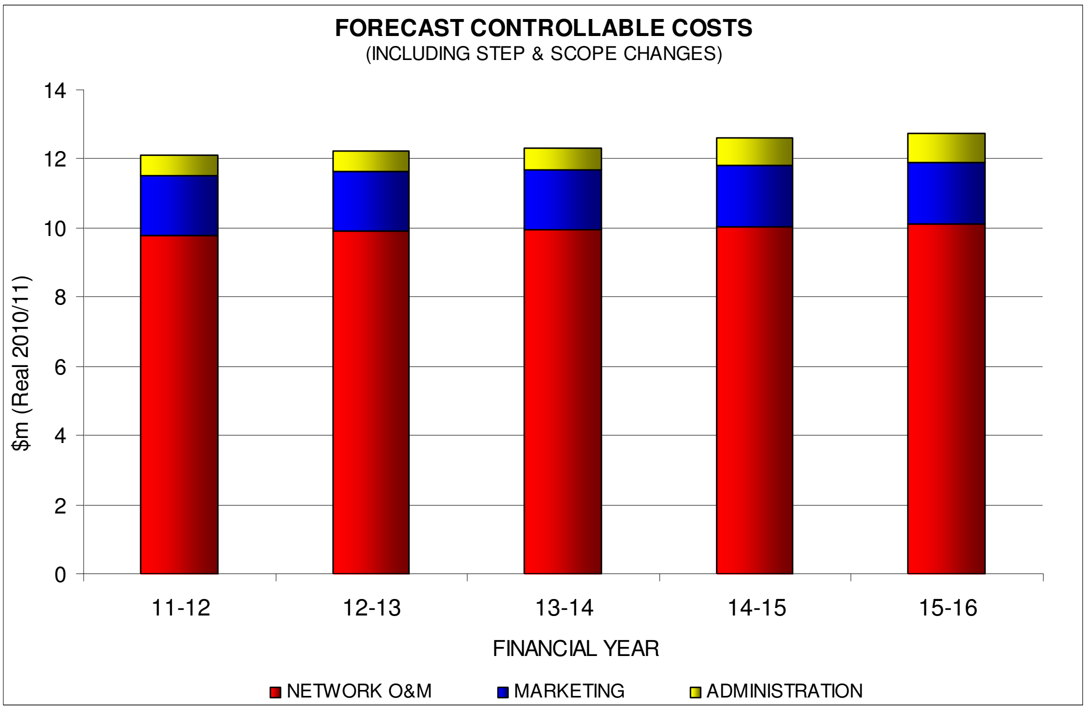
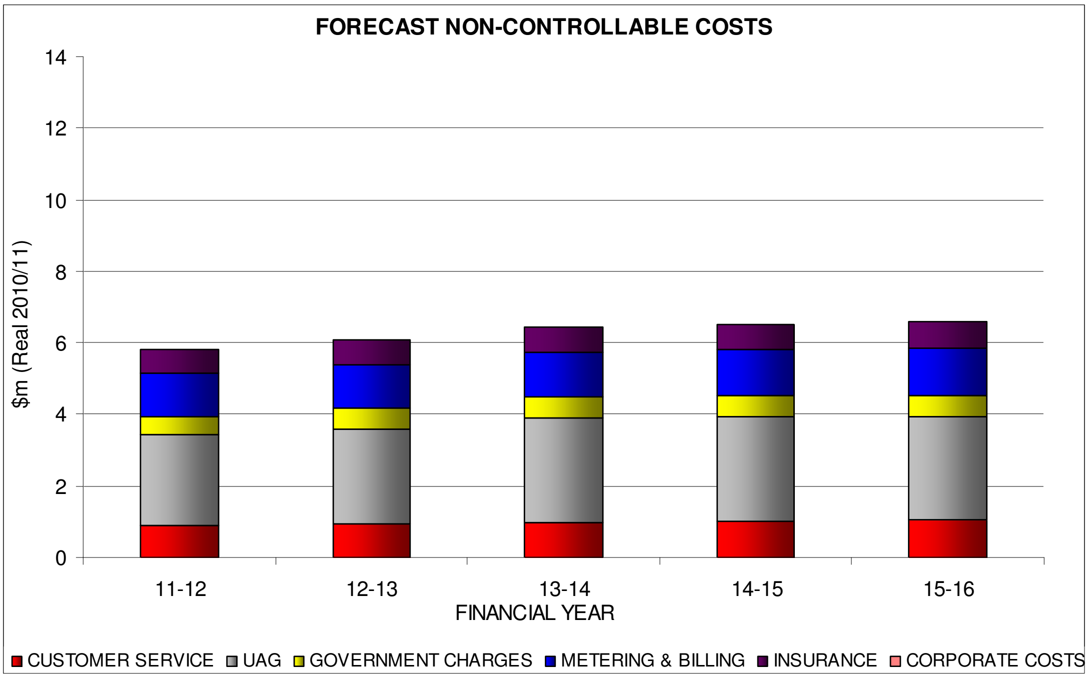
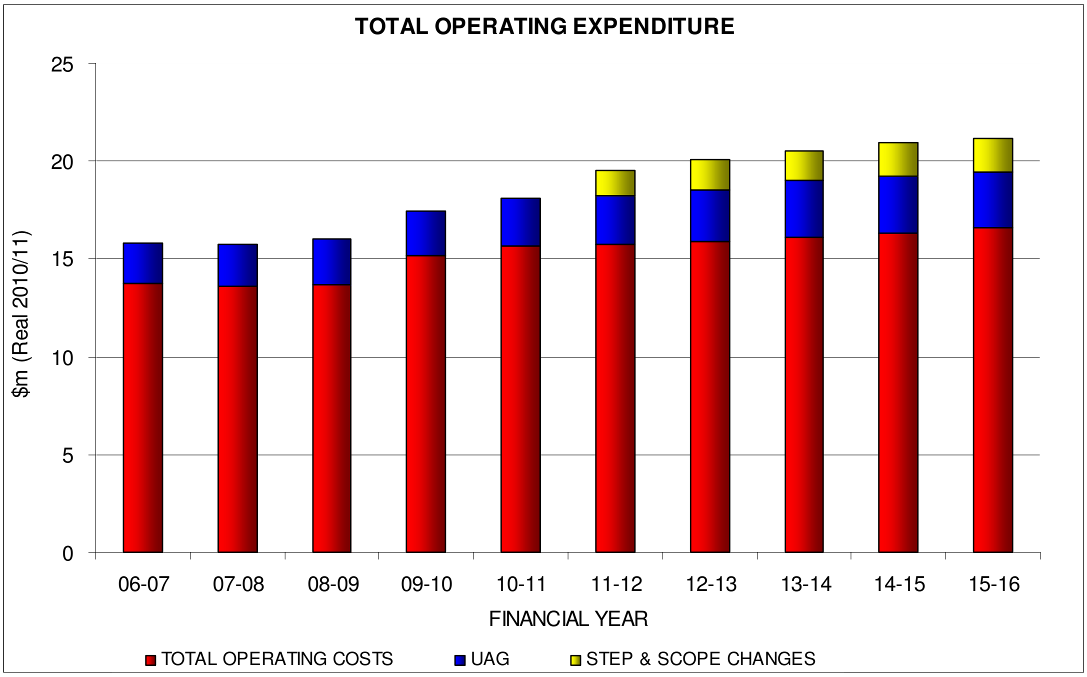


