ActewAGL Distribution

Access arrangement information for the ACT, Queanbeyan and Palerang gas distribution network

June 2009

Required by Rule 43 (1) of the National Gas Rules 2008

ActewAGL
Always.

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Access Arrangement Information
for the ACT, Queanbeyan and Palerang Gas Distribution Network

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Required by Rule 43(1) of the *National Gas Rules 2008*

ActewAGL Distribution partners are
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Jemena Networks (ACT) Pty Ltd (ABN 24 008 552 663)
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Overview

ActewAGL Distribution is required to submit proposed revisions to the full access arrangement applying to its natural gas distribution network in the Australian Capital Territory (ACT), Queanbeyan City and the Palerang Shire by 30 June 2009. The network currently comprises over 4,200 km of mains of various diameters, approximately 100 facilities of various sizes for receiving, regulating and pressure reduction (including custody receipt from the Eastern Gas Pipeline and Moomba to Sydney Pipeline) and more than 112,000 industrial and commercial and residential sites.

The National Gas Rules (NGR) require a service provider to submit with its access arrangement proposal *access arrangement information for the access arrangement proposal*. This document fulfils the requirement for access arrangement information, defined by the NGR as the information reasonably necessary for users to understand the background, and basis and derivation, of the various elements of the access arrangement or access arrangement proposal. This document also addresses relevant requirements of the Regulatory Information Notice under the National Gas Law (NGL) served on ActewAGL Distribution by the Australian Energy Regulator on 11 May 2009.

ActewAGL Distribution is not proposing to substantially change its access arrangement from that in the earlier access arrangement period. Terms and conditions of access to the network remain largely unaltered and changes mostly reflect changed requirements from those of the former Gas Code to those of the NGL and NGR. Proposed changes to non-tariff elements of the access arrangement are summarised in chapter 12 of this access arrangement information.

The reference tariff structure applying in the earlier access arrangement period has been retained. Some changes are proposed to the tariff variation mechanism (in relation to cost pass through and an adjustment mechanism for unaccounted for gas and specified fees, taxes and levies), to ensure that the impacts of ongoing developments in the regulatory framework and gas market can be appropriately managed.

Context for the review

During the access arrangement period, ActewAGL Distribution faces a number of key issues affecting natural gas demand and supply relevant to the access arrangement proposal. These include:

- The impact of the global financial crisis on input costs, demand and the weighted average cost of capital;
- Implementation of the Australian Government's carbon pollution reduction measures and related federal and jurisdictional initiatives, and their effect on inputs costs and demand;

- Security of supply concerns, with a resultant proposal for looping the Hoskinstown to Fyshwick trunk main to create storage capacity to overcome supply shortages during the winter peak period;
- Expected impacts of the proposed short term trading market for gas; and
- The introduction of new laws and rules governing the relationships between network operators, retailers and end use customers.

These issues change current arrangements and costs, or require regulatory safeguards to manage uncertainty during the access arrangement period. Alongside forecast costs and recognition of risks, ActewAGL Distribution proposes appropriate pass-through events under the tariff variation mechanism in part 6 of the access arrangement proposal and discussed in section 11.3.2 of this access arrangement information.

Demand

Tariff demand on the network during the earlier access arrangement period was approximately 3 per cent below, while peak load measured by maximum daily quantity was between 8 and 23 per cent above, that allowed in the 2004 access arrangement.

The number of residential customers receiving gas via ActewAGL Distribution's network is expected to grow by nearly 15 per cent during the access arrangement period. This increase is driven by both the connection of new dwellings and the conversion or connection of existing dwellings. Because new customers are shown to consume less than existing customers, the total growth in gas volumes at 2.5 per cent over the access arrangement period, an annualised rate of 0.5 per cent, is significantly lower than the customer growth rate. The forecast growth in volumes is also lower than the annualised growth rate of 1.3 per cent during the earlier access arrangement period. Approximately one third of the forecast increase in demand is driven by contract customers.

The forecasts include the effects of the proposed Carbon Pollution Reduction Scheme (CPRS) on gas prices and other energy and water policy measures, as well as the economic impact of the global financial crisis.

Building block revenue proposal

ActewAGL Distribution's forecast capital and operating expenditures for the gas network over the access arrangement period are set out in Table 0.1 and in chapter 6 of this access arrangement information.

Table 0.1 Forecast capital and operating expenditures

$m (real 2009/10)	*20010/11*	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*Total*
Net capital expenditure*	24.7	73.5	93.1	10.4	11.0	214.7
Total operating expenditure	21.8	23.9	24.5	24.3	24.6	119.0

*Net of capital contributions, includes equity raising costs

Forecast **capital expenditure** for the access arrangement period, net of capital contributions, is $214.7 million. ActewAGL Distribution proposes a major capital project, the Hoskinstown Fyshwick Loop (HFL) to address continuing concerns over security of supply on the network. The HFL project ($134.3m across 2011/12 and 2012/13) accounts for well over half (63 per cent) of the total capital expenditure forecast for the access arrangement period.

Market expansion capital expenditure—undertaken to meet growth in customer numbers and connections—is forecast to total $35.1 million over the access arrangement period. This expenditure will be required to service land releases and construction during the period in the Molonglo District and North Weston in the ACT and Googong in NSW, and for infill in the medium density Canberra suburb of Swinger Hill.

The capital program for the access arrangement period also includes capacity development expenditure for continuing load growth on the network at a forecast cost of $21.6 million. The expenditure is driven largely by a small number of relatively large projects including:

- Construction of the Tuggeranong Primary Mains extension and Tuggeranong Primary Regulating Station in 2010/11 and 2011/12 to support capacity growth and security of supply in the Tuggeranong District;
- Installation of a permanent 50,000 m^3/hr trunk receiving station in Queanbeyan during 2010/11 as part of the progressive installation of capacity in the Queanbeyan area to meet demand in Queanbeyan, Jerrabomberra, Fyshwick, Hume, and the proposed new developments of Googong and Tralee; and
- Construction of the Griffith/Red Hill secondary mains extension in 2014/15 to provide capacity for growth and supply reliability to customers supplied from the South Canberra medium pressure network in the Canberra suburbs of Red Hill, Deakin, Griffith, Narrabundah and Forrest.

In addition to the proposed HFL security of supply project discussed above, stay in business capital expenditure—relating to the renewal and replacement of ageing network assets, asset condition, and compliance requirements for safety, reliability and asset protection—is forecast at a further $22.3 million. This expenditure includes upgrade of the Fyshwick Trunk Receiving Station, replacement of aged residential and Industrial and Commercial gas meters, installation of scraper stations on the Canberra Primary Main and pigging facilities on the Hoskinstown to Fyshwick Trunk Main.

Total forecast **operating and maintenance expenditure** for the access arrangement period is $119.0 million, 36.7 per cent higher (in real terms) than the outturn operating expenditure for the earlier access arrangement period. This increase is due mainly to step changes in costs arising from the requirements of enhanced technical standards, and required maintenance of ageing assets, together with additional maintenance on new and augmented facilities. These factors are detailed in chapter 9 of this access arrangement information.

In making comparisons with outturn operating costs in the earlier access arrangement period, it needs to be noted that forecast operating costs for the access arrangement period include a full five years of the ACT's Utilities Network Facilities Tax, self insurance costs, debt raising costs (both not previously included) and regulatory review costs (previously capitalised) not reflected in the earlier access arrangement period costs. These items account for around $11 million of apparently additional operating costs in the access arrangement period.

Despite the significant real reduction in operating and maintenance costs of 25 per cent over the 10 year period between 2001 and 2010, a further productivity factor of 0.5 per cent per annum is proposed to be applied to operating and maintenance fees paid to Jemena Asset Management Pty Ltd, ActewAGL Distribution's network management and services contractor.

The cost of ActewAGL corporate overheads is expected to increase by $4.7 million from the earlier access arrangement period. This increase is driven by higher operating costs beginning 2008 from the decision to lease, rather than own, ActewAGL's corporate headquarters, and higher information technology application costs.

ActewAGL Distribution has assumed no net increase in its corporate services employment over the access arrangement period. This treatment indirectly assumes an improvement in employee productivity, since the network is expected to grow substantially, the energy throughput to increase, customer numbers to grow by 15 per cent, and new obligations will be introduced, while the number of employees remains constant.

Other elements of the building blocks proposal include:

- A nominal vanilla weighted average cost of capital of 11.1 per cent based on current market parameters (derived as discussed in chapter 8 of this access arrangement information);
- A capital base rolled forward in accordance with the roll forward model in attachment S of this access arrangement information, yielding an opening capital value of $278 million;
- A tax asset base and depreciation schedules derived according to the AER's June 2007 issues paper *Transition of energy businesses from pre-tax to post-tax regulation* using standard tax lives for gas supply assets as per the relevant income tax: depreciation effective life ruling of the Tax Commissioner, as discussed in section 10.4 of this access arrangement information.

Revenue requirement

ActewAGL Distribution's proposed revenue requirement is shown in Table 0.2. The proposal involves indicative adjustments of CPI + 12.2 per cent in each year of the access arrangement period.

Table 0.2 Calculation of revenue requirement and X factors.

Nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Smoothed revenue requirement	55.36	63.13	72.78	84.33	97.42
of which tariff revenue	*52.59*	*60.06*	*69.23*	*80.23*	*93.22*
of which contract revenue	*2.77*	*3.07*	*3.55*	*4.10*	*4.20*
X factor tariff revenue (%)	12.21	12.21	12.21	12.21	12.21

ActewAGL Distribution's proposed gas network tariffs are incorporated in the access arrangement.

1 Introduction

1.1 Purpose of this document

This document addresses the requirement of Section 43(1) of the *National Gas Rules 2008*[1] that a service provider must submit, together with its access arrangement proposal, access arrangement information for the access arrangement proposal.

Rule 42(1) defines *access arrangement information for an access arrangement proposal* as:

> … information that is reasonably necessary for users and prospective users:
>
> (a) to understand the background to the access arrangement or access arrangement proposal; and
>
> (b) to understand the basis and derivation of the various elements of the access arrangement or access arrangement proposal.

This access arrangement information is provided by ActewAGL Distribution in respect of the revision of the access arrangement for its gas distribution network in the Australian Capital Territory (ACT), Queanbeyan and Palerang from 1 July 2010. The ActewAGL Distribution partnership performs this function on behalf of its owners ACTEW Distribution Ltd and Jemena Networks (ACT) Pty Ltd, the two service providers on the network. Their views with regard to the ACT, Queanbeyan and Palerang gas network are represented jointly and severally through the ActewAGL Distribution partnership.[2]

1.2 Requirements for access arrangement information

1.2.1 Rule requirements

Division 2 of Part 8 of the NGR deals with the requirements for access arrangement information. Immediately following the definition of access arrangement information in Rule 42(1) (quoted in section 1.1 above), Rule 42(2) in this division requires that “Access arrangement information must include the information specifically required by Law”. Rule 44 effectively makes clear that the access arrangement information forms part of the access arrangement and requires its publication and distribution with the relevant access arrangement.

Rule 43(2) allows the Australian Energy Regulator (AER) to permit a service provider submitting information for an access arrangement proposal to present sensitive information[3] in a form approved by the AER in which the information is aggregated or generalised to avoid disclosure or, if this is not possible, to be entirely suppressed.

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[1] Hereinafter, a reference to a Rule, Division or Part shall, unless otherwise specified, be understood to refer to a Rule, Division or Part as applicable of the *National Gas Rules 2008*.

[2] Further information on the service providers and this arrangement is provided at section 2.1 of this access arrangement information.

[3] *Sensitive information* is defined by Rule 43(2) as information that is confidential and its public disclosure could cause undue harm to the legitimate business interests of the service provider, a user or prospective user.

Information relating to this access arrangement information that is commercial-in-confidence or otherwise sensitive resides in the confidential attachments to this document and is summarised in the text.

Requirements for full access arrangements and relevant proposals are set out mostly in Rule 48 and elsewhere in the rules as summarised in Table 1.1.[4]

Related access arrangement information is to be provided insofar as it is required to allow users and prospective users "to understand the basis and derivation of the various elements of the access arrangement or access arrangement proposal".[5] The provisions relevant to the access arrangement information are listed in Table 1.1.

Division 2 of Part 9 of the NGR—*Price and revenue regulation* specifies *Access arrangement information relevant to price and revenue regulation*. Rule 72(1) in this division specifies the information required for a full access arrangement proposal, including, at Rule 72(1)(a), historic information required if, as is the case for the ACT, Queanbeyan and Palerang gas distribution access arrangement, the access arrangement period commences at the end of an earlier access arrangement period.[6] Rules 73 to 75 incorporate more general requirements for the access arrangement information. These requirements and the corresponding references within this access arrangement information are summarised in Table 1.2.

1.2.2 AER access arrangement guideline

The AER released its *Access arrangement guideline* (AA Guideline) on 25 March 2009. The AA Guideline is designed in part to "assist service providers in the preparation of access arrangement proposals"[7] and provides guidance in terms of both the AER's interpretation of the information required in submitting an access arrangement and the requirements for supporting information that the AER will consider in exercising its discretion to accept or reject elements of the access arrangement proposal.

The AA Guideline provides a checklist of components for an access arrangement submission.

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[4] These requirements apply also to an access arrangement proposal via the operation of Rule 48(2).
[5] NGR, section 42(1)(ii)
[6] This access arrangement information uses the convention established in the NGR of referring to the *access arrangement period*, being for ActewAGL Distribution the period 2010/11 to 2014/15, and the *earlier access arrangement period*, being the period 2004/05 to 2009/10.
[7] AER 2009, *Access arrangement guideline*, March, p 4

Table 1.1 Requirements for a full access arrangement

Rule	Rule requirement	AA proposal reference	AAI reference
48(1)(a)	Identity of the pipeline to which the access arrangement relates and a reference to a website at which a description of the pipeline can be inspected.	Part 1	Section 2.3
48(1)(b)	Description of the pipeline services the service provider proposes to offer to provide by means of the pipeline	Part 1	Section 11.1
48(1)(c)	Specification of the reference services	Part 2	Section 11.1
48(1)(d)(i)	The reference tariff for each reference service.	Part 5	
48(1)(d)(ii)	The other terms and conditions on which each reference service will be provided	Part 3	Section 12.3
48(1)(e)	Queuing requirements	Part 9	Section 12.9
48(1)(f)	Capacity trading requirements	Part 8	Section 12.8
48(1)(g)	Extension and expansion requirements	Part 7	Section 12.7
48(1)(h)	Changing receipt and delivery points	Part 3	Section 12.3
48(1)(i)&(j)	Review and expiry dates (if relevant)	Part 1	
51	Trigger events (if relevant)		
84	Speculative capital expenditure and investment policy	Part 4	Section 6.2.3.4
85	Capital redundancy policy	Part 4	Section 7.2.7
85(3)	Policies for other mechanisms (cost sharing if demand falls)		
90(2)	Whether depreciation for the opening capital base is based on actual or forecast depreciation	Part 6	Section 7.2.3.3

Table 1.2 Requirements for access arrangement information relevant to price and revenue regulation

Rule	Rule requirement	AAI Reference
72(1)(a)(i)	**Capital expenditure** by asset class over the earlier access arrangement period	Section 6.1.5
72(1)(a)(ii)	**Operating expenditure** by category over the earlier access arrangement period	Section 9.1
72(1)(a)(iii)	**Usage of the pipeline over the earlier access arrangement period**, including (A) **minimum and maximum demand** with their seasonal variations and (B) **customer numbers** in total and by tariff class	Section 5.1
72(1)(b)	**Derivation of the capital base** and a demonstration of the increase or diminution over the previous access arrangement period	Section 7.1
72(1)(c)(i)	The **projected capital base** over the access arrangement period including a forecast of **conforming capital expenditure** for the period and the basis for the forecast	Section 6.2
72(1)(c)(ii)	The **projected capital base** over the access arrangement period including a forecast of **depreciation** for the period including a demonstration of how the forecast is derived on the basis of the proposed depreciation method	Section 7.2.3
72(1)(d)	The **capacity of the pipeline** and, where practicable, the justified **projected utilisation** of pipeline capacity over the access arrangement period	Section 5.2
72(1)(e)	A justified **forecast of operating expenditure** over the access arrangement period	Section 9.2
72(1)(f)	**Key performance indicators** used to justify expenditure incurred over the access arrangement period	Section 13
72(1)(g)	The **proposed rate of return**, the assumptions on which it was calculated and a demonstration of how it was calculated	Section 8.1
72(1)(h)	The proposed **method of dealing with taxation**, and a demonstration of how the **taxation allowance** is calculated	Section 10.4
72(1)(i)	The proposed carry-over of **increments from any incentive mechanism** that operated in the previous period	Section 10.6.1
72(1)(j)	The **proposed approach to price-setting** including (i) the suggested **basis of reference tariffs** (including the method used to allocate costs and a demonstration of the relationship between costs and prices) and (ii) a description of any **pricing principles employed** but not otherwise disclosed under this rule.	Section 11
72(1)(k)	The service provider's justification for any **proposed reference tariff variation mechanism**	Section 11
72(1)(l)	The service provider's justification for any **proposed incentive mechanism**	Section 10.6.2
72(1)(m)	The **total revenue** to be derived from pipeline services for each regulatory year of the access arrangement period	Section 9.5
73	All financial information must be supplied in a stated consistent and recognised **basis for dealing with inflation** and that the basis on which financial information is provided must be stated	Section 1.3

1.2.3 Information required by Regulatory Information Notice

On 11 May 2009, the AER served on ActewAGL Distribution (as the partnership of the two service providers of the ActewAGL ACT, Queanbeyan and Palerang gas distribution network) a Regulatory Information Notice (RIN) under Division 4 of Part 1 of Chapter 2 of the National Gas Law (NGL). The RIN specifies the form of information to be provided to the AER and, where such information is to be provided by ActewAGL Distribution as part of its access arrangement proposal, that the access arrangement information include an index specifying its location. The RIN states that:

> As the AER is not mandating the form and manner of all information that is required to be provided in this Notice (including that it be provided in the pro formas) to demonstrate compliance with this Notice the service provider must provide an index or

list of where the information and documentation required to be provided in the Notice is included in the access arrangement proposal submission.[8]

Attachment B to this access arrangement information includes a list at Table B.1 specifying the location of information required by the RIN within this access arrangement information and the access arrangement proposal.