Figure 8-12 Forecast Non-Controllable Costs



A summary of historical and forecast total operating expenditure is shown below.

Figure 8-13 Total Operating Expenditure



KPIs of these forecast costs are tabulated in Table 8-18 below.

Table 8-18 Forecast Operating Expenditure KPIs

($10-11)	units	2011/12	2012/13	2013/14	2014/15	2015/16
Total Operations Costs per km Mains	$/km	6,436	6,509	6,540	6,554	6,506
Total Operations Costs excluding Scope & Step Changes per km Mains	$/km	5,602	5,649	5,607	5,643	5,624
Total Operations Costs per Consumer	$/cons	223	222	220	217	212
Total operations Costs excluding Scope & Step Changes per Consumer	$/cons	194	193	189	187	183

Table 8-19 below, shows all historical and forecast cost KPIs discussed in this submission.

Table 8-19 – Historical and Forecast Operating Expenditure KPIs

($10-11)	units	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Total Operations Costs per km Mains	$/km	5,735	5,551	5,533	5,945	6,089	6,436	6,509	6,540	6,554	6,506
Total Operations Costs excluding Scope & Step Changes per km Mains	$/km	4,976	4,795	4,716	5,179	5,270	5,602	5,649	5,607	5,643	5,624
Total Operations Costs per Consumer	$/cons	217	206	201	213	215	223	222	220	217	212
Total Operations Costs excluding Scope & Step Chnges per Consumer	$/cons	188	178	172	186	186	194	193	189	187	183

This data is presented in Figure 8-14 and Figure 8-15 below.

Figure 8-14 – Total Operating Costs per Kilometre of Mains

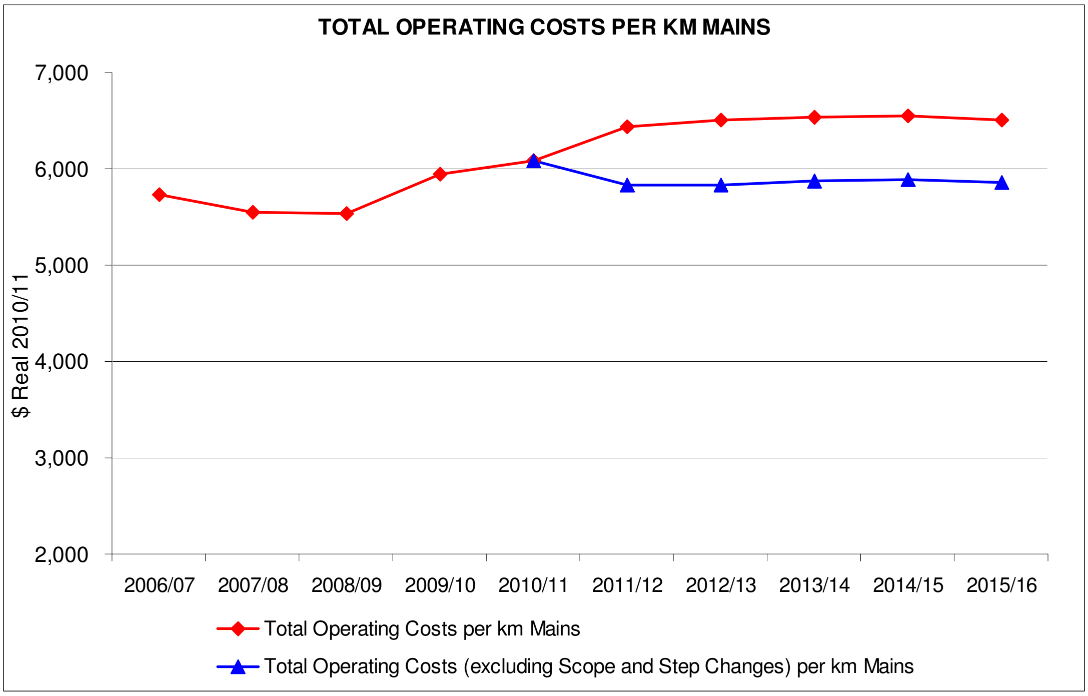
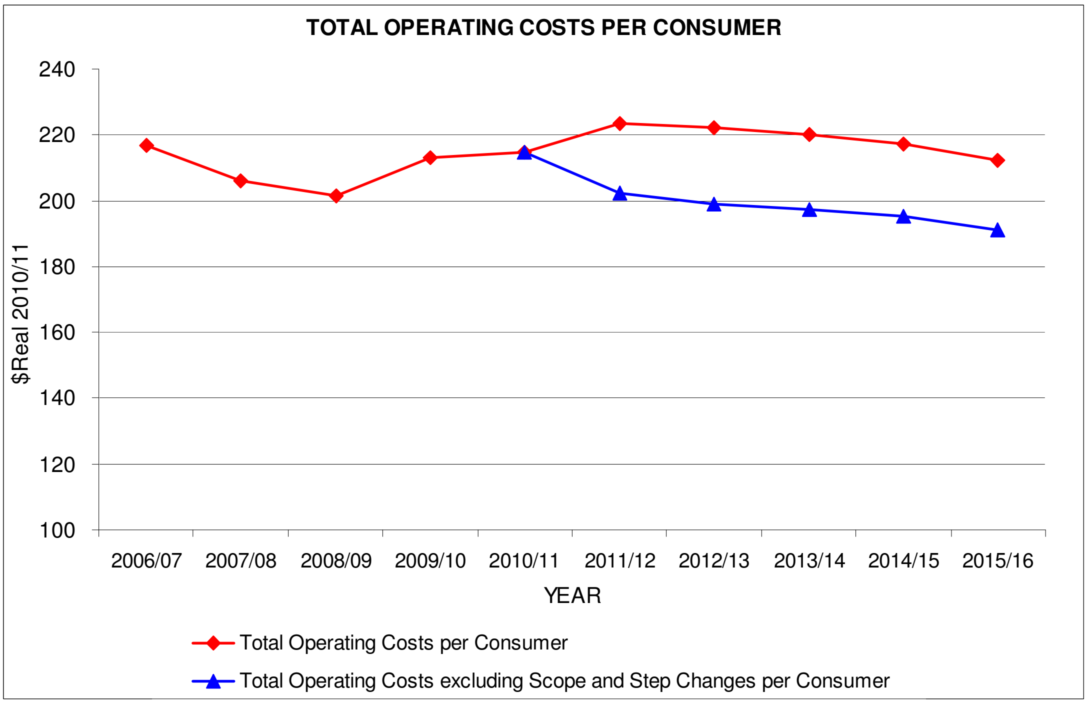


Figure 8-15 – Total Operating Costs per Consumer



From this it can be seen that the Total Operating Costs per Kilometre of Mains have increased from $5,735 in 2006/07 to a forecast $6,507 in 2015/16. This increase of $772 per kilometre, or 13.8% in real terms over this period, is equivalent to an approximate increase of 1.3% p.a. Much of this increase may be attributed to the proposed step and scope changes. However, these are deemed to be prudent expenditure.

Over the same period, Total Operating Costs per Consumer have decreased from $217 in 2006/07 to a forecast $212 in 2015/16. This modest decrease of $5 per consumer, or 2.3% in real terms over this period, is equivalent to an approximate decrease of 0.2% p.a. When the costs of the scope and step changes are excluded, the operating costs per consumer declined from $217 in 2006/07 to a forecast $191 in 2015/16. This is a decline of $26 per consumer, or 12% in real terms over this period, which is equivalent to approximately 1.1% p.a.

From this it can be seen that APT Allgas' proposed operating expenditure is aimed at ensuring ongoing network statutory compliance, compliance with relevant Australian Standards, network reliability, and prudent and efficient network operation, as the network continues to expand and be renewed over the 2011-16 AA period.

8.5.1 Opex Key performance indicators for the next AA period

Two benchmark measures are proposed for the next Access Arrangement period for APT Allgas. These are:

- Total operating costs per kilometre of mains;
- Total operating costs per consumer.

8.6 Outsourced expenditure

As APT Allgas does not contract the operation of the network to another party, it does not engage in related party outsourced expenditure within the meaning of current Australian regulatory practice.

However, APT Allgas does outsource particular functions associated with the operation of the network and with certain capital works, in order to ensure that the level of its operating expenditure is 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 delivering pipeline services.

APT Allgas has conducted a thorough public tender process to engage suitably qualified contractors to undertake capital and operational works on the network. In summary, this process involved the following processes:

- Developing the contracting strategy;
- Develop contracting scope
- Public advertisement for Expression of Interest
- A defined and rigorous tender process
- Tender assessment
- APT Board approval process
- Contract implementation
- Ongoing Contract Strategy Review

A detailed summary of this approach is included in Attachment 4.6, *Tendering processes Covering the period 01 July 2007 – 30 June 2010* relating to historical operating expenditure, and confidential Attachment 4.9, *Tendering processes Covering the period 01 July 2011 – 30 June 2016* relating to the forecast AA period.[101]

APT Allgas submits that this process has been an effective test of the market price for conducting these services, and the resulting prices represent costs 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 delivering pipeline services.

[101] This document is filed confidentially as the tender process had not closed at the time of filing. APT Allgas is concerned that public release of this document may have scope to influence the outcome of the tender process.

9 Tariffs

9.1 *Revenue Requirement*

The total revenue requirement derived from the building block approach using the PTRM is shown in Table 9-1

Table 9-1 APT Allgas Forecast Revenue Requirement ($'000 nominal)

Year	2011-12	2012-13	2013-14	2014-15	2015-16
Return on capital	43,453	46,013	48,673	51,600	54,610
Return of capital	1,911	986	911	854	1,263
O&M	19,981	21,069	22,085	23,084	23,906
Benchmark Tax liability	2,499	2,441	2,238	2,094	2,456
APT Allgas Building Block Revenue Requirement	**67,843**	**70,509**	**73,907**	**77,632**	**82,235**

9.2 *Services*

The Reference Tariffs offered by APT Allgas are designed to meet the requirement of Rule 101 in the NGR in that services that are likely to be sought by a significant part of the market.

The Reference Services derived for application under the Access Arrangement are as follows:

- Volume Customer Service
- Demand Customer Service
- Reference Ancillary Services

APT Allgas also provides prudent discount and negotiated services.

Table 9-2sets out the customer classes adopted and the definitions of the Reference Services, as defined in the revised Access Arrangement. Note that the information in Table 9-2 shows the customer class and customer numbers as at 30 June 2010.