In most cases, the RIN restates the information required by the NGL and NGR. In a few cases, the information sought under the RIN is not relevant to the circumstances of ActewAGL Distribution. The latter position was anticipated by the AER in the RIN where it states:

> In some cases the information and documentation requested may not be relevant to the access arrangement proposal … Where this may be the case, … the service provider must provide a statement in the access arrangement proposal submission that this information and documentation are not relevant to the service provider's access arrangement revisions proposal and outline why the information and documentation is not relevant. However, the service provider's ability to do this is subject to the requirements under the Law and Rules, and where there is a conflict, the requirements under the Law and Rules prevail.[9]

In accordance with this requirement, ActewAGL Distribution has clearly indicated in the access arrangement information where it has not provided information outlined in the RIN that it considers is not relevant to its access arrangement.

1.3 Basis of information in the access arrangement proposal

Rule 73 states that:

(1) Financial information must be provided on:

  (a) a nominal basis; or

  (b) a real basis; or

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

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

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

Unless otherwise stated, financial information in this access arrangement information is provided in 2009/10 real dollars. Past values are brought to this basis using the Consumer Price Index (CPI) all groups, eight capital cities average June over June published by the Australian Bureau of Statistics (ABS) and the Reserve Bank of Australia's (RBA's) forecast for the individual years 2008/09 and 2009/10. Estimated inflation for the access arrangement period for the financial modelling is forecast as discussed in section 8.2 of this access arrangement information.

[8] AER RIN, p 22
[9] AER RIN p 23

Despite the commencement date of the earlier access arrangement being 1 January 2005 (as the result of the granting of a six month extension on submission), financial modelling for the earlier access arrangement period treated the financial year 2004/05 as a complete year. For modelling purposes, 2004/05 is included in the earlier access arrangement period so as to be consistent with the previous final decision and financial models.

Units used in this document are noted throughout and described in the abbreviation list at attachment A to this access arrangement information.

1.4 Layout of the access arrangement information

Subsequent chapters of this access arrangement information incorporate detailed information on the basis and derivation of the elements of the access arrangement required by the NGR, set out as follows:

- Chapter 2 contains general and summary information on ActewAGL Distribution’s access arrangement and access arrangement revision proposal;
- Chapter 3 provides an overview of ActewAGL Distribution’s long-term network strategy, network planning and governance processes, and key planning systems, processes, models and documents;
- Chapter 4 provides an overview of current and new and changing regulatory obligations that apply to ActewAGL Distribution, as well as relevant service performance for the gas network and service standard targets;
- Chapter 5 discusses network demand and utilisation during the earlier access arrangement period and forecast demand over the access arrangement period;
- Chapter 6 explains the process of assessment for capital expenditure, capital expenditure undertaken and to be undertaken during the earlier access arrangement period and the justification and forecast cost of capital projects during the access arrangement period;
- Chapter 7 outlines the derivation of the opening capital base of the ActewAGL Distribution gas network from which a return on and of capital are calculated;
- Chapter 8 explains the parameters of the capital asset pricing model proposed for calculation of the weighted average cost of capital for the rate of return during the access arrangement period and derivation of the forecast rate of inflation required by the post tax revenue model;
- Chapter 9 explains the derivation of operating and maintenance costs and the basis of other non-capital costs including taxation, self insurance and greenhouse gas emissions trading costs;
- Chapter 10 calculates the total revenue to be derived from the network, including cost of service and the impact of other factors such as incentive mechanisms for efficiency;
- Chapter 11 specifies the services offered and explains the basis and derivation of tariffs, including cost allocation, customer classes and tariff variation mechanisms;

- Chapter 12 summarises proposed revisions to the access arrangement;
- Chapter 13 addresses the requirement to include Key Performance Indicators in the access arrangement information; and
- Attachments contain explanatory and supporting material required by the RIN or referred to in the text.

2 General and summary information

This chapter of the access arrangement information contains general and summary information on ActewAGL Distribution's access arrangement and access arrangement revision proposal.

It includes an overview of the operations of ActewAGL Distribution and the market context for the network.

2.1 Overview of the operations of the service provider

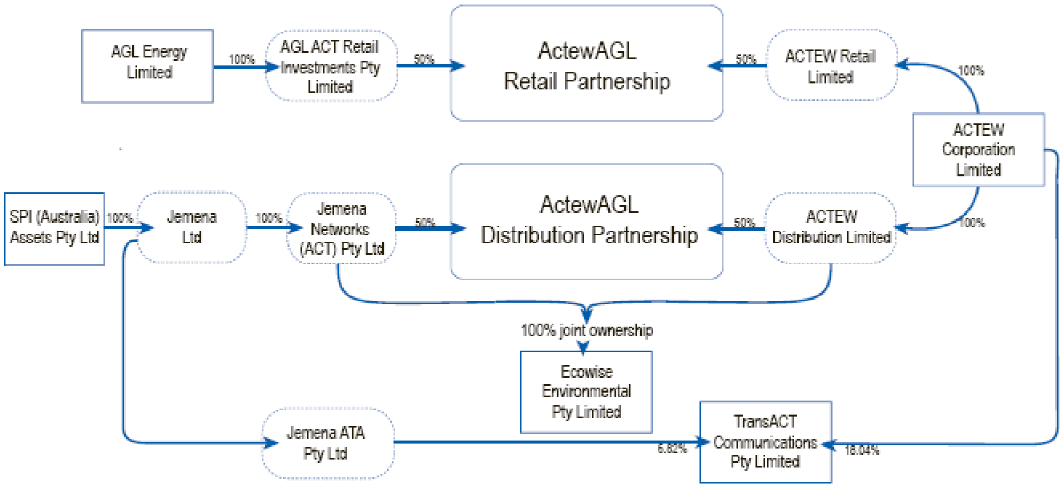
ActewAGL is Australia's only genuine multi-utility service provider. Formed in October 2000 as the result of a unique public–private joint venture between the ACT Government owned ACTEW Corporation Limited (ACTEW) and the Australian Gas Light Company (AGL), ActewAGL is based in Canberra and operates across the ACT and the *Capital Region* of southern New South Wales (NSW). ActewAGL's core business is the distribution and retailing of energy and the management of water and wastewater services. ActewAGL's ancillary services include the retailing of telecommunications products.

The ActewAGL joint venture comprises two partnerships—ActewAGL Distribution and ActewAGL Retail. As a result of business arrangements in October 2006 between AGL and Alinta Limited (Alinta), ActewAGL Distribution became a partnership of ACTEW and Alinta through wholly owned holding company subsidiaries.[10] The ActewAGL Retail partners are ACTEW and AGL Energy Ltd. Alinta subsequently became wholly owned by Singapore Power International and, in August 2008, was renamed Jemena Limited. A representation of the ownership structure of the ActewAGL joint venture partnerships forms Figure 2.1.

ActewAGL Distribution is licensed under the *Utilities Act 2000* (ACT) to provide gas distribution and connection services in the ACT, and holds a Reticulator's Authorisation under the *Gas Supply Act 1996* (NSW) for its gas distribution system in the Queanbeyan City Local Government Area (LGA) and in the adjoining Palerang LGA, and a pipeline licence for the Eastern Gas Pipeline (EGP) interconnect from Hoskinstown in NSW to the ACT border.

[10] ActewAGL Distribution qualifies as a *legal entity* under the *National Gas Law* (section 131(e)) by being a person qualified by s.131(a)—a legal entity registered under the *Corporations Act 2001* (Cth)—providing a covered pipeline service together with another such person.

Figure 2.1 Ownership structure of the ActewAGL joint venture partnerships



The NGL defines a service provider as a person who owns, controls or operates a pipeline or intends to own, control or operate a pipeline. In respect of the ACT, Queanbeyan and Palerang gas distribution network, the parties that satisfy the definition under the NGL are:

- ACTEW Distribution Limited (ACN 073 025 224): and
- Jemena Networks (ACT) Pty Ltd (ACN 008 552 663).

The two service providers, (the ActewAGL Distribution *partner companies*), jointly own, control and operate the network. The partner companies act through the ActewAGL Distribution partnership in which they hold equal shares.

The ActewAGL Distribution partnership meets the regulatory and other obligations that rest at law upon the partner companies given that the latter are formal legal entities and a partnership in the ACT is not a legal entity.

The NGL also includes provisions relating to a “service provider acting on behalf of other service providers” and a “local agent of a service provider”.

ActewAGL Distribution 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.

2.2 Coverage and regulatory background of the network

2.2.1 Regulatory history

In 1998, the relevant Commonwealth minister certified the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Gas Code) as an effective access regime for the state of South Australia (SA) under section 44N of the *Trade Practices Act 1974* (Cth), effective for 15 years. The Gas Code was made law in SA under the *Gas Pipeline Access (South Australia) Act 1997* (SA) and formed schedule 2 to that Act.

The Gas Code was given application in the ACT under the *Gas Pipeline Access Act 1998* (ACT) and was separately certified for the ACT by the relevant Commonwealth minister on 25 September 2000 (effective for 15 years).

In January 2001, the ACT regulator, the Independent Competition and Regulatory Commission (ICRC), approved ActewAGL Distribution's Access Arrangement for the natural gas system in ACT, Queanbeyan and Yarrowlumla, which came into effect on 1 February 2001.[11] Under that access arrangement, ActewAGL Distribution was required to submit proposed revisions to the access arrangement by 30 June 2003. It was envisaged that the revisions to the access arrangement would commence on 1 July 2004. Closer to this revision date, ActewAGL sought from the ICRC, and was granted, an extension of six months to the revisions submission date because of the uncertainty that would have otherwise been the result of changes pending to the Gas Code.

In December 2003, ActewAGL Distribution submitted to the ICRC proposed revisions to the 2001 access arrangement. These proposed revisions outlined access terms and conditions, tariffs and services, extensions, expansions, trading, queuing, capacity management and tariff policies on which third parties may access ActewAGL's gas distribution network in the ACT and Greater Queanbeyan.

The final decision required ActewAGL Distribution to make a number of amendments to the revised access arrangement and access arrangement information before the ICRC would approve the proposed revisions. ActewAGL submitted its revised access arrangement and access arrangement information incorporating these amendments on 3 November 2004. The ICRC's *further final decision*, issued under section 2.41 of the Gas Code, was published in November 2004 providing final approval of ActewAGL Distribution's revised access arrangement.

2.2.2 Transition to the National Gas Law

With the commencement of the National Gas Law on 1 July 2008, the AER assumed the role of economic regulator for covered (that is, regulated) distribution pipelines in all states (except Western Australia) and the ACT. This was in addition to its earlier role of regulating covered gas transmission pipelines in all states except Western Australia. The NGL has been enacted in these jurisdictions via mirror legislation.[12] The NGR forms a schedule to the legislation and has the force of law.[13]

Distribution and transmission pipelines covered under the former Gas Code immediately before the commencement of the NGL are deemed to be covered pipelines under the

[11] Economic regulation of the NSW portions of the gas distribution network in Queanbeyan and Yarrowlumla was cross-vested to the ACT regulator.
[12] Under the *National Gas (ACT) Act 2008* (ACT) section 8, the National Gas Law set out in the schedule to the *National Gas (South Australia) Act 2008 (SA)* applies as a law of the ACT and as so applying may be referred to as the *National Gas (ACT) Law.*
[13] NGL, section 26

NGL.[14] The NGL also specifies that current access arrangements, approved or drafted and approved by a relevant regulator under the Gas Code, are deemed to be full access arrangements approved or made by the AER under the NGL.[15]

The NGL requires a covered pipeline service provider to submit to the AER, for its approval under the Rules, a full access arrangement or revisions to an applicable full access arrangement in respect of the services that the service provider intends to provide.[16] It also requires that the AER exercise its economic regulatory functions and powers in a manner that will or is likely to contribute to the achievement of the national gas objective.[17] This objective 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.[18]

The provisions at Schedule 3 of the NGL and Schedule 1 of the Rules apply to the ActewAGL Distribution gas network since the earlier access arrangement falls under these provisions within the definition of a *transitional access arrangement*.

General savings provisions of the NGL state that the repeal of the Code does not affect "the previous operation of the old access law or Gas Code or anything suffered, done or begun under or in accordance with the old access law or Code".[19]

Under the *Transitional provisions* of the NGL, sections 3, 8 and 10.8 of the Code "continue to apply to a transitioned access arrangement" until revisions to that access arrangement take effect.[20]

Transitional provision 3(9) of the NGR specifies that a date designated in a transitional access arrangement as a *revisions submission date* will be taken to be a review submission date for the purposes of the NGR. Similarly, a revisions commencement date in a transitional access arrangement will be a commencement date under the NGR. The review submission date for ActewAGL Distribution's earlier access arrangement is 30 June 2009.[21] According to Rule 52(1), a service provider must submit to the AER for approval an access arrangement revision proposal on or before the review submission date of an applicable access arrangement.

2.3 Network history and characteristics

Natural gas first became available in the ACT in 1982 and since then the gas network has progressively expanded. AGL provided gas distribution and retail services in the Canberra

[14] NGL, schedule 3, sections 6 and 7
[15] NGL, schedule 3, section 26
[16] NGL, section 132
[17] NGL, section 28
[18] NGL, section 23
[19] NGL, Schedule 3, section 3
[20] NGL, Schedule 3, section 30. Section 3 of the Gas Code related to the content of an access arrangement, Section 8 governs reference tariff principles; and Section 10.8 contains definitions.
[21] ActewAGL Distribution 2004, *Access Arrangement for ActewAGL Gas Distribution System in ACT and Greater Queanbeyan*, November, clause 1.15

region before forming the joint venture with ACTEW to create ActewAGL as a combined retailer and distributor of electricity and gas in October 2000.[22] Jemena Networks (ACT) Pty Ltd (via its predecessor Alinta) became the ActewAGL Distribution partner with ACTEW Distribution Ltd in October 2006.

The ACT retail gas market was opened to competition in January 2002. As a result, customers may now choose their gas supplier. Before contestability was introduced, ActewAGL Retail supplied gas to all consumers within the access arrangement area. There are currently eight licensed gas suppliers servicing the market.

Recent geographic information system (GIS) data from the ACT Planning and Land Authority (ACTPLA) reveal that there are 120,481 blocks in ACT designated as *residential.*[23] Of these, 118,727 (or 98.5 per cent) are located within 30 metres of a gas main. As at 31 December 2008, ActewAGL Distribution's has nearly 112,000 customer sites in the ACT and NSW.

Figure 2.2 is a map showing transmission pipelines, primary pipelines and gas coverage areas of the ActewAGL Distribution ACT, Queanbeyan and Palerang gas distribution network in the ACT and Queanbeyan.

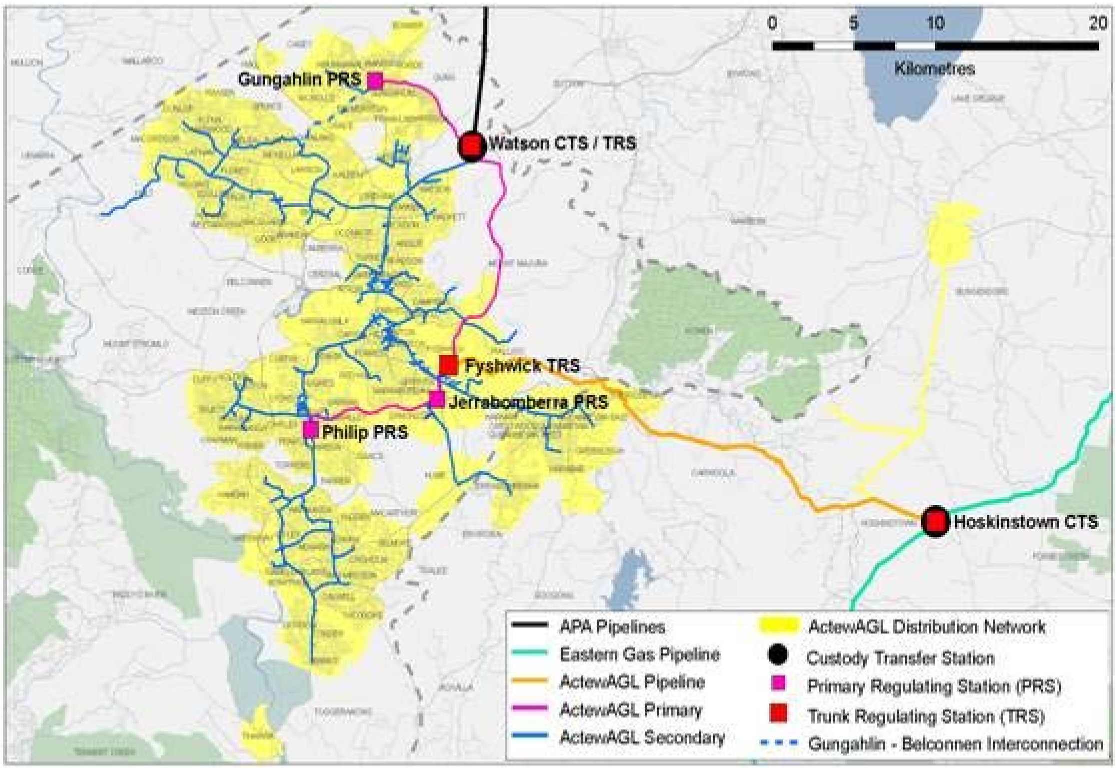
Natural gas is supplied to the ActewAGL Distribution network via high pressure transmission pipelines from two sources:

- from the north of Canberra, the APA Group owned Dalton to Watson Lateral transmission pipeline which branches off the Moomba–Sydney Pipeline (MSP) which in turn transports natural gas from the Cooper Basin in South Australia across NSW to Sydney; and
- from the east of Canberra, the ActewAGL Hoskinstown to Fyshwick trunk main which interconnects at Hoskinstown with the EGP which transports natural gas from Longford in Victoria through NSW to Sydney.