Table 9-2 Customer Groups

Customer Group	Description/Reference Service	Number of Customers
Volume	The Volume Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas less than 10TJ per year and have an MDQ of less than 50 GJ.	81,823
Demand	The Demand Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas of at least 10TJ per year or have an MDQ of 50 GJ or greater.	102

Transaction Costs

These Reference Services were chosen to represent reasonably homogeneous groupings of End Users taking into account the consumption patterns and quantities, the connection and Metering types and End User locality while also considering pricing constraints. APT Allgas considers it would be inefficient to charge smaller End Users on capacity given the significant additional cost of interval metering required to facilitate charging. These extra costs would severely impact the competiveness of natural gas in the market and would lead to lower utilisation of services. In addition capacity charging of smaller customers would have negligible impact on network savings arising from any demand response.

Demand customers are charged based on capacity as well as location and have interval metering systems installed. These larger customers have significant impact on the network design and are better able to respond to price signals on location and utilisation.

Volume Class

APT Allgas proposes a single reference tariff for all regions which includes a standing charge and stepped throughput charge. The stepped throughput charge is structured as a decreasing block tariff with the second step starting at a consumption of 1.7GJ/day and tariff reducing to approximately 73% of the first step and the third step starting at 10 GJ/day and the tariff reducing to approximately 53% of the first step. This tariff structure has been designed to minimise administrative cost required for multiple zones and reflect the relatively high fixed cost component of providing the meter and service whilst enabling the End User to respond to price signals on consumption behaviour. For typical residential consumers the fixed component of their tariff is approximately 70% of their network charge with each incremental extra gigajoule of consumption per annum resulting in a network charge increase of approximately of 3% (or in FY11 $8.06/GJ/a +GST). This tariff structure encourages low consumption End Users to increase consumption by adding more appliances such as cooker only customers converting to gas hot water. The stepped throughput charge in turn provides incentives for business class customers to increase consumption at reduced average charges whilst reflecting their cost to serve.

Demand Class

APT Allgas has a unique situation in that the transmission pipeline is relatively close to many of its largest End Users and hence physical bypass is a real consideration. Calculations show that using average prices for the Demand Customer Service will result in some End Users receiving prices above stand-alone cost of supply, whereas others will receive prices well below the stand-alone costs. These inefficient pricing outcomes are not desirable for either APT Allgas or the End Users as APT Allgas is at risk of physical bypass and the End Users are paying an unacceptably high cost of supply. APT Allgas has therefore established pricing zones for the Demand Customer Service based on distance from the transmission pipeline:

- Brisbane – 3 Zones;
- Toowoomba – 2 Zones;
- Oakey – 2 Zones; and
- South Coast – 3 Zones.

The pricing zone Reference Tariffs for the Demand Customer Service were developed using a number of stand-alone Networks. These stand alone Networks were used to calculate the portion of the allocated costs attributable to the Demand Customer Service group in a particular supply area. This process involved:

- identifying the location of each End User within the Demand Customer Service with respect to the transmission pipeline;
- identifying the costs of an efficient stand-alone Network to supply End Users from the transmission pipeline. This involved the grouping of End Users to provide efficient infrastructure to that group of End Users; and
- computing the required revenue for each End User resulting from this efficient stand-alone Network.

9.3 Revenue and Cost Allocation Process

In the 2006-11 AA submission APT Allgas assigned the Total Revenue to the customer service groups using a cost allocation process. This process involved the following main steps:

- determine Total Revenue for each year using the PTRM;
- capital, operating and maintenance costs relating to the Network assets are divided into cost pools based on defined asset groups;
- customer groups (and thus the tariff categories) are defined based on consumption levels, allocated connection infrastructure and location;
- the costs for the End Users from the Demand Customer Service group are deducted based on stand-alone pricing principles; and
- the remaining costs are allocated based on asset usage.

Analysis of the network configuration and customer profile indicates that the network has remained largely the same as when this analysis was completed and approved and as such APT Allgas has relied on this analysis and escalated tariff evenly across classes.

Reference Tariffs are designed to recover the Total Revenue allocated to each customer service group based on the forecast utilisation and customer growth and as such no shortfall in revenue is proposed under Rule 94(5).

This Total Revenue apportionment and cost allocation approach ensures that the revenue derived from the application of the Reference Tariffs (modelled using the forecast load and customer growth) is equal to the Total Revenue should the assumptions regarding costs and demand growth hold.

Table 9-3: APT Allgas Forecast Revenue Requirement ($'000 nominal)

Year	2011-12	2012-13	2013-14	2014-15	2015-16
APT Allgas Revenue Requirement	67,843	70,509	73,907	77,632	82,235
Less Forecast Reference Ancillary Service Revenue	624	645	667	689	712
Less Forecast Capital Contribution Revenue	583	612	643	676	715
Reference Tariff Revenue Requirement	**66,636**	**69,252**	**72,596**	**76,267**	**80,808**

The net present value of the reference tariff revenue stream when discounted at the nominal vanilla WACC of 10.3% is $272.5 million.

Table 9-4 details the proposed revenue expected from each customer class at expected load and demand forecasts.

Table 9-4 APT Allgas Proposed Reference Tariff Revenue Stream ($'000 nominal)

Year	2011-12	2012-13	2013-14	2014-15	2015-16
Demand Class Revenue	17,301	19,103	21,124	22,740	23,435
Volume Class Revenue	41,429	47,214	53,798	59,766	63,303
Proposed Reference Tariff Revenue	**58,730**	**66,317**	**74,921**	**82,507**	**86,738**

Note: The Demand Class revenue forecasts include prudent discount and negotiated service revenues as submitted to the AER in Confidential Attachment 9.1

The net present value of the reference tariff revenue stream when discounted at the nominal vanilla WACC of 10.3% is $272.5 million which is equal to the revenue requirement.

9.4 Standalone and Avoidable Costs

Approach

Stand alone and marginal costs together must equate to the total revenue requirement. APT Allgas have estimated the stand alone cost of the Demand Class customer group based on an engineering assessment of the optimised bypass costs required to supply this class and we assume that the balance to the total revenue requirement is the avoidable cost of serving the Volume customer class.