Gas is delivered to the primary network from the Watson Custody Transfer Station (CTS) and Fyshwick Trunk Receiving Station (TRS) (on the Hoskinstown to Fyshwick trunk main). The primary network supplies the secondary network through four Primary Regulator Sets (PRSs) located at Watson, Phillip, Gungahlin and Narrabundah (Jerrabomberra PRS). The secondary network which operates at 1,050 to 525 kPa subsequently supplies the medium pressure networks via Secondary District Regulator Sets (SDRSs) which reduce the pressure to 210 kPa. Domestic and most industrial and commercial (I&C) customers are connected to the medium pressure system. Large I&C customers requiring greater volumes of gas are connected to the higher pressure mains.

[22] ACTEW Corporation retains ownership of the ACT's water and wastewater assets which are managed and operated under contract by the ActewAGL Distribution partnership.
[23] The residential total includes suburban, suburban core, urban residential, med/high density residential and mixed use land use classifications

Figure 2.2 Transmission pipelines, primary pipelines and gas coverage areas of the ACT, Queanbeyan and Palerang



During the earlier access arrangement period, ActewAGL Distribution commenced reticulating natural gas to more than 570 customers in the town of Bungendore via an extension of the network of approximately 48 km of medium pressure mains. The network is fed from the EGP, with custody transfer occurring before delivery to Bungendore Packaged Offtake Station (POTS) located in the Hoskinstown TRS compound. The Bungendore POTS reduces the pressure of the gas from 14,900 kPa to 400 kPa. The outlet main of the POTS runs approximately 20 km and supplies gas to the medium pressure network in Bungendore.

The geographical designation in the title of the access arrangement is proposed to change from “ACT and Greater Queanbeyan” to “ACT, Queanbeyan and Palerang” to reflect changes to NSW local government boundaries and names as well as extension of the network to Bungendore, now in the Palerang Council area, during the earlier access arrangement period.[24] The Bungendore network is a covered network under this access arrangement through the operation of the extensions and expansions policy applying in the earlier access arrangement period.

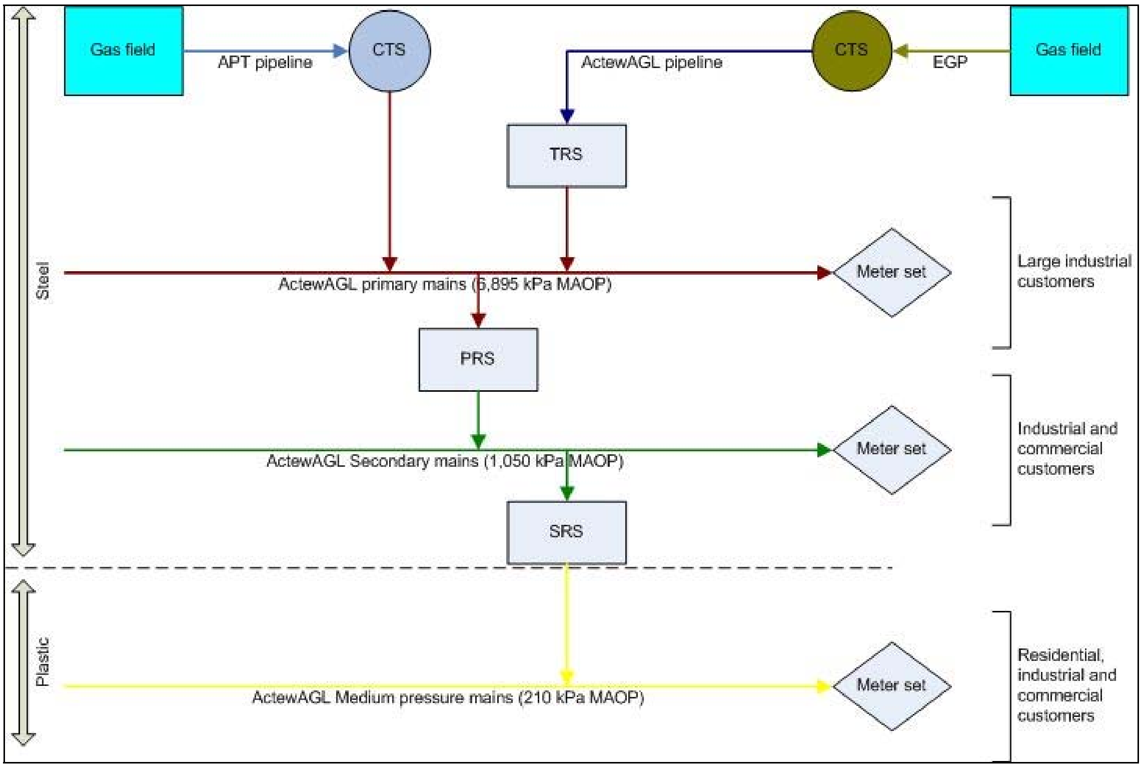
[24] Before 2004, the access arrangement referred to Queanbeyan and Yarrowlumla, the latter a reference to the former Yarrowlumla Shire LGA which previously surrounded the ACT and Queanbeyan City Council areas. Yarrowlumla Shire was abolished in February 2004 with parts being absorbed into to the Queanbeyan City LGA, (which became Greater Queanbeyan City Council) and some of the remainder into the former Tallaganda Shire LGA, forming a new Palerang LGA. The Greater Queanbeyan LGA subsequently reverted to the name Queanbeyan City Council. The Palerang LGA includes the village of Bungendore to which the network was extended during the earlier access arrangement period.

ActewAGL's gas distribution network consists in total of approximately 4,160 km of mains in total.

In 2007/08, the *Residential tariff* sector made up 97 per cent of customers and accounted for 65 per cent of total gas sales. *Business tariff* customers made up a further 2.6 per cent of customers and 21 per cent of total gas sales. The remaining 14 per cent of gas sales was attributable to 38 contract customers.

Figure 2.3 is a schematic of the network configuration. Details of the ActewAGL gas network can also be found at the ActewAGL website. Table 2.1 provides a summary of network assets and statistics.

Figure 2.3 Schematic of the network configuration



APT=Australian Pipeline Trust; EGP= Eastern Gas Pipeline; CTS=custody transfer station; TRS=trunk receiving station; PRS=primary regulating station; SRS=secondary regulator set

Table 2.1 Characteristics of ActewAGL gas network assets

Asset class	Volume (km or number)	Description
Transmission mains	30.3 km	The single asset in this class, the Hoskinstown–Fyshwick pipeline, was built in 2000/01 to supply gas to the primary network via the Fyshwick TRS. This asset class comprises pipelines, cathodic protection systems and easements. The pipeline has a diameter of 250 mm and a maximum allowable operating pressure (MAOP) of 14 900 kPa.
Primary mains	37.9 km	Primary mains provide natural gas to the secondary distribution systems of the ACT and Queanbeyan. They are constructed of high strength steel pipe of 250 mm diameter and have an effective MAOP of 6,895 kPa. They are internally and externally protected against corrosion by a physical coating and via cathodic protection.
Secondary mains	209 km	Secondary mains provide gas to the District Regulator Sets within the ACT and Queanbeyan networks. They also directly supply a number of large contract customers. The secondary mains network is constructed from steel pipe externally coated to protect against corrosion. Mitigation of corrosion risk is also achieved via cathodic protection. Secondary mains have an MAOP of 1,050 kPa.
Medium pressure mains	3,771 km	Medium pressure mains supply natural gas to domestic and I&C users. They are predominately plastic (polyethylene and nylon) and operate at an MAOP of 210 kPa.
Trunk receiving and custody transfer stations	1	The trunk receiving station at Watson provides the step down from transmission pressure in the Dalton–Watson lateral pipeline to the lower network pressures.
Trunk receiving stations	1	The trunk receiving station at Fyshwick provides the step down from transmission pressure in ActewAGL's Hoskinstown–Fyshwick pipeline to the lower network pressures.
Primary regulating stations	4	Primary regulating stations are pressure reduction facilities located at each off-take on the primary main. The ACT/Queanbeyan PRSs reduce pressure from an MAOP of 6,895 kPa to supply the secondary network at 1,050 kPa.
Package offtake stations	1	Bungendore POTS is located in the Hoskinstown TRS compound. The Bungendore POTS reduces the pressure of the gas from 14,900 kPa to 400 kPa.
Secondary district regulator sets	87	Secondary district regulator sets are required at each off-take from the secondary system to supply medium pressure systems. They reduce the pressure from 1,050 kPa inlet to 210 kPa outlet pressures.
Residential meter sets	107,565	ActewAGL Distribution provides energy transportation services for energy retailers and their customers. The financial transactions between the networks, energy retailers and the end users are largely determined by the metering equipment provided by ActewAGL Distribution to measure delivered quantities.
Industrial and commercial (I&C) meter sets	3,190	I&C meter sets have the same purpose and functionality as residential meter sets. However, equipment complexity, unit cost and maintenance requirements increase with load size and as the network delivery pressures increase.

Source: Asset Management Plan, table 1.1.

Some particular characteristics of the ActewAGL gas network are that:

- it is a relatively modern network;
- it utilises a *dual mains* configuration (that is, mains on both sides of streets);[25]
- it is a predominately residential customer based network with a low number of industrial customers and load—the load is approximately 14 per cent industrial

[25] See explanation of the dual mains configuration at attachment E of this access arrangement information.

compared to that of, for example, Jemena's Sydney gas network which is approximately 65 per cent industrial;

- because of climatic conditions, average residential gas consumption is relatively high, with extreme morning and evening peaks; and
- network size is comparatively small with a relatively low customer density.

Relevant comparisons with other gas distribution networks are provided at attachments E and F to this access arrangement information.

2.4 Current market issues

ActewAGL distribution identifies several issues affecting natural gas demand and supply relevant to this access arrangement proposal. These include:

- the impact of the global financial crisis;
- implementation of the Australian Government's carbon pollution reduction measures and related federal and jurisdictional initiatives;
- security of supply concerns;
- expected impacts of the proposed short term trading market for gas; and
- introduction of new laws and rules governing the relationships between network operators, retailers and end use customers.

These are discussed in the following sections.

2.4.1 The global financial crisis

The unprecedented global financial crisis, which commenced in the second half of 2008, and the domestic slowdown it spurred are expected to impact the access arrangement at several levels.

A significant decline in commodity prices during 2008, including those for steel and aluminium, is reflected in the capital escalators that ActewAGL Distribution is using in the access arrangement. At the time of submitting the access arrangement proposal, several financial indicators suggest that a recovery could be underway, or at least beginning. Oil prices, for example, have started to increase along with those of some other commodities.

Since February 2009, the yield on the Commonwealth Government Securities has increased by approximately 1 percentage point and turbulence on stock exchanges has reduced somewhat. However markets remain volatile, with the result that investors require higher returns. In other words, there is significant evidence indicating that the market risk premium has increased.

The global financial crisis is expected also to affect the growth in energy throughput in the ACT as economic activity has declined, but is expected to pick up by the end of the access arrangement period. These effects are reflected in the demand forecasts in chapter 5 of this access arrangement information.

It will be important for the AER to acknowledge the changing market circumstances in determining ActewAGL Distribution's efficient costs for the access arrangement period.

2.4.2 Challenges of climate change and carbon pollution reduction

ActewAGL Distribution, along with many other gas distribution network service providers, is expected to become responsible for mandatory reporting under the National Greenhouse Emissions Reporting Scheme (NGERS) and the purchase of permits to cover its liabilities under the *cap and trade* regime at the centre of the Carbon Pollution Reduction Scheme (CPRS) to be introduced by 2011.

The CPRS is also expected to influence the costs of input materials for building and managing the ActewAGL Distribution gas network, as the cost of carbon is reflected in the price for various goods and services. The CPRS will also affect demand for gas through price impacts and the perception of natural gas as an environmentally friendly fuel of choice.

These aspects are reflected in forecast costs and demand where possible. Direct costs associated with the CPRS also need to be managed through regulatory mechanisms.

2.4.3 Security of supply concerns

ActewAGL Distribution proposes a major capital project, the Hoskinstown Fyshwick Loop (HFL) to address continuing concerns over security of supply on the network. HFL involves a 21 km looping of the Hoskinstown to Fyshwick trunk main to create storage capacity to overcome supply shortages during the winter peak period.

The need for a security of supply project has been demonstrated over successive winters where upstream facilities have failed or insufficient gas has been nominated by retailers. The dominance of the tariff market (accounting for approximately 86 per cent of gas volumes on ActewAGL Distribution's network) means that there are no significant loads that can be readily shed. This is in contrast to other networks, where curtailing selected commercial and/or industrial customers can result in a much more significant reduction in demand that is more likely to be sufficient to maintain security of supply in the event of a supply disruption.

Such a disruption represents a significant risk to human health and safety due to the reliance on gas for space heating in the ACT, and the time it would take to restore supply after a significant event. A significant disruption would be extremely costly for ActewAGL Distribution, and to users, as the process of disconnection and reconnection requires significant labour resources. Restoration of supply after a major disruption would also take months.

Following the most recent upstream supply events in 2008, the ACT Chief Minister wrote to ActewAGL requesting that it examine, as a matter of high priority, what is in its power to do to provide greater security of gas supply to the ACT and the region. Of the infrastructure and market options examined, HFL is identified as the best option to deal with the security of supply issue facing the network with regard to lead time and being within the control of ActewAGL Distribution.

2.4.4 Roll out of the short term trading market

The establishment of the Short Term Trading Market (STTM) for gas, beginning with the establishment of market hubs for Sydney and Adelaide in 2010, is expected to affect gas market security of supply in the ACT. Increased trading of gas between the MSP and EGP as a result of the STTM is expected to make network management, in particular the management of pressure at the Watson and Hoskinstown receipt points, more difficult, as well as increasing the cost of balancing gas at times of supply shortage.

There is still some uncertainty over the final form of the STTM, which is to be finalised after lodgement of the access arrangement proposal. There is also potential for a trading hub to be established in Canberra at some time during the access arrangement period.

ActewAGL Distribution considers that, given the uncertainty over the final form of the STTM and its application in the ACT, regulatory mechanisms are warranted to deal with this risk.

2.4.5 New national energy customer and connections arrangements

The Ministerial Council on Energy (MCE) is currently developing new arrangements for the transfer of non-economic electricity and gas distribution and retail functions to a national framework. Of relevance to gas, these arrangements will support new consumer protection arrangements, changed service definitions, new national customer/retailer/distributor contracting arrangements, and a new gas connection framework, including capital contributions.

The MCE released a first exposure draft of legislation and rules covering the new National Energy Customer Framework (NECF) in April 2009. A second exposure draft of the legislation, currently slated for release in late 2009, is expected to include a broader scope, picking up further gas-related policy decisions in relation to connections, retailer of last resort and transitional arrangements for the entire legislative package. The finalised legislative package is expected to be introduced into the parliaments in 2010.

It is expected that there will be significant transitional issues associated with the move to national arrangements, as they will impact on current customer contracts, and business and compliance structures. A timetable for passage of this legislation, including transitional arrangements and details of when provisions will come into effect, has not been released.

While ActewAGL recognises that some obligations are likely to change in the future as a result of the NECF, it is very difficult to predict the nature, extent and timing of the changes, and their possible implications for the access arrangement period. ActewAGL Distribution has therefore prepared its access arrangement on the basis of current arrangements. ActewAGL Distribution considers that, given the uncertainty over the final form of the NECF and its application in the ACT, regulatory mechanisms are warranted to deal with the risk that the new framework will come into effect during the access arrangement period.

2.4.6 Marketing and expansions

Until 2007, ActewAGL Distribution's marketing strategy to expand the gas market was based primarily on retailer incentives to fund the promotion of natural gas. An assessment of this strategy in 2007 found reduced effectiveness of the approach, and a new strategy was developed and implemented in 2008. The new marketing strategy involves direct network management and control of marketing expenditure and targeting of incentive payments to key appliance influencers such as gas appliance installers as well as gas retailers.

ActewAGL Distribution’s gas marketing proposal is discussed in section 9.2.2.4 of this access arrangement information. As discussed under forecast demand in section 5.2 of this access arrangement information, ActewAGL Distribution expects that its proposed marketing program will increase the baseline residential demand forecast by independent forecaster, the National Institute of Economic and Industry Research, by 18 TJ per annum cumulatively over the access arrangement period.

3 Network planning and asset management

This chapter of the access arrangement information provides an overview of ActewAGL Distribution's long-term network strategy, network planning and governance processes, and key planning systems, processes, models and documents.

The information in this chapter supports ActewAGL Distribution's capital and operating expenditure forecasts outlined in chapters 6 and 9 of this access arrangement information by providing a description of the planning and governance processes undertaken by ActewAGL Distribution in respect of network strategy, and subsequent capital and operating expenditure decisions. The processes described in this chapter provide the framework for ensuring that expenditure decisions made by ActewAGL Distribution are efficient and prudent.

This information is relevant to requirements under the Rules to demonstrate that capital and 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 providing services".[26]

ActewAGL Distribution's long-term network strategy and direction are discussed in section 3.1. This strategy is a key driver of the overall approach to network planning and asset management for the ActewAGL Distribution gas network, to address regulatory and market outcomes and deliver outcomes that customers want. ActewAGL Distribution's network strategy includes outsourcing asset management functions to an external provider. Jemena Asset Management Pty Ltd (JAM) provides asset management services to ActewAGL Distribution under contract. Section 3.1.1 discusses the nature of this contract and the roles of ActewAGL Distribution and JAM in respect of network planning and asset management.

Section 3.2 discusses the processes and methodologies used to develop forecasts for key network planning components: capacity development, market expansion and stay in business expenditure. Section 3.3 provides an overview of ActewAGL Distribution's annual planning cycle, and key network plans are discussed in section 3.4. Sections 3.5 and 3.6 then discuss respectively the expenditure governance process in place between ActewAGL Distribution and JAM, and capital expenditure deliverability.

3.1 Network strategy and direction

ActewAGL Distribution's gas network since the early 1980s has been developed to meet the following overarching business philosophy:

> To provide the local community and businesses with the choice of an alternative energy source via the delivery of a safe and reliable supply of natural gas.

[26] NGR 79(1). ActewAGL notes that NGR 91(1) relating to operating expenditure has slightly different wording, though these differences are not relevant to the discussion in this chapter.

With this objective in mind, the development of the network has evolved over the past three decades to meet the changing nature of both customer and community expectations.

The evolution of the network reflects the establishment and subsequent growth of a start up gas distribution business commencing in the early 1980s with the construction of the high pressure backbone network and the rollout of local distribution networks into existing established areas. The focus moved during the 1990s into greenfield areas, and strengthening the high pressure network to support the continued reach and penetration of gas. During the first decade of the current century, this pattern has continued with the proportion of existing homes and businesses connected to gas plateauing, but with the need to strengthen the high pressure feeder infrastructure growing in importance. Development through these phases has resulted in changing management focus for the network over time.

Today the ongoing network extension investments are directed towards the areas of new estates, infill developments and the regeneration areas of existing suburbs and commercial precincts. Accompanying the network rollout, the connection of both domestic and business customers has progressed at rates relative to community and lifestyle demands. This has followed a pattern of network establishment and organic growth, being serviced from the foundation platform of the network. ActewAGL Distribution must continue to invest in the network for future demand by reinforcing the backbone of the network and major facilities.

A result of industry wide increases in demand in competing eastern Australian gas markets, today's key network investment drivers are threats to security of supply and the need to maintain supply reliability in the face of them. The ACT gas network is particularly subject to upstream supply decisions and disruptions, and shortfalls in gas as a result of insufficient nominations or upstream constraints can have a catastrophic impact on the network during peak winter demand periods. This drives the need for efficient investment in infrastructure that is capable of responding to shortfalls in supply and able to ensure that the short and sharp morning and evening peak loads continue to be supplied.

In response to this driver, ActewAGL Distribution proposes to loop the Hoskinstown to Fyshwick Pipeline during the access arrangement period as the preferred option within the control of ActewAGL Distribution that ensures security of supply. This will provide an appropriate level of capacity to manage shipper nomination risks and/or plant/pipeline operator constraints upstream of the network.

ActewAGL Distribution must also continue to prepare for the carbon constrained economy. This means additional investments in upgrading existing ageing and obsolete network equipment that contribute to fugitive emissions, enhancing emission controls, and increasing measurement accuracy and compliance. ActewAGL Distribution is also seeking to meet the increasing customer demand for information on energy usage and network services through the trial of technologies such as smart meters.

In this access arrangement period, ActewAGL Distribution will implement a widespread meter replacement program, and investigate options for gas smart metering through a multi-utility smart metering trial (*Project MIMI*). ActewAGL Distribution will also undertake a program of upgrading facilities (TRS and PRS) where equipment has reached the end of its effective life and is no longer fit for purpose or supported by equipment manufacturers. As part of this replacement and upgrade program, ActewAGL Distribution is also taking the opportunity to enhance system monitoring and critical pressure monitoring points on the network.

New more efficient domestic appliance technologies are changing the local demand profile. In response ActewAGL Distribution will continue to build and reinforce local networks to meet the capacity requirements of the unique ‘peaky’ and highly seasonal domestic load profile which exists on the network, in order to maintain system integrity.

3.1.1 Asset management contracting and governance

ActewAGL Distribution contracts out the management of its gas distribution network to JAM under the Distribution Asset Management Services (DAMS) Agreement. This contract makes up a key part of its gas network asset management and risk strategy.

The following sections discuss high level arrangements in place under the DAMS Agreement, and ActewAGL Distribution’s relationship with JAM. Specific governance arrangements under the DAMS, are discussed later in this chapter at section 3.5.

3.1.1.1 Origin of the DAMS contract and services covered

The DAMS Agreement is a contract between ActewAGL Distribution and Jemena Asset Management Pty Ltd. The contract was established at the same time as the formation of the Joint Venture between ACTEW and AGL, in October 2000. The joint venture brought together the ACTEW-owned electricity and AGL-owned gas network and retail businesses to form an energy distribution and retail joint venture.

In 2000, Agility Management Pty Ltd, a fully owned subsidiary of AGL, was the other party to the DAMS Agreement. Following the October 2006 business dealings between AGL and Alinta, and the subsequent purchase of Alinta by Singapore Power in 2007, ActewAGL Distribution is now owned equally by ACTEW Corporation and Jemena Networks (ACT) (a fully owned subsidiary of Singapore Power).

The DAMS Agreement, covering what has become the ACT, Queanbeyan and Palerang gas network, is now held by JAM. Jemena Networks (ACT) and JAM are owned by Jemena Ltd, and owned in turn by Singapore Power.

In this context, the management of the gas network was not part of the activities of the Partnership that was later outsourced. Rather, the outsourcing arrangement has continued the *status quo* whereby the operation and management of the gas network continue to be undertaken by a specialised asset management company with a past history in managing the network.

The precise services covered by the 2009/10 agreement are set out in the Service Plan at attachment Q to this access arrangement information and all are relevant to the provision of reference services. In addition, capital works in relation to routine mains and customer service connections are carried out by JAM under a Supplementary Agreement to the

DAMS Agreement. The outcomes under the DAMS Agreement and the Supplementary Agreement were subject to review by the ICRC in relation to the earlier access arrangement period.

Fees payable under the DAMS Agreement are currently determined by reference to the October 2004 ICRC Access Arrangement Decision. As a result they are fixed charges, with the risks associated with cost changes thereby transferred to JAM. Identified efficiencies, discussed below, have reduced this fixed charge.

The Supplementary Agreement contains a schedule of unit rates for conducting routine capital works associated with network expansion and customer connections. The majority of capital works undertaken by JAM are routine works undertaken at these unit rates.

There is no fixed term under either the DAMS or the Supplementary Agreement. There are, however, provisions for the services provided under the contract and the relevant fees and charges to be re-negotiated on an annual basis.

3.1.1.2 Efficiency benefits of outsourcing

The potential efficiency benefits to be derived from outsourcing arrangements have been accepted by regulators. For example, the Victorian Essential Services Commission (ESC) expressed the view in its Draft Decision on the 2008-2012 Gas Access Arrangement Review that:

> A prudent distributor is not necessarily likely to undertake all the activities required in order to deliver the Reference Services. It is consistent with good industry practice that various functions may be outsourced to an external provider of services that has specialist skills in undertaking particular activities. For example, a distributor may engage a specialist provider to undertake call centre activities, meter reading, gas field operations or specific capital projects. There may be efficiencies and cost savings that are achievable by outsourcing activities to a specialist provider. [27]

Regulators have also recognised that efficient outsourcing arrangements can include additional payments to the contractor. Again, in the case of the ESC:

> The Commission accepts that any third party contractor will require compensation for its endeavours over and above the actual cost of undertaking the contracted activities. A third party contractor would expect to be able to recover all of the economic costs that it incurs to provide the outsourced activity and would expect to benefit from superior performance. Otherwise it would not contract to undertake those activities. Such compensation is not necessarily inconsistent with an efficient level of costs, particularly where the contractor has the ability to provide the service at a lower cost than the distributor could do so itself or obtain elsewhere. Further payments above direct costs may [..] also provide a return to the contractor for:
>
> - the assets employed by it in the provision of the outsourced services;
> - efficiencies on the part of the contractor over the life of the contract; and
> - the contractor's common costs. [28]

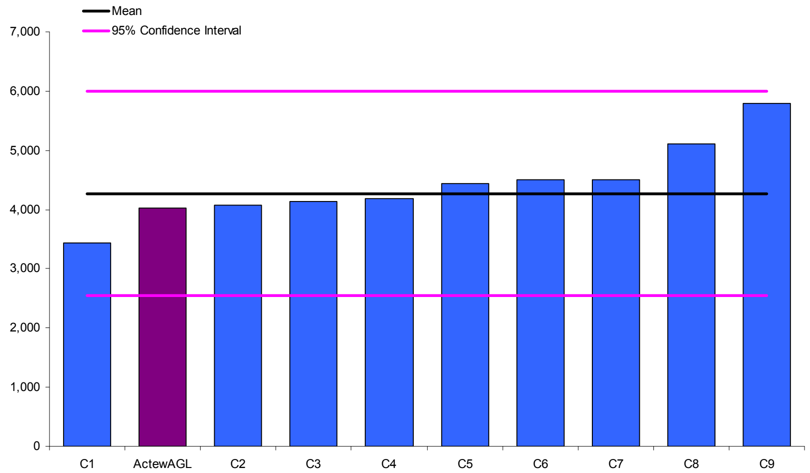
[27] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p 39
[28] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 52, footnote 30

There is considerable potential for JAM to exploit economies of scale and scope in undertaking the activities under the DAMS Agreement. JAM is a leading provider of infrastructure management services to the utility sector. The JAM team comprises more than 1000 staff delivering services to a wide range of assets and third parties in Victoria, Tasmania, New South Wales and Queensland, in addition to services provided to ActewAGL Distribution in respect of its gas network. These benefits of scale and scope are also complemented by JAM's past history in managing the ACT network (through its predecessor organisations).

In addition, operating expenditure fees agreed under the DAMS are fixed, which in effect transfers the risk of cost variations away from ActewAGL Distribution to JAM. As a result, the costs to ActewAGL Distribution under the DAMS Agreement are lower, on a risk adjusted basis, than if ActewAGL Distribution were to provide those services in-house. The report on risk management commissioned from Marsh Ltd by ActewAGL Distribution to support its claim for self-insurance costs (at attachment C to this access arrangement information) recognises that several significant risks are passed to JAM under the DAMS Agreement.

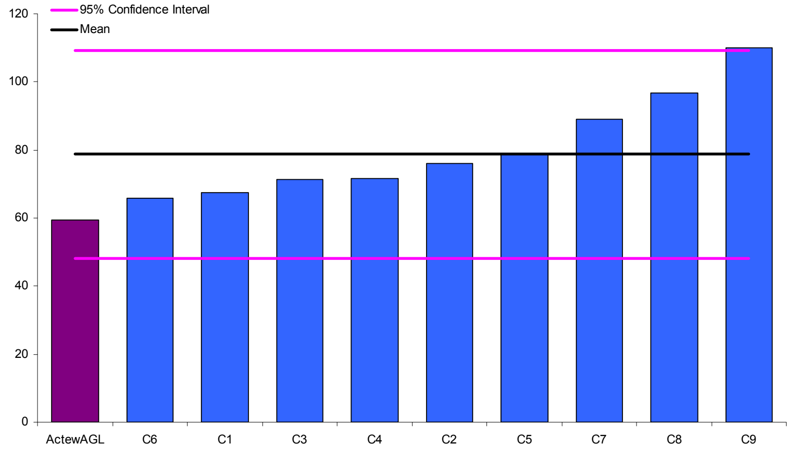
A detailed benchmarking analysis has been undertaken of ActewAGL Distribution's operating costs in the lead up to this access arrangement revision process. The benchmarking report is provided at attachment E to this access arrangement information. Some of the key conclusions from the report are shown in Figure 3.1 and Figure 3.2.

Figure 3.1 Operating expenditure (2008$) per length of mains (with normalisation)



Note: Information is for the most recent year available

Figure 3.2 Operating expenditure (2008$m) per customer (with normalisation)



Note: Information is from the most recent year available.

This benchmarking analysis shows that ActewAGL Distribution's operating expenditure costs, after normalisation, compare favourability with other Australian gas distribution businesses.[29]

3.1.1.3 Arm's length relationship

While it is recognised that there is the potential for significant efficiency gains to flow from outsourcing arrangements, regulatory bodies seek to establish that the parties to outsourcing arrangements have an incentive to achieve commercial outcomes for both businesses.

In this regard ActewAGL Distribution highlights that the interests of ActewAGL Distribution and JAM are not directly aligned. The ownership structure of ActewAGL Distribution is a 50:50 joint venture between ACTEW and Jemena Networks. In contrast, JAM is 100 per cent owned by Jemena. ACTEW would not be neutral to a non-commercial contract arrangement between ActewAGL Distribution and JAM, as it would not receive any benefit from unjustifiably high costs incurred by JAM. In contrast, ACTEW receives 50 per cent of the benefit of any cost savings achieved during the access arrangement period. As a result, ACTEW has an incentive to ensure that the outsourcing arrangements reflect a commercial arms-length outcome.

In addition, the corporate and commercial management structures of the Partnership are such that Jemena does not have undue influence over the outcomes of the DAMS Agreement. Neither of the partners of ActewAGL Distribution can determine the partnership's financial and operating policies. Neither partner has control of the gas distribution network business: only acting together do the partners have control. This applies in respect of legal rights, in respect of practical influence, and in respect of practice and patterns of behaviour.

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[29] Details of the methodology used in undertaking this benchmarking analysis, including normalisation for factors such as dual-sided street reticulation, are set out in the operating expenditure benchmarking report at attachment E to this access arrangement information.

All Board members are required to sign an undertaking that they will act in the interests of the Joint Venture, rather than their individual companies. The ActewAGL Distribution Joint Venture Board is comprised of three ACTEW representatives, two Jemena representatives and one AGL representative. The ACTEW Board chairman is currently the chairman of the ActewAGL Board.

Under the DAMS Agreement, a representative is appointed by ActewAGL Distribution to be its exclusive delegate and to make operational decisions under the agreement. Such operational decisions are wide ranging and substantive and include decisions to undertake benchmarking of the prices charged by JAM and price negotiations under the agreement. The appointed representative is currently the Manager Gas Networks, who is employed by the ActewAGL Distribution partnership.

All of the above factors mean that the contractual arrangements are effective in ensuring that the businesses operate on an arm's length basis.

3.1.1.4 Market testing

The outsourcing arrangements were determined directly between the parties and have not been subject to competitive tender. However, there are provisions in the DAMS Agreement that allow for market testing of the costs incurred under the arrangement, both on an on-going basis and in instances where ActewAGL Distribution has concerns that JAM's price does not reflect market rates. The threat of market testing provides an important incentive for a commercial outcome to be agreed between the parties to the contract.

JAM is required to provide market analysis or benchmarking (both on an annual basis and on request) that establishes that JAM is proposing to provide the Asset Services in an efficient manner at a cost consistent with market prices for services of the same nature and quality.

Where JAM's price is inconsistent with the indicative market price arising from the benchmarking analysis, ActewAGL Distribution can require JAM to conduct a competitive pricing process to allow the service to be provided by a third party. JAM has the right to adjust its fees to match that of the lowest acceptable competitive cost arising from the competitive pricing process.

3.1.1.5 Synergies with ActewAGL Distribution's other businesses

Notwithstanding that cost efficiencies are expected to primarily flow from the economies of scale and scope achievable by JAM, there are also provisions under the DAMS Agreement for identifying synergies with ActewAGL Distribution's existing businesses. Where such synergies are identified, the services can be removed from the scope of services covered by the DAMS Agreement and instead provided in-house.

It is to be expected that the opportunities for realising such synergies may be relatively limited. However, examples of where ActewAGL Distribution has identified synergies and removed services from the scope of the DAMS Agreement to date include:

- digital mapping services for new assets (now undertaken by Ecowise Environmental); and
- meter reading (undertaken by a direct contract between ActewAGL Distribution and Fieldforce Services to realise cost savings from readings across water, gas and electricity).

Where these services have been removed from the scope of the DAMS, the fee paid to JAM has been reduced correspondingly.[30]

As a result, the contractual arrangements allow for the active consideration of whether greater efficiencies can be achieved at the margin by bringing selected services in-house, whilst allowing for the achievement of efficient outcomes overall through the outsourcing of the bulk of the operation and management activities to a specialist asset management business whose scale of activities is significantly larger than that of ActewAGL Distribution.

3.2 Network planning components

Planning, developing and managing the gas distribution network to meet regulatory obligations is a complex task. Decisions to maintain, expand and extend the network are undertaken within a robust network planning framework which in turn must be flexible enough to encompass changing market dynamics and all new and existing regulatory obligations across both NSW and the ACT.

ActewAGL Distribution's approach to network planning and asset management is based on sound and up-to-date network engineering and management practices delivered through its asset management contract, and the application of good industry practice.

The key categories of network expenditure are capacity development, market expansion and stay-in-business expenditure. Forecasts for these expenditures are derived through detailed analysis of network inputs (demand, regulatory/technical requirements, asset condition, and so on), to develop options that maintain safe, secure and reliable supply. The process for developing expenditure forecasts for each of these categories is described below.

3.2.1 Capacity development planning

Capacity planning and development ensures that the network is able to meet gas demand. As capacity development projects are driven by demand, capital expenditure under this category is justified under Rule 79(2)(c)(iv), which states that capital expenditure is justified if it is necessary:

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

[30] Meter reading services continue to be managed by JAM, but the cost of readings is based on the actual contracted meter reading rates with Fieldforce Services. As a result, the cost savings from integrated meter reading are directly passed through to ActewAGL Distribution.

The processes described in this section show how capital expenditure is derived through changes in demand by reference to network monitoring and modelling. Specific projects that emerge as a result of these processes are discussed in more detail in chapter 6 of this access arrangement information covering capital expenditure. The discussion in this section, however, is key to showing how forecast capacity development expenditure conforms to the criteria under Rule 71(1)(a).