In accordance with Rule 94 of the NGR, the revenue expected to be recovered must lie between the standalone cost of providing the reference and the avoidable cost of not providing the service.

Demand class stand alone costs

APT Allgas had 102 Demand customers in 2010. APT Allgas' engineering assessment for the network assets needed to supply these customers is as follows:

- on a pure stand-alone cost basis total asset value is $545.4 million; and
- the group stand-alone cost basis total asset value is $181.7 million.

To set the maximum revenue to be collected from the Demand customers, the group stand-alone cost asset value is used. This approach assumes the optimised network construction cost to supply groups of Demand Class customers based on location and results in the lowest capital cost required to supply all customers in that class. The asset value is then converted to an annuity using a nominal vanilla WACC of 10.3%, and standard asset lives for each category of asset. An estimate of annual operating and maintenance costs is then derived by applying a rate of 3% to the capital cost. For 2011-12, the maximum amount of revenue to be earned from the Demand customer group on a standalone cost basis is $23.6 million.

Volume class avoidable cost

APT Allgas has assumed that the Volume Class avoidable cost is the difference in total revenue requirement and the Demand Class standalone cost which for 2011-12 equals $35.1 million.

Demand class avoidable costs

The avoidable costs for the Demand Class customer group is taken to be the operating and metering telemetry cost associated with this customer group which are forecast at $0.3 million for 2011-12. This assumes that the cost saving from downsizing the steel section of the network to supply Volume Class customers only is negligible.

Volume class stand alone cost

APT Allgas has assumed that the Volume Class standalone cost is the difference in total revenue requirement and the Demand Class avoidable cost which for 2011-12 equals $58.4 million.

Outcome

Table 9-5 shows that the expected revenue for 2011-12 complies with Rule 94.

Table 9-5 APT Allgas Avoidable and Standalone Costs 2011-12 ($'000 nominal)

Year	Avoidable Cost	Expected Revenue	Standalone Cost
Demand Class Revenue	337	17,301	23,631
Volume Class Revenue	35,099	41,429	58,393

9.5 Long Run Marginal Costs

Rule 94 of the NGR requires long run marginal costs to be taken into account when designing tariffs. Long run marginal costs include the incremental capital and operating costs required to connect a new customer. APT Allgas has analysed the proposed capital expenditure for customer requested and augmentation over the 2012-16 AA period and compared the tariff revenue from the incremental new connections and capital contributions to the required payment using a net present value analysis. The resulting analysis shows that on an overall basis the revenue derived from forecast new connections over the 2012-16 AA period exceeds the costs required to meet the capital and maintenance required to connect these customers. This analysis assumes a rate of return equal to the nominal vanilla WACC of 10.3%, assumed operating costs of 3% of capital and an analysis period of 20 years.

The NGR requirements also call for individual tariff components to reflect the long run marginal costs associated with provision of that service component. In carrying out this analysis APT Allgas has focused on the Volume Class as new connections for Demand Class are few, have very specific demand requirements and are location specific. As such capital contributions are analysed on a case by case basis at the time of connection to ensure that capital and operating costs for each individual connection are recovered over a suitable period.

In order analyse the individual Volume tariff components APT Allgas has analysed the indicative long run marginal cost to connect typical customer groups in the Volume Class using FY12 estimates of connections costs and calculated the required return by applying a rate of return assumed to be the nominal vanilla WACC of 10.3% and an analysis period of twenty years. This analysis considers the incremental connection costs of the meter and service and makes no provision for mains and upstream augmentation costs. The following table details the results of this analysis and the forecast revenue associated from these customer groups.

Table 9-6: APT Allgas Volume Class LRMC

Customer Group	Consumption	LRMC (Meter & service)	Expected Revenue
Low Usage Residential Customer	3 GJ/a	$85.50/GJ/a	$76.99/GJ/a
Av. Residential Customer	10 GJ/a	$25.65/GJ/a	$29.52/GJ/a
Av. Business Customer	423 GJ/a	$4.2/GJ/a	$9.65/GJ/a

Based on this analysis it can be seen that new connections for both residential and business class customers at expected average volumes generate a revenue stream greater than that required to service the capital cost of the meter and service along with associated maintenance costs and in addition contribute to upstream augmentation costs. This reflects the minimal increase in upstream capacity required to service residential customers and the proportionally higher costs required to increase business consumers.

Lower consumption customers (cooker only) consuming around 3 GJ/a are shown to generate revenue slightly below their LRMC. APT Allgas has been progressively addressing this issue by increasing the standing charge component of the Volume tariff at a higher rate than the overall tariff to minimise the impact on existing lower consumption customers which would result in them disconnecting from the network and lead to higher overall tariffs for this class of customer. APT Allgas also discourages new connection of cooker only customers by applying a capital contribution to such new connections to ensure they are economically viable.

The Volume tariff structure has been designed to reflect the fixed cost component of service and meter costs as well as fixed non capital costs such that the throughput component contributing to upstream network augmentation required to service the higher throughputs.

9.6 Prudent Discounts

APT Allgas currently has a number of prudent discount and negotiated service End Users. Details of these have been submitted to the AER for approval in confidential attachment 9.1[102]

9.7 Ancillary services

APT Allgas offers three Reference Ancillary Services based on User requirements. APT Allgas costed Reference Ancillary Services on a cost recovery basis and forecast activity levels based on historical analysis. Forecasts of customer contributions have been escalated in line with CPI and forecast connection rates and Reference Ancillary Service volumes escalated in accordance with overall customer numbers. Table 9-7 details the proposed charges, volumes and revenues for these activities;

[102] This Attachment is Confidential as it contains commercial information relating to particular end users.