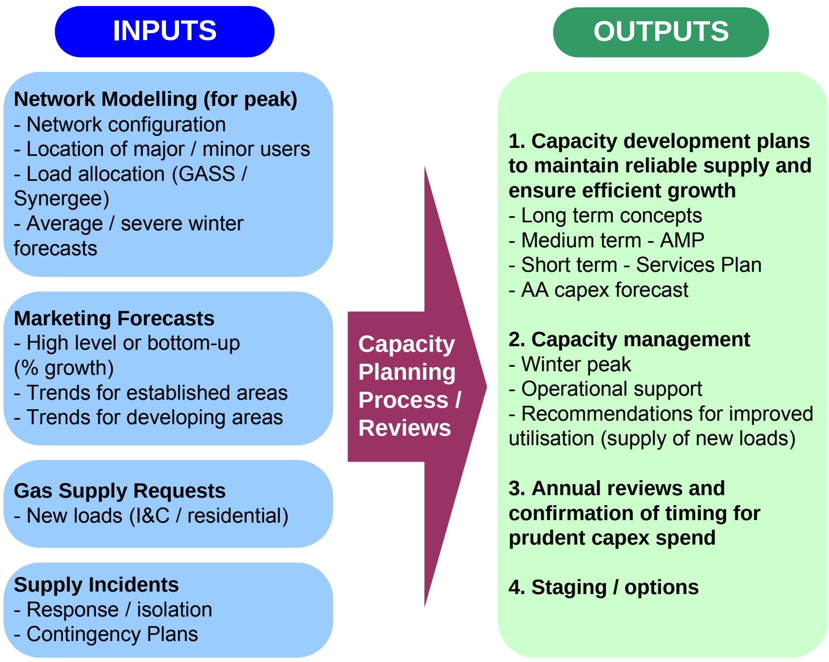
3.2.1.1 Capacity planning process

The capacity planning process is a core component of the annual planning cycle. The objectives of the capacity planning process are to:

- Maintain safe and reliable supply;
- Formulate capital projects for efficient growth of infrastructure;
- Optimise efficient costs through selection of options;
- Undertake long term configuration planning;
- Undertake capacity planning for client opportunities (for example, power stations);
- Improve utilisation (for example, through organic growth); and
- Improve security of supply.

As shown in Figure 3.3, key inputs to the capacity planning process are network monitoring and modelling, marketing demand forecasts, gas supply requirements, and supply incidents. These are described below in respect of the annual capacity planning cycle.

Figure 3.3 Capacity Planning Process



The capacity planning process delivers two key outputs. These are capacity development plans and capacity management operational support and recommendations.

Capacity development plans set out the capacity development expenditure needed to maintain reliability and support additional growth in demand. Typical capacity development capital projects include mains extensions, mains interconnections, and installation or upgrade of regulators and facilities.

Capacity development planning includes long term planning of the needs to develop and reinforce primary backbone infrastructure, including other major upstream infrastructure to accommodate new developments, as well as medium and short term planning of capacity development needs in the next five years (in the Asset Management Plan (AMP)) and the coming year (in the Service Plan). The capacity development planning process also gives rise to forecasts for inclusion in this access arrangement information, reflecting those aspects included in the AMP.

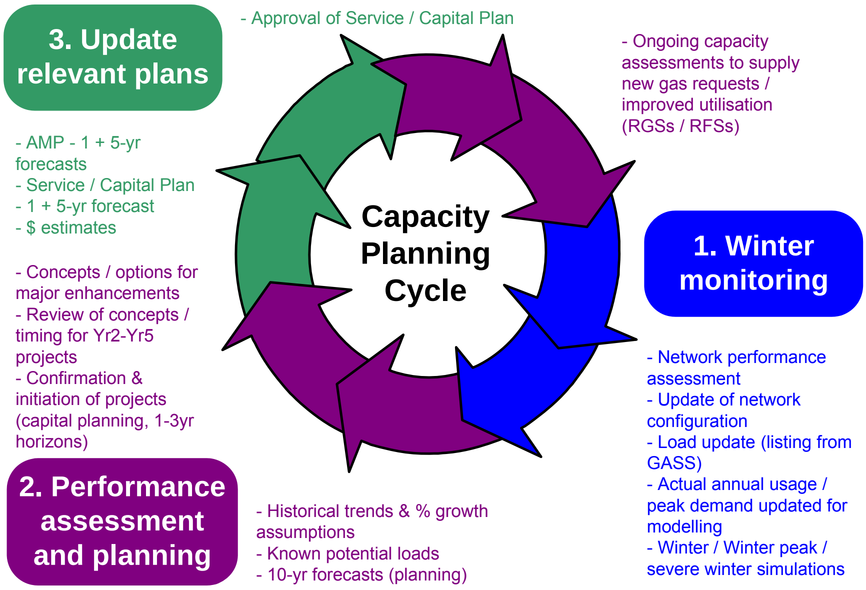
Capacity management operational support and recommendations identify the monitoring and operational activities required to improve network utilisation and to manage gas supplies through peak periods.

The capacity planning process also serves to review the timing and need for previously identified projects on an annual basis, as well as project options and staging (that is, project acceleration or deferral).

All of these outputs are inputs to the Service, Capital and Asset Management plans. Capacity development plans provide the technical solutions to reinforce the network to accommodate projected growth in load, to ensure reliable supply and to improve the security of supply.

The annual capacity development cycle, showing the role of key inputs to the process, is shown in Figure 3.4.

Figure 3.4 Annual capacity development planning cycle



Stage 1 – Winter Monitoring

Given ActewAGL Distribution's predominantly residential customer base and the region's cold winters, gas distribution loads peak in winter. Managing the winter peak is thus a major driver for capacity development. The annual capacity development planning process therefore begins with winter monitoring of the network. This involves placing gauges at various supervisory control and data acquisition (SCADA) monitoring points on the network to measure actual pressure and flow data.

Monitoring information is then supplied to the network configuration model and the GASS mainframe system (discussed further below) to develop and validate an up-to-date model of the network and current winter demand. This performance analysis is conducted on models of the ActewAGL Distribution network using SynerGEE network analysis software.[31] The models are used to identify network capacity constraints and to evaluate design options to enhance the capacity in the network.

Stage 2 – Performance assessment and planning

The annual update of the network model to reflect current demand is then used to confirm the need for capacity development expenditure planned for the next year and identify whether any planned expenditure should be deferred to later years or other projects brought forward in response to measured demand. This review also usually results in the identification of a number of small miscellaneous capital expenditure items to repair the network and prepare it for the next winter. Changes in forecast expenditure can be driven by significant new large users, or developments, as well as changes in load characteristics and usage patterns. This ensures that investment in the network is efficient and not made before it is needed. A number of planned capacity development projects in the earlier access arrangement had timing adjustments as a result of this kind of analysis. This is discussed further in chapter 6 of this access arrangement information.

Other inputs to the network model include historical trends and growth assumptions (derived from existing load information from the GASS system) and known potential new loads that have a reasonable probability of eventuating.

Future capacity development needs are developed by simulating severe winter conditions using a 1 in 20 severe winter demand scenario and the following acceptable operating levels:

- Network pressures close to or below 70 kPa for medium pressure networks and 525 kPa for secondary networks (that is, the minimum requirements for reliable supply);
- Capacity of facilities (SDRS / PRS, etc) nearing design limits; and
- Supply reliability at risk (for example, to meet customer contractual obligations for large I&C users or users with 100 kPa metering pressures).

[31] The SynerGEE® network analysis software was formerly referred to as the "Stoner model".

With robust computer modelling, timing and staging of capacity development projects can be determined to minimise the risk to supply reliability. Projects are planned for completion in time to mitigate the risk of an unacceptable loss of supply. Concepts and options for major enhancements are also developed, which both inform, and are informed by, the strategic plan for the network.

Stage 3 – Update plans

Outputs from the capacity planning process are incorporated into the Capital, Services and Asset Management Plans. These provide the basis for expenditure approvals for the coming financial year as part of ActewAGL Distribution's annual planning cycle described in section 3.3 below.

GASS mainframe system

GASS is a multifunctional mainframe system and database that provides key business tools and data management services for the ActewAGL Distribution gas network. The GASS system functionality and services include:

- asset records;
- meter management;
- meter reading & billing;
- works management;
- market participation and management; and
- internal controls and reporting.

The GASS system is a key input to the capacity planning process as it holds meter reading and billing data for the network. As such it provides key input data for determining network demand. The GASS system also includes information about assets, their age and condition. This information supplements capacity planning by identifying opportunities where capacity development expenditure can be coupled with the need for asset replacement and renewal. This leads to more efficient and holistic network planning that minimises capital expenditure on the network.

3.2.2 Market expansion

Market expansion expenditure is that expenditure needed to directly meet growth in customer numbers and connections. The relevant Rules for this expenditure are Rule 79(2)(c)(iii), which states that capital expenditure is justified if it is necessary to comply with a regulatory obligation or requirement, and Rule 79(2)(b) related to the network present value of incremental revenue generated as a result of expenditure. For expenditure that satisfies Rule 79(2)(b), there are additional requirements under Rule 79(4).

The other relevant Rule for this category of capital expenditure is Rule 82(1), allowing a user to make a capital contribution towards a service provider's capital expenditure.

The processes described in the following sections show how market expansion capital expenditure and capital contributions are derived. Specific expenditure forecasts and projects that emerge as a result of these processes are discussed in more detail in chapter 6 of this access arrangement information covering capital expenditure. The discussion in this section, however, is key to showing how forecast capacity development expenditure conforms to the criteria under Rule 71(1)(a).

3.2.2.1 Satisfaction of Rule 79(2)(c)(iii)

Market expansion expenditure refers to the capital and operating expenditure required to directly meet growth in customer numbers and connections, and is driven by customer requests for connection. ActewAGL Distribution is required to connect customers to the gas network, both as a general obligation, and as a special condition under its licence. Section 31 of the *Utilities Act 2000* (ACT) states:

> A licence to distribute gas is, in addition to the conditions mentioned in section 25, subject to the condition that the distributor must—
>
> (a) on request by a gas supplier or other person; and
>
> (b) on payment to the distributor of any relevant capital contribution charge;
>
> connect the premises to which the request relates to the distributor's network.

Section 81 of the Act also states:

> A gas supplier must, on application by a person, and in accordance with the supplier's standard customer contract, request a gas distributor to—
>
> (a) connect the premises to which the application relates to the distributor's network; or
>
> (b) vary the capacity of the connection between the premises to which the application relates and the distributor's network.

ActewAGL Distribution is therefore required under statutory and licence obligations to connect customers to its network. The only conditions to that obligation are that it must receive a request, and that the customer must pay relevant capital contributions.

Market expansion expenditure is therefore justified under Rule 79(2)(c)(iii).

3.2.2.2 Relevance of Rules 79(2)(b) and 79(4)

As ActewAGL Distribution has a clear regulatory requirement to connect customers to the network, capital expenditure under this category is not *driven* by Rule 79(2)(b). This Rule, and details under 79(4), is relevant, however, to determining the *level* of conforming capital expenditure and appropriate capital contribution amounts that may be required. Capital contribution values are determined by application of the Request Utility for Gas Supply (RUGS) process described below. ActewAGL Distribution therefore provides information on its RUGS process, rather than details of individual connections processes, as these projects number into the thousands each year.

3.2.2.3 Forecast capital contributions

In cases where a routine or minor mains extension is required, ActewAGL Distribution recovers capital contributions through retailers who pass the charge onto the relevant customer. There are therefore no relevant contractual agreements between ActewAGL Distribution or JAM and the customer. Capital contributions for non-routine capital works are infrequent and are charged via the retailer to end-users. There are therefore no contractual agreements associated with capital contributions.

3.2.2.4 Market expansion planning process

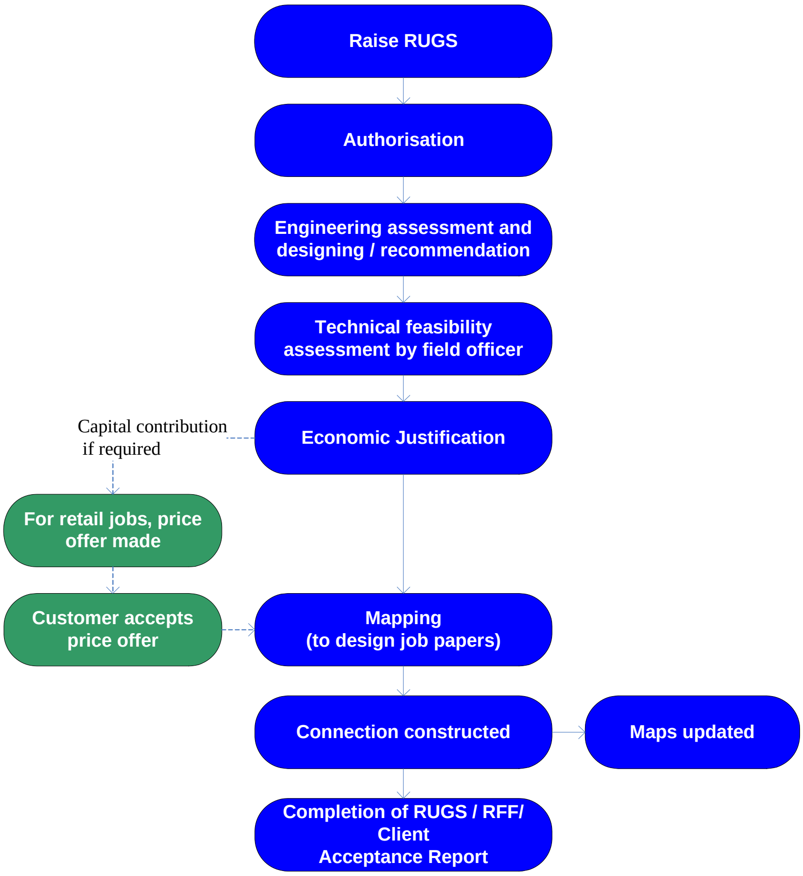
The market expansion process is designed to ensure that new connections expenditure is efficient, and to calculate any relevant capital contribution amounts. Most applications for connection relate to routine capital works, and are therefore managed through the RUGS process. The RUGS process is used largely for initiation and tracking of routine connections work, but it is also used to track other capital projects, including some stay in business works such as mains upgrades.

The RUGS process guides the connection of new customers and is comprised of the following key stages:

1. an initial request for gas supply by a potential customer, leading to a RUGS being raised;
2. a technical feasibility study and engineering design for the requested connection;
3. a financial assessment of the required works for the requested connection and, depending on the results, the determination of a capital contribution amount;
4. connection offer being made, accepted or rejected;
5. connection works and mapping; and
6. final documentation and client acceptance of the connection works.

A detailed demonstration of this process is shown in Figure 3.5. This process makes up part of JAM's gas connections management system.

Figure 3.5 RUGS for routine capital works



For routine capital works, when a request for gas supply is raised through RUGS, the system checks whether the connection can be located on existing mains, or whether a *non-standard service* or mains extension is needed. If a mains extension is needed, a financial analysis determines whether ActewAGL Distribution may need to charge the end user for a capital contribution. The capital contribution charge is calculated consistent with the ICRC *Gas Network Capital Contributions Code* under the Utilities Act.

The economic evaluation for the capital works is performed using a discounted cash flow model. The financial indicators calculated for the assessment are earnings before income and taxes, net present value and internal rate of return. If the financial indicators show that the required works are uneconomic but the customer still requires the extension, a capital contribution is charged to make up the shortfall. Details of the financial assessment process are set out at attachment Q to this access arrangement information.

3.2.3 Stay in business

Stay in business expenditure ensures safety, reliability and security of the network. Capital expenditure in this category is therefore justified under Rules 79(2)(c)(i)-(iii) which state that capital expenditure is justified if it is necessary:

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

(ii) to maintain the integrity of services; and

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

The processes described in this section show how capital expenditure is derived to ensure the safety and integrity of services are maintained. Where relevant, technical or regulatory requirements are referenced in respect of individual projects in the chapter 6 of this access arrangement information.

The discussion is this section is also key to showing how forecast capacity development expenditure conforms to the criteria under Rule 71(1)(a).

3.2.3.1 Stay in business expenditure planning

Stay in business expenditure ensures reliability and security of supply, asset protection, and integrity of the network. It includes a mix of capital and operating expenditure and addresses maintenance (asset services), improvement, renewal and replacement of network assets. Stay in business projects are identified through the asset management process, specifically through activities such as performance monitoring, incident management, benchmarking, analysis of cost trends and compliance with technical standards.

The GASS mainframe system plays a key role in determining efficient stay in business expenditure. The database is the repository for information on network assets, including the number of assets of each type, asset age, maintenance schedules and asset condition. For example, when a new asset is installed, information is entered into the database about the type of asset, when it was installed, and maintenance criteria for the asset, including appropriate maintenance schedules and expected operating life. The maintenance criteria are determined through vendor specifications and/or asset management technical policies developed by JAM. The GASS system then generates maintenance orders over time in line with schedules included in the database. When maintenance is undertaken the database is updated and specific information on asset condition, if relevant, is recorded.

A complete record and history of individual assets can therefore be developed from information in the GASS system, as well as information on asset classes. This allows detailed information on past and expected maintenance to be compiled for consideration of available capital and operating expenditure trade-offs, as well as providing robust information on where asset condition may drive replacement expenditure.

Capital projects are initiated when an asset is assessed as being ‘not fit for purpose’ and there are no practicable remedial strategies that could be implemented to:

- adequately address the risk posed by failure of the asset;
- improve the performance of the asset; or
- meet compliance requirements.

Stay in business projects are divided into four categories of work being: mains and service renewal and upgrade; facilities renewal and upgrade; meter renewal and upgrade; government authority work; security of supply and other.

The Lifecycle Plan, included in the AMP, sets out the outcomes of this analysis and expenditure required to ensure that asset integrity, reliability and safety is maintained.

3.3 ActewAGL Distribution's annual planning cycle

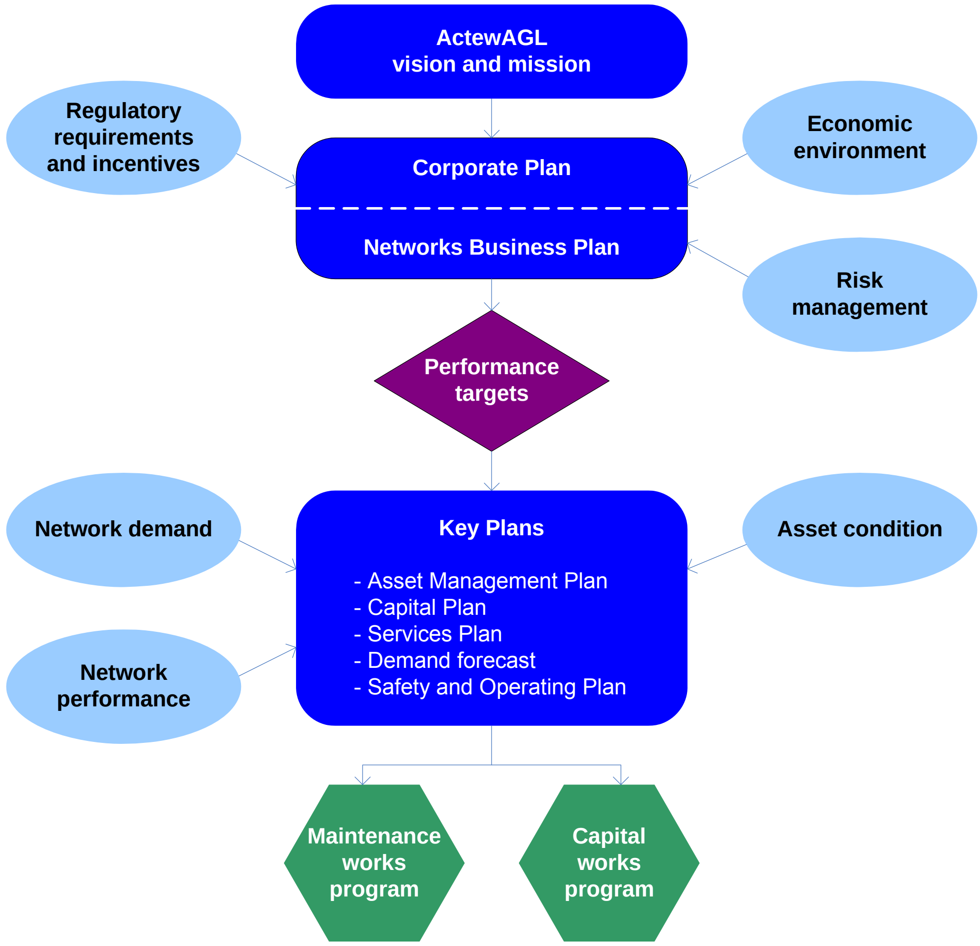
ActewAGL Distribution utilises an integrated network planning and performance management process. ActewAGL Distribution's broad approach to network planning and management is summarised in Figure 3.6.

Networks Division is a primary part of ActewAGL Distribution with responsibility for the control and operation of the gas distribution system. The Networks Business Plan supports the Corporate Business Plan and is part of ActewAGL Distribution's annual planning cycle. The Networks Business Plan sets the overarching goals and targets that are necessary for the implementation of longer term plans and projects for the coming financial year, and includes human resources management, business processes and stakeholder management.

The Networks Business Plan is finalised at the conclusion of the planning and budgeting process and communicated to relevant ActewAGL Distribution personnel in time for identified priorities to be implemented in the coming financial year. Priorities under the Network Business Plan are set with reference to risk management processes.

The development of specific network management and planning outcomes then flow from the Networks Business Plans under gas network specific sub-plans. The principal gas network planning document is the AMP. The AMP includes a detailed plan for the coming year and higher level forecasts for the following 5 years. The AMP incorporates information from a number of sub-plans. These plans are discussed further in section 3.4 below.

Figure 3.6 Overview of ActewAGL Distribution's annual gas network planning and management process



The AMP is provided by JAM to ActewAGL Distribution each year for agreement. The AMP must integrate with the higher level Networks Business Plan and be consistent with ActewAGL Distribution's network development and management objectives and priorities. It must also take into consideration compliance with relevant regulatory obligations. Priorities are then set for the following financial year and reflected in the AMP.

The development and review of the AMP is timed to coincide with ActewAGL Distribution's annual planning and budget cycle, to ensure that the coming year's agreed capital and operating expenditure is approved by the end of the annual budget cycle. These processes are set out in the ActewAGL Networks Procedure EN4.09 P2.

The network and asset management planning processes followed for the gas distribution network are essentiality the same as those followed for ActewAGL Distribution's electricity network. This process was reviewed by consultants to the AER, Wilson Cook and Co Ltd, as part of the recently completed 2009-14 electricity network price review process. Wilson Cook concluded in its final report that the policies and procedures followed by ActewAGL

Distribution were reasonable.[32] This conclusion was accepted by the AER in its draft decision (also reflected in its final decision) where it stated:

> During meetings with ActewAGL planning staff and Wilson Cook, AER staff had the opportunity to review the application of ActewAGL's planning processes in the context of a sample of key projects which are major contributors to the proposed capex program. As a result of this review, the AER and Wilson Cook are satisfied that ActewAGL had observed appropriate processes and procedures in determining the scope, timing and need for these projects.[33]

3.4 Key planning documents

The key planning documents for ActewAGL Distribution's gas network planning and asset management framework are the Asset Management Plan (1+5 year),[34] the Demand Forecast (5 year), the Capital Plan (1+5 year), the Service Plan (1 year) and the Safety and Operating Plan (1 year). These plans contain long-term investment and asset management objectives and strategies, as well as criteria and procedures for identifying and assessing operations and trade-offs.

The review of the AMP and presentation and approval of key plans such as the Service and Capital Plans provides the framework within which ActewAGL Distribution provides high level direction for the development of the network, and assesses the relative merit of capital and operating expenditure, capacity development, market expansion and stay in business expenditure.

ActewAGL Distribution's regulatory obligations, both in the ACT and NSW, as well as forecast demand, are key inputs into each of the plans. The plans also reference subordinate plans, policies, procedures and standards. Where relevant, these subordinate documents are provided as attachments to this access arrangement information, or are available for inspection by the AER.

3.4.1 Asset Management Plan

The Asset Management Plan has as its basis ActewAGL Distribution's asset management priorities, key performance indicators and capital projects for the coming financial year, as well as providing a forecast of asset management priorities and capital projects for the following five years.

The AMP is prepared by JAM reviewed by ActewAGL Distribution each year to integrate with the ActewAGL Distribution planning cycle described above. The AMP includes at its front the key assumptions that JAM uses to develop the plan. These reflect ActewAGL Distribution network development and management objectives and priorities. This process is represented in Figure 3.7.

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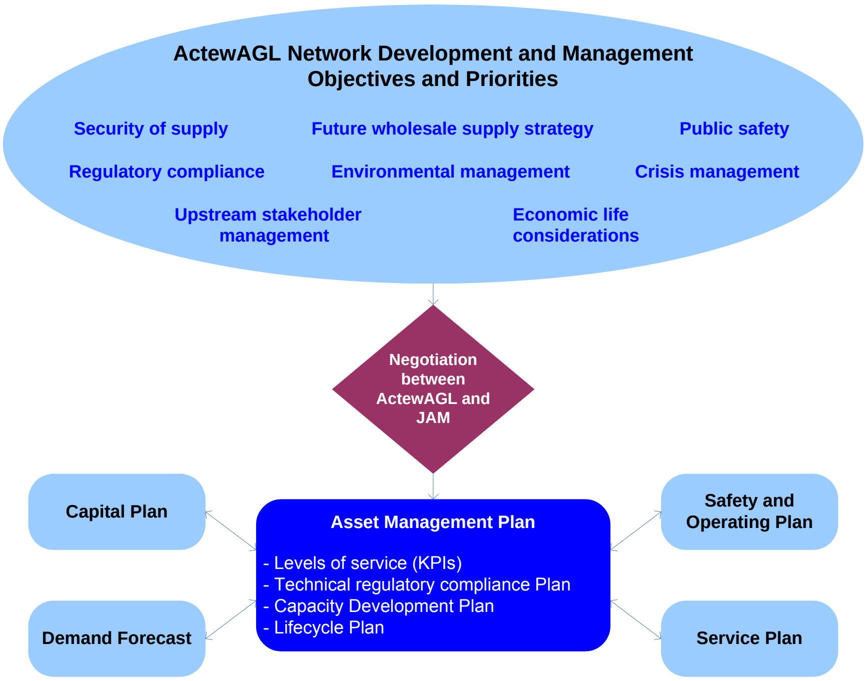
[32] Wilson Cook and Co Ltd, *Review of Proposed Expenditure of ACT and NSW electricity DNSPs, Volume 5 – ActewAGL Distribution*, Final, p 15

[33] AER 2008, ACT distribution determination 2009-10 to 2013-14: Draft decision, 7 November, p 65

[34] The term *1+5 year* means one year of detailed planning information and five years of forecasts.

Figure 3.7 Asset Management Plan development process



As outlined above, the AMP incorporates information from a number of other plans. It also includes the following sub-plans:

- Levels of service;
- Technical Regulatory Compliance Plan;
- Capacity Development Plan; and
- Lifecycle Plan.

These plans are described below.

3.4.1.1 Levels of service

The Service Plan sets out asset performance levels of service, expressed as Key Performance Indicators (KPIs), which reflect the planning outcomes from proposals in the AMP. These KPIs cover inherent asset characteristics and focus on supply reliability, asset integrity and emergency management. The performance levels are reflected in the AMP.

The DAMS Agreement includes initial performance targets for these KPIs, which are negotiated each year as part of the Service Plan (discussed further below). The DAMS Agreement also includes levels for corrective action, to which financial consequences apply, and levels of service that would constitute a material breach, which would trigger the contract default provisions.

The KPIs included in the AMP and Service Plan are not the same as those required to be included in this access arrangement information in accordance with Rule 72(1)(f). While there is some overlap, the KPIs in the AMP are targeted at key contract outcomes identified by ActewAGL Distribution, rather than capital and operating expenditure drivers as required under the Rules. Therefore, some additional KPIs are proposed in this access arrangement information that are not included in the AMP, and vice versa. KPIs for this access arrangement are discussed in chapter 13 of this access arrangement information.

3.4.1.2 Technical Regulatory Compliance Plan

The construction, operation and maintenance of the gas distribution network and trunk pipelines in ACT, and Queanbeyan City Council and Palerang Council areas in NSW are regulated respectively, by the ACT Planning and Land Authority (ACTPLA) and the NSW Department of Water and Energy (DWE).

ActewAGL Distribution being the Network Operator and the Operating Authority, has the responsibility to ensure full compliance with regulatory obligations. This includes:

- Maintaining regular liaison with the relevant regulators in relation to technical regulatory compliance;
- Participating in the development and review of new legislation;
- Developing management tools in accordance with the technical regulatory requirements; and
- Developing management tools to ensure full compliance with existing legislation.

The Regulatory Compliance Plan summarises the governing regulations with which the assets comply and how the associated requirements are managed.

3.4.1.3 Capacity Development Plan

The Capacity Development Plan details the projects required to support the on-going network growth on the ActewAGL Distribution primary, secondary and medium pressure networks. These projects have been identified through the network validation and planning process. The process for developing forecasts for this plan is discussed in section 3.2.1 above.

3.4.1.4 Lifecycle Management Plan

The Lifecycle Management Plan details activities planned in order to create, maintain and operate the assets at the agreed levels of service, while optimising lifecycle costs and managing risk.

Network assets are designed, constructed, operated and maintained to ensure that they safely and reliably meet the expectations of the asset owner and other key stakeholders. These expectations are defined according to the required service levels for the assets. Asset functionality and performance requirements are continually reviewed to reflect changing regulatory, operational and ActewAGL Distribution requirements.

All investment decisions, whether associated with asset creation, operation and maintenance, or renewal and upgrade are made on the basis of levels of service, cost and risk.

3.4.2 Forecast Demand Planning

Demand forecasting is used by ActewAGL Distribution to develop capital expenditure and operating expenditure forecasts. Forecasting of demand is undertaken in two contexts:

1. Long term gas quantity, pricing and connection planning

This forecast is conducted as part of the access arrangement process, generally on a five year cycle with a horizon of up to 10 years. It seeks to: (a) anticipate the number of connections on ActewAGL Distribution's gas network in order to estimate market expansion capital expenditure; and (b) forecast demand for gas volume in order to contribute to the allocation of revenue to consumers and as an input to the capacity planning process. The demand forecast submitted with these access arrangement revisions is described in section 5.2 of this access arrangement information.

2. Local network performance and capacity planning

The capacity planning process is motivated by the requirement to maintain supply reliability during periods of severe winter peak demand. This analysis is conducted on a spatial-level, using simulation of future peak winter demand and taking into consideration the characteristics of each area within ActewAGL Distribution's network, past network performance and long term forecast growth in connections and demand. Through this process, the future demand on specific regions and/or components of the network is developed with the aim of identifying any capacity constraints and developing the capacity development projects required to maintain reliable supply, as discussed in section 3.2.1 above.

3.4.3 Service Plan

The DAMS Agreement requires JAM to submit an annual Service Plan for approval by ActewAGL Distribution. The Service Plan is comprised of two sub-plans: (1) an Operating Plan and Budget; and (2) a Capital Plan and Budget.

The **Operating Plan and Budget** provides information on service provision between JAM and ActewAGL Distribution for the next contract year. The Plan and Budget include specific information on:

- the type of management services and asset services provided by JAM;
- key operating assumptions;
- the key target outcomes sought by ActewAGL Distribution in order to meet its business, operational and service standards; and
- an operating budget and fees for service provision, including a comparison with the operating costs allowed for in ActewAGL Distribution's access arrangement, and benchmarking with the operating costs of other network operators.

The **Capital Plan and Budget** is a rolling six-year plan which is updated and re-issued in the Service Plan on an annual basis. It presents in detail the routine and non-routine capital requirements for the forward contract year, including justifications for all Medium and Major

Capital Projects. A capital budget for each of the subsequent five years is also given. As the Capital Plan is a forward looking plan, forecast cost estimates are derived using a range of assumptions and the best available information at the time. The forecast costs for routine Minor and Medium Capital Works are driven by unit rates which are agreed as per the Supplementary DAMS Agreement. The forecast costs for non-routine and Major Capital Projects are developed on a case by case basis using engineering assessments as appropriate.

3.4.4 Safety and Operating Plan

The Safety and Operating Plan (SAOP) is the primary management document that translates how JAM will comply on behalf of ActewAGL Distribution with the requirements of the following:

- For gas distribution network:
    - *Gas Safety and Operating Plan Code 2000* (ACT)
    - *Gas Supply (Safety Management) Regulation 2008* (NSW)
    - Utility Services Licence (ACT)
    - Reticulator's Authorisation (NSW)
- For licensed pipeline:
    - *Pipelines Regulation 2005* (NSW)
    - Pipeline Licence (NSW)
    - Australian Standard AS2885.3

ActewAGL Distribution has two safety and operating plans relating to this access arrangement, being the ACT, Queanbeyan and Palerang gas network SAOP, and the Hoskinstown to Fyshwick Pipeline SAOP (Licence 29).

The objectives of the SAOPs are to:

- Facilitate the identification and analysis of the risks associated with all hazards which have the capacity to affect the safety of personnel, the public, the environment or the integrity of the assets;
- Detail the policies and procedures developed to mitigate or minimise those risks, and to protect the assets, including the safe operation and maintenance of the assets and the emergency plans;
- Describe the organisational structure and responsibilities of key positions including the positions with approval authority for the procedures and plans; and
- Describe the management of the records necessary to safely operate and maintain the assets and to determine the fitness for purpose of the assets at any stage of their operating life (the Records Management Plan).

3.4.4.1 Contingency Plan

As part of the risk analysis and emergency response requirements of the *Gas Safety and Operating Plan Code*, ActewAGL Distribution has in place a Contingency Plan. The Contingency Plan identifies the triggers and responses in the event of failure of critical infrastructure in the ActewAGL Distribution gas network. The Plan sets out actions to prevent or reduce damage to the network, to minimise long-term failure, control, manage and limit loss of supply to the community, and aid in limiting the time and cost of asset recovery. The Contingency Plan comes into operation only when normal actions available to manage supply shortage, such as market trading, load shedding and curtailment are ineffective in supporting the system.

A total of seven failure scenarios are modelled in the Plan, allowing the impacts of these scenarios to be understood, including expected restoration timeframes. Scenarios include upstream failures at either Moomba or Longford processing plants, and differentiate between a summer (low demand) and winter (high demand) risk and associated response. In addition to setting out appropriate high level responses to an emergency, the Contingency Plan also outlines stay-in-business expenditure to assist in mitigating the risks identified in the Plan.

3.5 Expenditure governance process

Under the DAMS Agreement, ActewAGL Distribution has in place detailed expenditure governance processes to ensure that projects undertaken are prudent, efficient and in line with the overall network strategy. There are separate processes for capital and operating expenditure and depending on whether expenditure is routine and therefore covered by unit rates, or non-routine and subject to an Additional Services Request (ASR).

3.5.1 Operating expenditure governance process

Under the DAMS Agreement, operating expenditure is agreed each year through the approval of the annual Service Plan. The Service Plan sets out specific details of services provided and outcomes to be achieved in the following year, as well as an operating budget to delivery of those services. The DAMS Agreement includes a process for adding to, deleting or otherwise varying the services that JAM provides under the Service Plan, varying fees payable, taking account of significant volume reductions or changes in law or regulations that changes costs for services under the contract.

Throughout the life of the DAMS Agreement, ActewAGL Distribution has not agreed to amend annual fees payable under an annual Service Plan. In addition, asset and management fees payable under the DAMS Agreement have since 2004 been set with reference to the October 2004 ICRC Access Arrangement Decision.[35]

The fees for services covered by the Service Plan are therefore fixed, and JAM bears forecasting costs risks for these activities. Where services are revised, there is a commensurate change in the fees.