Table 9-7 Reference Ancillary Service and Customer Contribution Revenue Forecasts

($'000 nominal)	2011-12	2012-13	2013-14	2014-15	2015-16
Inlet Disconnection	38	39	41	42	43
Inlet Reconnection	42	44	45	47	48
Special Meter Read	544	562	581	600	620
Total Reference Ancillary Services	**624**	**645**	**667**	**689**	**712**
Customer Contributions	**583**	**612**	**643**	**676**	**715**

9.8 Reference Tariff variation

APT Allgas proposes to revise its reference tariff variation mechanism included in the previous AA. The need to do this arises largely due to changes in relevant provisions in the NGR compared to the former National Gas Code.

Rule 97 provides that reference tariffs may vary during the AA period pursuant to a number of methods as set out in that Rule. APT Allgas has included two reference tariff variation mechanisms in its AA:

(a) an annual scheduled Reference Tariff adjustment formula mechanism - which applies in respect of each year during the Access Arrangement Period; and

(b) Cost Pass-Through Reference Tariff variation mechanism under which APT Allgas may seek to vary one or more of the Reference Tariffs.

This is similar to the previous AA where reference tariffs were adjusted by CPI and by uncontrollable costs, referred to as *imposts*.

In deciding whether a particular reference tariff variation mechanism is appropriate, the AER must have regard to[103]:

- the need for efficient tariff structures;
- the possible effects of the tariff variation mechanism on administrative costs of the AER, the service provider, and users and potential users;
- the regulatory arrangements applicable in the previous AA; and
- the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

APT Allgas submits that its proposed reference tariff variation mechanism is consistent with the requirements of Rule 97.

9.8.1 Annual Reference Tariff adjustment formula mechanism

Rule 97(1)(b) states that a reference tariff variation mechanism can provide for the variation of a reference tariff in accordance with a formula set out in the AA.

APT Allgas' previous AA included an annual tariff variation formula in its tariff variation mechanism to vary all prices by CPI, and Volume and Demand customer tariffs by an additional fixed X factor. The CPI component adjusted tariffs by the

[103] Rule 97(3)

change in CPI published in the quarter immediately preceding the scheduled tariff change. The X factor was intended to rebalance tariffs towards cost reflectivity.

APT Allgas proposes to retain its annual tariff variation adjustment formula for the forthcoming AA period and add an additional parameter for Demand and Volume customer tariffs to adjust for UAG costs as described below, leading to an annual adjustment to Demand and Volume customer service reference tariffs by:

- changes in the Consumer Price Index (CPI);
- differences between forecast and actual UAG procurement costs for the coming year; and
- an X factor.

The CPI adjustment formula remains unchanged from the previous AA and leads to a simple CPI adjusted price path over the access arrangement period. The CPI formula is also similar to that recently approved by the AER for the Jemena Gas Network access arrangement.[104]

The UAG adjustment factor is intended to account for differences between forecast and actual market prices incurred by APT Allgas in procuring UAG over the access arrangement period. The price paid for UAG is not a factor that can be controlled by APT Allgas.

The actual market price paid by UAG could vary considerably over the AA period. In particular, new gas developments such as the potential for export of LNG from coal seam methane reserves could see gas prices rise considerably in the later years of the AA period. However in the absence of such developments prices may remain relatively stable. This uncertainty appears to be priced into longer term contract offers obtained by APT Allgas for UAG over the access arrangement period.[105]

APT Allgas considers that using the quoted prices to calculate UAG costs for the AA period risk customers paying too much for UAG if potential gas developments do not eventuate. Conversely, keeping UAG procurement costs in line with current costs would risk under-compensating APT Allgas for its efficient costs in procuring UAG should they rise significantly. APT Allgas considers that neither of these outcomes would be consistent with the National Gas Objective and the Revenue and Pricing Principles.

APT Allgas therefore proposes that Demand and Volume Customer Service tariffs be varied each year of the access arrangement period on 1 July by the difference between forecast UAG procurement costs included in revenue for the upcoming

[104] AER 2010, Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015, June

[105] Details of these contract offers are confidential, and are provided to the AER as a confidential attachment to this submission.

regulatory year and actual UAG procurement costs that will be incurred in that regulatory year. Actual UAG costs for the coming regulatory year will be known in time to make this adjustment as contracts for the forthcoming year will need to be in place before the year begins. APT Allgas will remain exposed to UAG volume risk as it does not propose to adjust tariffs to reflect actual UAG volumes from year to year. Only Demand and Volume Customer Service tariffs are proposed to be varied by this UAG factor as these services relate to network throughput and are therefore related to the total amount of UAG incurred.

APT Allgas notes that this mechanism is consistent with the mechanism in place for ActewAGL in respect of the ACT gas distribution network, where the AER approved a cost pass through mechanism for the ACT network that operates in essentially the same way to the formula proposed by APT Allgas.[106] APT Allgas considers that its proposal will lead to lower administrative costs compared to that approved for ActewAGL, however, as:

- UAG costs for the coming regulatory year will be able to be readily verified through contracts procured in a competitive market; and
- no adjustment to revenue is required compensate for any lag in recovery or return of adjusted costs to customers.

APT Allgas has retained the X factor adjustment in its annual tariff variation adjustment formula. The X factor only applies to Demand and Volume Customer Service tariffs and smooths required tariff increases over the access arrangement period to minimise annual price increases experienced by End Users.

APT Allgas submits that its proposed annual reference tariff adjustment formula mechanism is consistent with Rule 97(3) as it:

- ensures that tariffs move with changes in CPI[107];
- is readily verifiable by external parties, including users and prospective users, thereby reducing compliance costs[108];
- is consistent with the previous APT Allgas AA, in providing for the annual adjustment of Reference Tariffs in accordance with movements in CPI[109]; and
- is consistent with recent AER decisions for AAs applying to similar services, for example in relation to the Jemena Gas Networks (JGN) NSW gas distribution networks[110].

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[106] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.23

[107] Rule 97(3)(a)

[108] Rule 97(3)(b)

[109] Rule 97(3)(c)

9.8.2 Cost pass-through reference tariff variation mechanism

Rule 97(1)(c) specifically allows a service provider to include in the AA a reference tariff variation mechanism that allows tariffs to vary as a result of a cost pass-through for a defined event. APT Allgas proposes to include a cost pass through reference tariff variation mechanism in the AA to ensure APT Allgas can recover incremental costs resulting from material unforeseen or uncontrollable events.