[35] Adjusted to remove identified efficiencies and services no longer required, such as digital mapping

For services not covered by the Service Plan, JAM has scope to put forward an ASR to ActewAGL Distribution for approval. ASRs largely relate to capital expenditure, but can also relate to operational expenditure. The ASR process is explained in more detail in the following section in relation to capital expenditure governance.

3.5.2 Capital expenditure governance processes

Capital expenditure is funded by ActewAGL Distribution in line with the provisions of the DAMS Agreement.

Routine capital expenditure is governed by unit rates that are set in accordance with the Supplementary DAMS Agreement. A budget for routine capital works is set each year in the Capital Plan, which is incorporated into the Service Plan. Routine capital expenditure undertaken within the Service Plan budget does not require an ASR. These projects are generally managed through the RUGS process.

All other DAMS Agreement capital works must be approved by ActewAGL Distribution as additional services under an ASR. These works are:

- All non routine work, including routine work that has a non routine component; and
- All projects greater than $100,000 for all job and material types.

As an example, a new estate that included only plastic mains, services and meters, set according to agreed schedule of rates but which had a project/section cost exceeding $100,000, requires an ASR.

This process is shown at Figure 3.8.

The ASR process is designed to provide project governance framework for ActewAGL Distribution approval of relevant capital work. An ASR, when delivered, includes information on:

- need for the project;
- project options;
- scope of work;
- risk assessment;
- financial assessment; and
- tender brief information (if relevant).

JAM also has in place a project *gating* process to manage capital projects and ensure that it has the appropriate sign-offs.

The Gate process is a governance process for determining whether projects should proceed. Each “Gate” represents and assessment and approval step designed to bring discipline to the process of refining project proposals until final approval is given. At various stages revised project estimates are developed using different levels of estimate accuracy commensurate with the stage of the project development. These steps are as follows:

- *Gate 1* to confirm the requirement of the project;
- *Gate 2* completes the feasibility estimate of the project;
- *Gate 3* is the committed estimate to review scope, cost and time of the business case;
- *Gate 4* provides the client approval of the business case;
- *Gate 5* provides the approval to commence construction;
- *Gate 6* includes the operation and maintenance handover; and
- *Gate 7* confirms the project completion.

Figure 3.8 Overview of ActewAGL Distribution /JAM capital governance/approval process

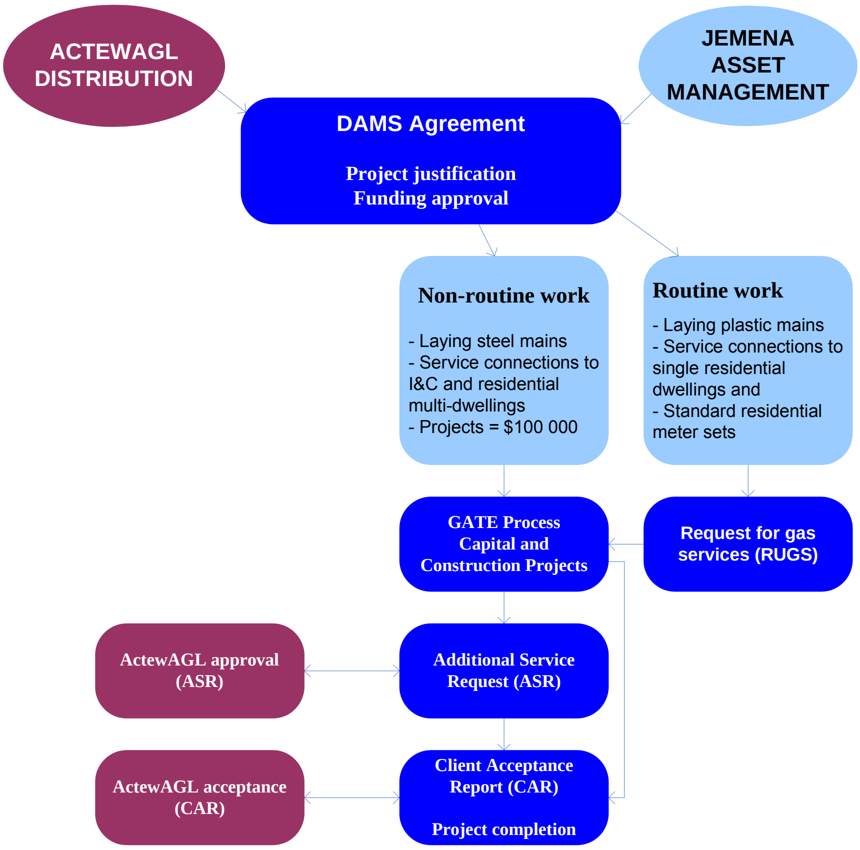


Figure 3.9 shows the ASR and gating process for minor, medium and major projects. In particular, it shows points at which ActewAGL Distribution approves the release of funds (the ASRs), and other ActewAGL Distribution approvals at various stages including identifying the need for the project, approving the business case and finalising the delivery of the project (the gates signified by G1, G2, and so on).

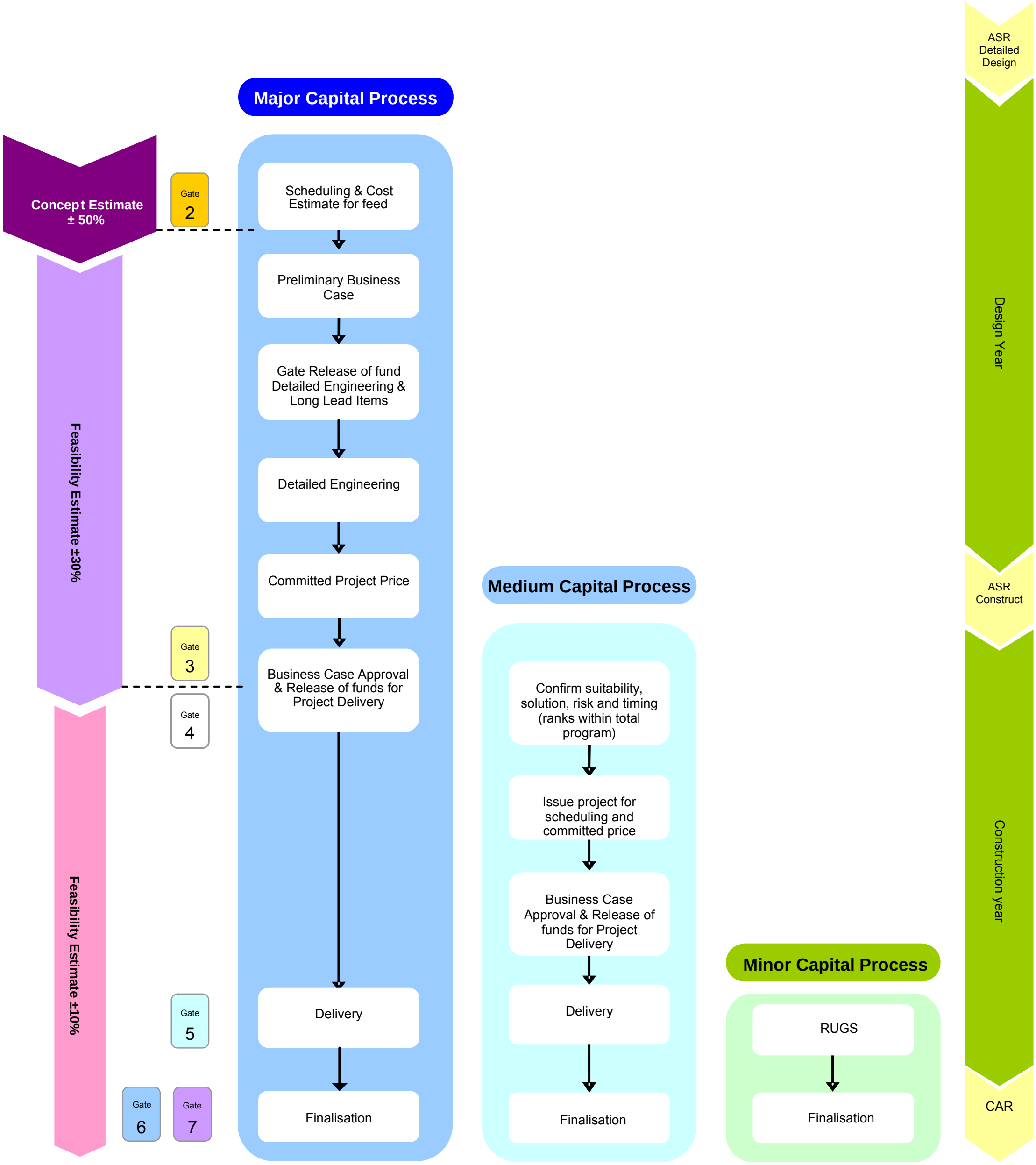
One stage shown in Figure 3.9 but not yet discussed here is the Client Acceptance Report (CAR) process. The CAR is the document used to communicate to ActewAGL Distribution the successful completion of agreed scope of work for the price set out in the ASR, and typically triggers the final invoice for the job.

All jobs with an ASR that involve the construction or modification of physical assets are finalised with a CAR. This is because a key component of the CAR is a written guarantee that JAM provides ActewAGL Distribution by having the Capital and Construction Manager and the Asset Manager sign the CAR prior to it being submitted to ActewAGL Distribution.

The signature from the Capital and Construction manager confirms that JAM has built the asset to agreed specifications and commissioned it appropriately, and that the asset complies with relevant codes and is fit for purpose. The signature from the Asset Manager confirms that the new asset has been accepted on behalf of ActewAGL Distribution from the Capital and Construction department, and that the asset has been included in the operations and planned maintenance activity systems for the ActewAGL Distribution's assets.

Figure 3.9 also shows the progressive narrowing of cost estimates for medium and major projects as they move through the gating process. In general, projects included in the AMP (and this access arrangement proposal) have not yet been through a detailed feasibility estimate and are therefore forecast with a degree of certainty around ±50 per cent. These cost estimates are largely based on costs of like projects. In practice, the ±50 per cent cost estimation is a very conservative figure. The final costs of a project are more likely to skew upwards within this range than downwards as the project moves through the later gates. From the concept estimate stage (±50 per cent), projects move to feasibility estimate (±30 per cent), and finally to committed estimate (±10 per cent). The final costs therefore generally err to the higher side of initial estimates.

Figure 3.9 Capital approval processes for minor, medium and major projects



3.6 Capital expenditure deliverability

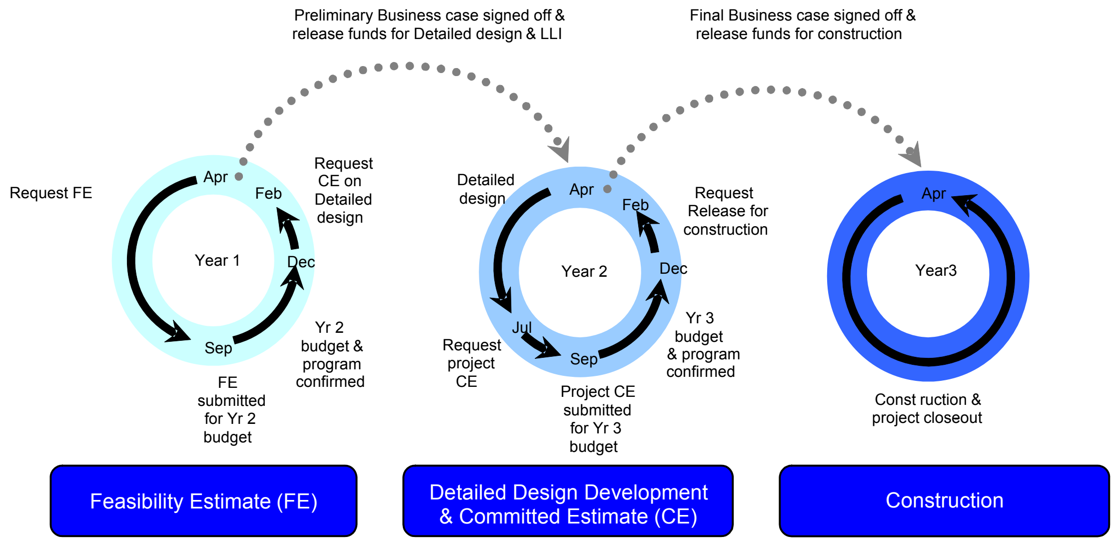
ActewAGL Distribution is aware that it will be competing with other Australian distribution businesses for resources and expertise to deliver its proposed capital and operating expenditure program. As outlined in chapter 6 of this access arrangement information, ActewAGL Distribution anticipates an increase in capital expenditure in the access arrangement period, largely due to the Hoskinstown to Fyshwick Loop, the Tuggeranong Primary Mains extension and PRS, and meter replacements.

ActewAGL Distribution's asset management contract (the DAMS Agreement) provides it with considerable certainty over the deliverability of its forecast capital program for the access arrangement period. JAM provides asset management services to a number of other network service providers. The ActewAGL Distribution gas network makes up just 10 per cent of assets managed by JAM. This means that the human resources needed to deliver projects for the ActewAGL Distribution network derive from a larger pool of resources including network planners, project managers and field staff. Resources for ActewAGL Distribution projects are secured from JAM via agreement over the AMP and annual Service Plan.

In addition, ActewAGL Distribution's planning process provides for the early identification of likely projects and significant scope for *ramping up* required resources. For example, the AMP includes forecasts of expected medium and major capital projects up to 6 years in the future. This allows projects to be identified and assessed as part of the normal asset management planning process, and for projects to be sequenced to manage resource allocations.

Major projects are also typically managed over a three year period, as shown in Figure 3.10. The first year typically involves a feasibility estimate and committed estimate detailed design. The second year involves a detailed designing process and resource allocation. The final year is the construction year. Therefore, the lead up to a major project can include 2 years of detailed planning and preparation that allows the allocation of appropriate resources. This is in addition to higher level project forecasting in the AMP which in some cases may have started 4 years prior to project construction.

Figure 3.10 JAM activity planning – major projects



4 Regulatory obligations and service standards

This chapter of the access arrangement information provides an overview of current and new and changing regulatory obligations that apply to ActewAGL Distribution, as well as relevant service performance for the gas network and service standard targets.

4.1 Introduction

Compliance with regulatory obligations is a substantial driver of the costs facing ActewAGL Distribution in the construction, operation and maintenance of its gas network. This section provides a high level description of energy specific regulatory obligations facing ActewAGL Distribution in its day-to-day business. These obligations are reflected in ActewAGL Distribution's plans and procedures, and demonstrated through activities and projects in the access arrangement period. This section also discusses new or changing obligations.

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. The details of regulatory requirements listed here are therefore referenced throughout this access arrangement information document and supporting information provided to the AER, where these obligations are specific drivers of expenditure.

4.2 Current regulatory obligations

4.2.1 Industry, technical and safety regulation

The key instruments that give ActewAGL Distribution the authority to operate the ACT, Queanbeyan and Palerang gas distribution network in the ACT and NSW are the *Utilities Act 2000 (ACT)* and the *Gas Supply Act 1996 (NSW).* These Acts require a gas distribution network operator to hold a licence or authorisation, to which detailed conditions are attached, including reporting requirements. Annual licence or authorisation fees or levies also apply under both instruments. In the ACT, a Utilities (Network Facilities) Tax (UNFT) also applies.

Under the powers of the *Utilities Act*, the ICRC has developed a number of Codes of Practice that apply to ActewAGL Distribution. These include:

- Consumer Protection Code;
- Gas Network Boundary Code; and
- Gas Network Capital Contributions Code.

A number of technical and safety codes are also in place, regulated by ACTPLA. These include:

- Gas General Metering Code; and
- Gas Safety and Operating Plan Code.

In NSW, regulation is largely undertaken through Regulations rather than Codes. Principle safety regulation is under the *Gas Supply (Safety and Network Management) Regulation 2008*, which covers:

- safety of gas networks;
- safety and operating plans for gas networks;
- standards for natural gas; and
- carrying out of gas fitting work.

This Regulation, as well as the *Safety and Operating Plan Code* currently in place in the ACT, requires gas distributors to develop and comply with relevant SAOPs, and comply with Australian Standards, in particular AS4645 and AS2885.

Cross county pipelines in NSW are regulated under the *Pipelines Act 1967 (NSW)*, which requires any person who wishes to construct and operate a pipeline to hold a licence. ActewAGL Distribution holds licence for the Trunk Main from Hoskinstown to the ACT border (Licence No. 29). The Act and licence include obligations for safe management of the pipeline and the easement it runs through.

In accordance with the *Gas Safety and Operating Plan Code 2000* (ACT), the distribution network SAOP must be reviewed on a regular basis. Under the *Gas Supply (Safety and Network Management) Regulation 2008 (NSW)* and AS2885.3, the licensed pipeline SAOP is to be approved, implemented and reviewed every two years if significant incremental change has occurred, or, in any event, when the scope of any single change is significant.

The relevant instruments require both SAOPs to be audited by a nominated auditor who is accepted by the relevant technical regulator. The auditor shall be competent and independent of the licence holder.

The audit certificate and report shall be lodged with:

- The Chief Executive of ACTPLA within 28 days of the end of the year (ACT);
- The Director-General DWE within 28 days after each anniversary of the date of the lodgement of the first SAOP or at another frequency approved by the Director-General for distribution networks (NSW); and
- The Director-General DWE within 28 days after each anniversary of the grant of the licence or at another frequency approved by the Director-General for licensed pipelines (NSW).

4.2.2 Access and market regulation

As a service provider for a regulated gas network, ActewAGL Distribution is subject to access regulation through the NGL and NGR. These national laws are applied in NSW and the ACT respectively through the *National Gas (NSW) Act 2008* and the *National Gas (ACT) Act 2008*. The NGL establishes the access regulation framework for third party access to natural gas pipeline services and elements of the broader natural gas market. The NGR have the force of law and govern the specific matters concerning access to natural gas pipeline services and elements of the broader natural gas market within the framework established by the NGL.