APT Allgas has not included specific defined cost pass-through events in the AA. It has instead elected to define cost pass-through events in general terms as those events that are uncontrollable, and that are unforeseen or not able to be accurately forecast at the time the AA is approved, that lead to or are expected to lead to material changes in costs that are not already included in reference tariffs. APT Allgas considers that this approach reflects the practicalities of cost pass through events in that they are usually unforeseen, as well as recent regulatory practice by the AER.

Drafting multiple cost pass-through event definitions to capture a broad range of possible outcomes risks not allowing the recovery of costs associated with an otherwise legitimate event due to the limitations of foresight, as recognised by the AER in respect of the ACT 2009-14 electricity distribution determination:

> Unforeseeable events are not easily defined. Therefore, rather than attempting to specifically define all unforeseeable events that could occur during a regulatory control period, the AER considers it is appropriate to define a general set of circumstances, the occurrence of which will constitute a general pass through event.[111]

The AER also noted that an inability to recover costs associated with a material cost pass-through event is likely to impact on a regulated business' viability:

> If an unforeseeable and uncontrollable event would have a material impact on a DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and NER, it is appropriate that costs associated with the event should be passed through to consumers.[112]

APT Allgas agrees with this conclusion and considers that it has equal applicability to gas network service providers in providing reference services.

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[110] Rule 97(3)(d)

[111] AER 2009, Australian Capital Territory distribution determination, 2009-10 to 2013-14: Final Decision, p 128

[112] AER 2009, Australian Capital Territory distribution determination, 2009-10 to 2013-14: Final Decision, p 128

APT Allgas also notes that its proposed approach is consistent with the revenue and pricing principles under section 24 of the NGL that require a service provider to be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services or complying with a regulatory obligation or requirement.[113] Arbitrarily limiting the recovery of costs associated with uncontrollable and unforeseen or unforecastable events due to limitations in foresight on the part of either the service provider or the AER would not be consistent with this principle.

The AER's recent regulatory practice supports APT Allgas' proposed approach. The AER has approved a general cost pass through event in each of its distribution network decisions made under the National Gas Law and National Electricity Law.[114] At the same time, the AER has rejected a number of specific defined pass through events proposed by various proponents in favour of a general pass through event.[115] APT Allgas also notes that this approach is consistent with the regulatory arrangement in the previous AA where cost pass-through events, or *imposts*, were not specifically defined.

While not defining individual cost pass through events, APT Allgas has included some examples in the AA to assist the AER and users to understand the expected scope of the cost pass through reference tariff variation mechanism. The examples included in the AA are:

- Changes in regulatory obligations, or the imposition of any new regulatory obligations, including changes to applicable laws, rules and regulations;
- A change in tax, or the imposition of a new tax;
- An unusual or foreseen event, such as a bushfire or earthquake, that leads to costs not otherwise recovered or recoverable through insurance or other compensation payments;
- The implementation of the National Energy Customer Framework within the APT Allgas network area;
- The introduction of a carbon pollution reduction scheme, or similar scheme intended to impose a cost on carbon; and
- An expansion of the Short Term Trading Market to include the APT Allgas network, or that requires APT Allgas to participate in that market.

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[113] NGL section 24(2)

[114] For example, a general cost pass through event was included in the NSW and ACT electricity determinations, the Jemena NSW, Country Energy Wagga Wagga and ACT access arrangements and the Queensland electricity determinations.

[115] AER 2009, Queensland draft distribution determination 2010-11 to 2014-15, November, pp 344-6

APT Allgas notes that each of these 'events' have been approved as specific pass through events for other service providers, including Jemena in respect of its NSW gas network[116], and ActewAGL Distribution for its ACT network.[117]

APT Allgas submits that its proposed cost pass-through Reference Tariff variation mechanism is consistent with Rule 97(3) as it:

- ensures that tariffs reflect the efficient costs of providing reference services by providing a mechanism to allow unforeseen and uncontrollable costs to be reflected in reference tariffs[118];
- is simple to understand and not burdened by legal jargon making it easier to comprehend and apply, thereby reducing compliance costs[119];
- is consistent with the previous APT Allgas AA, in providing for a general cost pass through event definition[120]; and
- is consistent with recent AER decisions for similar services[121].

9.8.3 Materiality threshold

As noted above, Rule 97(3) includes considerations for the AER in approving a reference tariff variation mechanism. In particular, 97(3)(b) states that the AER must have regard to "the possible effects of the mechanism on administrative costs of the AER, the service provider, and users or potential users".

APT Allgas proposes two separate materiality thresholds to apply, depending on the nature of the cost pass through claim: one referable to the power of the change in cost in question to drive a change in tariff; and the other defined as a percentage of revenue.

The AER stated in its recent decision for the ACT gas distribution network that:

> …the AER considers that a lower threshold should apply for taxation events, in addition to the regulatory and UAG costs. This is because the efficient costs

[116] AER 2010, Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015, June, clause 3.5C

[117] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.24

[118] Rule 97(3)(a)

[119] Rule 97(3)(b)

[120] Rule 97(3)(c)

[121] Rule 97(3)(d)

for these events can be readily verified by information from the relevant taxing or regulatory authority.[122]

The AER subsequently approved a materiality threshold defined in terms of the power of the change in cost in question to drive a change in tariff.[123]

In line with this decision, APT Allgas proposes that for cost pass-through events where:

- the change in reference tariff is notified to occur that the same time as annual CPI adjustment; and
- the actual or forecast change in costs associated with the cost pass through event can be readily verified by documentation (for example invoices, contracts or independently audited information);

the relevant materiality threshold should be that the change in cost is sufficient to change the smallest increment in the relevant reference tariffs expressed to the number of decimal places as that tariff is presented in the AA.

This approach recognises that there is a minimum amount of change in costs that can be meaningfully reflected in tariffs. For example, a very small change in costs, when allocated to tariffs, is likely to lead to such a small change in tariffs that rounding means that no change can be effectively made. This represents a natural materiality threshold for cost pass-through events that are otherwise expected to lead to low administrative costs for the AER, APT Allgas and users in their analysis and application, as outlined below.

The proposed materiality threshold encourages tariff variations arising from cost pass-through events to be reflected in tariffs at the same time as tariffs are adjusted for CPI, potentially limiting tariff changes to once a year. This limits the administrative costs borne by the AER, APT Allgas and users from multiple tariff changes in a year which arise from the preparation of tariff variation notifications, the assessment of tariff variations, the publication of varied tariffs, and the change in contracts with users to reflect the change.

In addition, the threshold reflects the low administrative costs expected to be associated with cost pass through claims that can be readily verified by documentation such as invoices or contracts. A simple verification process means that the AER's and APT Allgas' administrative costs in assessing a proposed tariff variation are significantly reduced. This approach also encourages APT Allgas to

[122] AER 2009, ActewAGL Access Arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015: Draft Decision, November, p 162

[123] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.24

provide clear verifiable information to the AER to support its cost pass through claims.

For all other cost pass-through claims, APT Allgas proposes that the materiality threshold be set at one per cent of the smoothed revenue requirement specified in the final decision in the years of the access arrangement period that the costs are incurred. This threshold is consistent with that approved by the AER for other service providers, including Jemena in respect of its NSW gas network[124], and ActewAGL Distribution for its ACT network.[125]

APT Allgas submits that its proposed materiality threshold is consistent with Rule 97(3) as it:

- ensures that tariffs reflect the efficient costs of providing reference services by providing a mechanism to allow unforeseen and uncontrollable costs to be reflected in reference tariffs[126];
- establishes materiality thresholds for cost pass through claims that reflect the administrative costs expected to be incurred by the AER, APT Allgas and users in assessing claims changing tariffs[127];
- is consistent with the previous APT Allgas AA which limited claims for imposts to those that were 'material[128]; and
- is consistent with recent AER decisions for similar services[129].

9.8.4 Tariff variation process

A key change in APT Allgas' AA is in the tariff variation process. The former National Gas Code included a process for assessing tariff variations that is not reproduced in the National Gas Rules.[130] It is therefore necessary to include a tariff variation process in the APT Allgas AA. APT Allgas has designed the tariff variation process in the AA to give the AER adequate oversight and powers of approval over variations to the reference tariffs, as required under Rule 97(4).

APT Allgas proposes a tariff variation process whereby annual changes in CPI are notified to the AER at least 40 business days before they are scheduled to take

[124] AER 2010, Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015, June, clause 3.4(f)(iv)A
[125] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.24
[126] Rule 97(3)(a)
[127] Rule 97(3)(b)
[128] Rule 97(3)(c)
[129] Rule 97(3)(d)
[130] National Gas Code sections 8.3 -8.3H

effect. This notification may also include the impact of one or more cost pass-through events, however cost pass-through events may also be notified to the AER at any other time.

Each tariff variation notification will include information on how the change in reference tariffs has been calculated, and if applicable, how any relevant change in costs associated with a cost pass-through event have been derived or estimated. This information must be sufficient to allow the AER to verify the materiality of the change in costs associated with a cost pass-through event, and how the change in costs is reflected in reference tariffs. The AER can therefore consider all proposed tariff variations to ensure they are compliant with the tariff variation mechanism in the AA and relevant Rule requirements.[131]

The AER must notify APT Allgas of its decision in respect of a tariff variation notification (relating to a CPI adjustment, a cost pass-through event or both) within 30 business days of receiving a notification. This timing is consistent with recently approved access arrangements for the NSW and ACT gas networks.[132] The AER's decision may relate to tariffs to be varied in line with the annual CPI tariff variation process, or at any other time during the AA period.

If the AER does not make a decision within 30 business days, APT Allgas proposes that relevant reference tariffs be automatically varied in accordance with the notification given by APT Allgas. However, if the AER subsequently decides against all or part of the variation, the AER may require APT Allgas to amend reference tariffs to take account of the AER's decision. A decision of this kind should leave APT Allgas economically neutral compared with a situation in which the AER's decision had been implemented in accordance with the APT Allgas notification. This automatic variation provision is essentially identical to that approved by the AER to apply in the ActewAGL Distribution ACT access arrangement.[133]

This approach ensures that tariff variations occur in line with industry expectations, for example that CPI adjustments occur on 1 July. In this way it limits administrative costs for APT Allgas and users as it provides predictability as to the timing of annual tariff changes.

The approach also provides certainty to APT Allgas that costs associated with cost pass-through events are able to be recovered within a reasonable amount of time, ensuring that reference tariffs are set so as to give APT Allgas a reasonable opportunity to recover at least the efficient costs it incurs in providing reference

[131] Rule 97(4)

[132] AER 2010, Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015, June, clause 3.4(d); AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.7 and 6.16

[133] AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.17 and 6.18

services or complying with a regulatory obligation or requirement.[134] Delays in recovering costs, particularly where they relate to a significant event, could undermine APT Allgas' ability to deliver reference services in the future.

APT Allgas submits that its proposed tariff variation process is consistent with Rules 97(3) and (4) as it:

- ensures that tariffs reflect the efficient costs of providing reference services by providing a mechanism to allow unforeseen and uncontrollable costs to be reflected in reference tariffs[135];
- provides a simple administrative process that gives the AER adequate oversight of tariff variations, while also providing predictability in the timing of tariff variations, thereby limiting administrative costs of the AER in assessing claims and of APT Allgas and users in giving effect to tariff variations[136];
- is consistent with recent AER decisions for similar services[137]; and
- provides the AER with adequate oversight and powers of approval over the variation of reference tariffs.

[134] NGL section 24(2)

[135] Rule 97(3)(a)

[136] Rule 97(3)(b)

[137] Rule 97(3)(d)