The regulatory framework sets up key obligations in the following areas:

- compliance with regulatory information powers of the regulator: the AER has the power to obtain general regulatory information and records from service providers and related providers;
- general obligations for provision of pipeline services by covered pipelines (with full regulation): the service provider must be a legal entity, submit an access arrangement for approval and must not hinder access to its pipeline;
- structural and operational separation (ring fencing): a gas pipeline Service Provider must not carry on a related business, must maintain specific accounts, must abide by confidentiality rules, ensure that none of its marketing staff are staff of an associate of the covered pipeline service provider that takes part in a related business or vice versa, and must not enter into an Associate Contract that either has an anti-competitive effect or is inconsistent with the competitive parity rule.

ActewAGL Distribution currently takes part in the gas retail market for its ACT and NSW network through the Gas Market Company (GMC). The gas market rules administered by the GMC facilitate full retail contestability in NSW and the ACT. These functions will shortly be transferred to the Australian Energy Market Operator (AEMO), as discussed in the following section.

4.3 New or changing obligations

4.3.1 National energy regulation

There have been a number of developments in national energy regulation through the MCE over the previous access arrangement period. Further reforms to national regulatory frameworks are expected in the access arrangement period. These are discussed below.

4.3.1.1 Introduction of new National Gas Law and National Gas Rules

Since the submission of the previous access arrangement, economic regulation has changed significantly. In July 2008 the NGL and NGR were introduced. These provisions replaced the former gas code.

While many aspects of the new law and rules continue obligations that were in place under the previous regime, there are some new regulatory obligations and powers for the AER. In particular, the new law and rules:

- Establish a new information regime whereby ActewAGL Distribution must comply with any *Regulatory Information Order* or *Regulatory Information Notice* that applies to it. The costs of complying with information requirements make up part of the legitimate costs of a service provider in complying with obligations and can be recovered in its revenue;

- Extend regulatory information powers to related providers. While not directly a cost on ActewAGL Distribution, in the event that the AER does issue an information instrument on a related provider to ActewAGL Distribution, it is expected that the costs incurred by the related provider will be passed through to ActewAGL Distribution through increased contract costs;
- Extend compliance monitoring and enforcement powers; and
- Establish new arrangements for greenfield developments and scope for light regulation of covered pipelines and networks.

A number of transitional provisions are relevant to this change from jurisdictional to national regulation, as discussed chapters 2 and 4 of this access arrangement information.

4.3.1.2 Transition to the Australian Energy Regulator

With the introduction of the new NGL and NGR, the AER became the responsible regulator for the ACT, Queanbeyan and Palerang gas network, transferring responsibility from the ICRC.

This access arrangement revision process is the first undertaken by the AER for a gas distribution business, and one of the first under the NGL and NGR. The AER has released a guideline to assist in interpreting the new arrangements. The new arrangements also impose a much tighter timetable on the AER for consideration of an access arrangement revision proposal.

The AER has released an annual compliance order applying to ActewAGL Distribution. The Order seeks information from ActewAGL Distribution on an annual basis on its compliance with various requirements under the NGL and NGR. These national information reporting and compliance requirements sit alongside a continuing monitoring and compliance role for the ICRC in respect of remaining jurisdictional areas of regulation, at least until the new NECF described below replaces the bulk of these arrangements. These dual regulatory compliance arrangements are expected to increase the compliance burden on ActewAGL Distribution, though ActewAGL Distribution notes the AER's intention to streamline regulatory reporting where possible to reduce overlapping or duplicative reporting requirements.[36]

4.3.1.3 Introduction of the new National Energy Customer Framework

As discussed in chapter 2, the MCE is currently developing a new national framework covering non-economic electricity and gas distribution and retail functions. The new framework seeks to establish nationally consistent arrangements across the electricity and gas sectors to protect small residential and business retail customers.

The first exposure draft of the new package proposes the following obligations on gas and electricity distributors:

[36] AER letter to ActewAGL, *ActewAGL's concern regarding overlapping or duplicative regulatory reporting*, 10 October 2008

- a deemed ‘standard distribution contract’ with all small end use customers coming into effect when customers first take supply from a supply point;
- scope for distributors to develop deemed large customer distribution contracts. In the absence of an approved alternative large customer contract, the deemed small customer contract will apply;
- an obligation to connect and provide distribution services to end use customers under deemed distribution contracts;
- an obligation to adopt mandatory minimum provisions when entering into a ‘gas service agreement’ with a retailer called ‘retail support clauses’. In respect of gas, these clauses can otherwise be read into existing access arrangements if not explicitly adopted in a separate gas service agreement; and
- new service definitions under the standard distribution contract and the retail services contract that create new services provided by distributors to both retailers and end use customers.

The new services regime is accompanied by a proposed liability regime to be contained within a distributor’s standard distribution contract and gas service agreement. The regime will cover:

- quality of supply;
- exclusion of implied terms and liabilities;
- interruptions and curtailments; and
- force majeure.

The MCE Standing Committee of Officials (SCO) has indicated that while there will be similar statutory immunities for electricity and gas, there will be no liability cap for negligence or bad faith. This opens up a new exposure for many distributors and is materially different to the service provision and liability regime currently in place for ActewAGL Distribution in NSW and the ACT.

The first exposure draft also includes significant new roles for the AER under the framework. The AER will:

- be bound by the retail support contractual clauses in approving access arrangements;
- approve any proposed standard distribution contracts for large customers;
- have a general enforcement role similar to that in the NGL but extended to include enforceable undertakings and remedies for non-compliance; and
- have extended information gathering powers to cover the scope of new legislation, including AER powers to require information for compliance and performance reporting.

The proposed new national framework, if introduced as currently formulated, represents a significant increase in the scope and intrusiveness of regulation of the gas sector from that currently experienced by ActewAGL Distribution in operating in NSW and the ACT.

While focused on the provision of services to customers and consumer protection, the proposed new framework also represents a significant shift in access regulation in the gas sector. The current gas access framework establishes an access arrangement covering gas haulage services provided to retailers and large customers. The proposed new framework effectively changes this service provision, such that aspects of the distribution service provided to retailers under the access arrangement are also provided to end use customers under the distribution contract. Explanatory material released with the first exposure draft does not address how this inconsistency between the new customer framework and the access framework will be addressed. The MCE SCO has noted, however, that consequential amendments to the existing NGL may be required to implement the NECF.[37]

The explanatory material of the framework also discussed at a high level the possibility of jurisdictionally-based implementation with staggered timetables and the potential for some aspects of the framework to be implemented ahead of others.[38] ActewAGL Distribution considers that managing the change to the new framework through transitional arrangements that lock in or grandfather current arrangements would be a superior approach to introducing and implementing the framework within an access arrangement period. Appropriate transitional arrangements would see the new framework apply to a gas distribution business only at the start of its next access arrangement. Since no decision has yet been made on transitional arrangements, nor any details provided or recognition given to this issue in the exposure draft, ActewAGL Distribution must note the possibility that the new arrangements could apply during this access arrangement period.

Uncertainties over the details of the final framework, the timing of the new arrangements, and transitional provisions that may apply, make it difficult to accurately forecast the impact and scope of changes on this access arrangement period. Given the potential for the NECF to lead to significant changes to service provision arrangements during this access arrangement period, especially given the NGL and NGR changes, ActewAGL Distribution considers it necessary to put in place specific arrangements to address this new framework in the access arrangement.

ActewAGL Distribution therefore proposed a specific cost pass through event, to manage additional costs associated with the introduction of the scheme. This proposed pass through event is discussed at section 11 of this access arrangement information.

Some of the changes proposed under the NECF, however, may not be suitable for cost pass through, as they relate not to direct changes in costs, but to the scope of regulation and services provided. These include changes in service definitions that may require changes to definitions of references services in the access arrangement. ActewAGL Distribution notes that the implementation of the scheme during the access arrangement period may mean that ActewAGL Distribution will need to submit to the AER a proposal to vary the access arrangement under Rule 65. The extent to which this may be necessary,

[37] MCE SCO, *Explanatory Material*, April 2009, p 9
[38] MCE SCO, *Explanatory Material*, April 2009, p 2

however, cannot be known before the final framework has been decided, including transitional arrangements.

Varying the access arrangement would be an inferior outcome to appropriate transitional arrangements, or using the pass through mechanism discussed above, however it may be necessary if the scope of services (and the NGL) changes significantly through the introduction of the framework.

4.3.1.4 Introduction of the new National Gas Connections Framework

The *Australian Energy Market Agreement* includes an agreement to develop new national connection and capital contribution requirements for the electricity and gas sectors.[39] Work on the National Gas Connections Framework (NGCF) is still in its infancy, however, the MCE SCO have indicated that the gas connections framework will be consistent, where possible, with the electricity connections framework.[40] The work undertaken so far on the electricity connections framework therefore provides an indication of the expected approach for gas.

In December 2008 as part of the development of the NECF, the MCE SCO released a policy response paper dealing with a national *electricity* connection framework. The policy objectives for the electricity connection framework include the following, which appear to have equal application to gas connections:

- To provide a national framework to harmonise network connections arrangements between jurisdictions;
- To integrate regulation of non-price elements of connections with the AER's economic distribution regulation powers; and
- To provide a framework for negotiation between users of all sizes and distributors where appropriate, and to make this process as user-friendly as possible while delivering certainty to all parties.[41]

The SCO's proposed model for electricity connections includes a set of standard connection contracts. The AER will have the role of approving a common standard connection definition (and associated technical requirements) and the common standard connection contract, as well as additional standard connection contracts for each distribution network. The AER will apply a 'fair and reasonable' test to the definitions.

The SCO's paper makes it clear that the connections frameworks for both gas and electricity are intended to integrate with the NECF in the second exposure draft of the NECF package.[42] There is considerable potential for the new NGCF to impose additional costs on ActewAGL Distribution by requiring new contracting arrangements and a new direct relationship with customers in respect of connections (which are currently managed

[39] Amended Australian Energy Market Agreement, June 2006, Annexure 2, p 1
[40] MCE SCO, *Electricity Distribution Network Planning and Connection: A national framework for electricity distribution networks: Policy Response*, 15 December 2000, p 17
[41] MCE SCO, *Electricity Distribution Network Planning and Connection: A national framework for electricity distribution networks: Policy Response*, 15 December 2000, p 10
[42] MCE SCO, *Electricity Distribution Network Planning and Connection: A national framework for electricity distribution networks: Policy Response*, 15 December 2000, p 17

through retailers). The scope of the proposed changes, their timing, and their cost, however, are very difficult to forecast. ActewAGL Distribution proposes that changes be managed through a specific cost pass through event, to manage additional costs associated with the introduction of the scheme. This proposed pass through event is discussed at section 11 of this access arrangement information.

4.3.1.5 Introduction of the Australian Energy Market Operator

The AEMO will start operation on 1 July 2009. The AEMO takes over responsibilities for the National Electricity Market Management Company (NEMMCO), Victorian Energy Networks Company, the GMC and Retail Energy Market Company.

There are only limited details currently available on how the transfer to responsibilities of the GMC to AEMO will impact on costs in the access arrangement period. The AEMO will take over responsibility for the operation of the NSW and ACT gas market functions from GMC, in particular the retail market operations. Current gas market rules administered by the GMC will be transferred to AEMO as retail procedures made under the NGR. Provisions for AEMO to amend these procedures will be included in the NGR, but will not prescribe a process.

The AEMO also acquires new powers and functions that are currently not available to the GMC. In particular, the AEMO has information gathering powers in respect of relevant functions, which include the development of a gas statement of opportunities. These powers are very similar to those available to the AER for economic regulatory functions and powers under the NGL, and, similar to these powers, there is significant scope for the implementation of these powers to lead to additional costs on ActewAGL Distribution.

In addition, the cost recovery framework for the AEMO in respect its functions are yet to be finalised. Explanatory Material released with the AEMO legislation exposure drafts suggests that the cost recovery framework for existing market operators is intended to be retained for a minimum of two years, with a review no later than three years after the AEMO is established.[43] The new AEMO fee structure will be set in accordance with the current NEMMCO cost recovery model and include principles that there should not be cost subsidisation between AEMO's different functions. It is therefore not anticipated that ActewAGL Distribution's fees paid to the AEMO will be materially different to those paid to the GMC for the first 2 years of the access arrangement.

Given the AEMO's expanded role compared to that of the GMC, it is expected, however, that AEMO market participant costs will rise significantly following the fee *transitional* period. This change is reflected in the operating expenditure forecasts through a step change in fees associated with gas market management.

ActewAGL Distribution has also included an adjustment factor in its annual reference tariff variation formula to account for differences between forecast amounts for AEMO fees and those actually paid. This is to ensure that ActewAGL Distribution is not exposed to forecasting risks associated with uncontrollable, externally imposed charges. Further

[43] Explanatory Material, AEMO exposure drafts, p 9

details of this adjustment factor are discussed in section 11 as part of the proposed annual tariff variation mechanism.

4.3.1.6 Gas Short Term Trading Market

The STTM is an initiative of the MCE to develop markets for gas at trading hubs. The initial hubs are to be the Sydney-Wollongong-Newcastle trunk main system owned by Jemena Gas Networks (JGN) supplied by the MSP and the EGP, and the Adelaide hub supplied by the Moomba to Adelaide Pipeline System and the SEAGas Pipeline. The STTM is expected to come into operation on 1 July 2010. Details of the market are still being finalised.

The ActewAGL Distribution network is not part of the Sydney hub and so will not be directly impacted by the STTM at its inception. There will, however, be secondary impacts on the ActewAGL Distribution network and on the costs of management services arising from its location relative to the Sydney/Wollongong/Newcastle network.

Increased trading of gas between the MSP and the EGP as a result of the STTM is expected to make network management, in particular the management of pressure at the Watson and Hoskinstown receipt points, more difficult. It is also expected to increase the cost of balancing gas where there is a supply shortage and make it more difficult to secure long term contractual arrangements for balancing gas as marginal gas becomes more valuable under the STTM. There is potential for these two factors to also lead to an increase in market shortfall events, and the need for more intervention in the wholesale market to maintain supply into the ACT. There are expected to be additional costs associated with managing these incidents. The costs of these changes are reflected in the operating expenditure forecasts through a step change in costs associated with market costs, unaccounted for gas and balancing gas.

As a result of the contracting arrangements described in chapter 3, ActewAGL Distribution utilises systems (known as CABS) and personnel through JAM to manage its current gas balancing needs.[44] As balancing arrangements for JGN's Sydney network will be transferred to the AEMO and managed under the STTM, ActewAGL Distribution will no longer share the bulk of these facilities with another service provider. This is expected to lead to an increase in charges under the DAMS Agreement for these services.

In addition, with gas balancing arrangements for the Sydney hub being managed through the STTM, policy advice and market management services undertaken by JAM in respect of gas balancing under the gas market rules will no longer be shared with another service provider. This is also expected to lead to an increase in charges under the DAMS Agreement for these services. Both of these changes are reflected in the operating expenditure forecasts through a step change in costs associated with the introduction of the STTM.

[44] Gas balancing is the process of managing nominations (the amount a supplier states is being injected into the system on their behalf) and withdrawals (the amount that customers extract from the network from use).

In addition, there is a possibility that Canberra will become a trading hub during the access arrangement period.[45] This would see a significant change in the approach to balancing gas and in the operation and management of the network between the Watson and Hoskinstown receipt points. ActewAGL Distribution may also be required to participate in the STTM to secure balancing gas. In the event that the Canberra network becomes a hub in the STTM during the access arrangement period, ActewAGL Distribution proposes that the impacts of changes be managed through a specific STTM pass through event discussed at section 11.3.1.1 of this access arrangement information.

4.3.2 Jurisdictional energy regulation

4.3.2.1 Consumer Protection Code

The ICRC has recently released amendments to the Consumer Protection Code, which will come into effect on 1 July 2009. Amendments to the Code mainly clarify existing provisions, however one change relevant to the distribution network is a change to the minimum service standards applying under the Code in respect of customer complaints.

The revised Code now requires that a customer complaint must be acknowledged “immediately or as soon as practicable” upon receiving the complaint. This replaces the previous timeframe of 10 business days to acknowledge a complaint. A minimum rebate amount of $20 applies to this requirement.

The ICRC has made this change to more closely align the Code with the requirements of the relevant Australian Standard, consistent with the existing requirement in the Code that practices and procedures for complaints handling comply with Australian Standards. The ICRC has stated that there is an expectation in the formulation of “immediately or as soon as practicable”, that some complaints can and should be acknowledged immediately, while other acknowledgements may take longer.[46]

Given the small number of customer complaints received by ActewAGL Distribution and the number of rebate payments, no change in forecasting operating expenditure is sought for this change.

4.3.2.2 Utilities (Network Facilities) Tax

From January 2007, ActewAGL Distribution has been required to pay a yearly UNFT to the ACT Government, under the *Utilities (network Facilities Tax) Act 2006* (ACT). The tax rate is set by the responsible Minister under the *Tax Administration Act 1999* (ACT), and the final tax amount is calculated as the determined rate multiplied by route length. As this tax was introduced during the earlier access arrangement period, tax amounts have been recovered as a pass through in the earlier access arrangement period.

There is some potential volatility in these tax amounts, as the rate is set by the ACT Government each year and is therefore subject to change. ActewAGL Distribution has included a forecast of the expected costs of this tax in its forecast operating expenditure,

[45] ActewAGL Distribution expects that this would be a decision by the ACT Government and is expected to require new legislative instruments or changes to existing instruments.
[46] ACT *Utilities (Consumer Protection Code) Determination 2009 Disallowable Instrument DI2009-75 made under the Utilities Act 2000, s 59 (Determined codes) and s 63 (Public access): Explanatory Statement*, p 5

based on the growth in UNFT revenue assumed by the ACT Government in the 2009/10 budget forward estimates.

ActewAGL Distribution is has also included an adjustment factor in its tariff variation mechanism to account for differences between forecast amounts for the UNFT and those amounts actually paid. Further details of this adjustment factor are discussed at section 11 of this access arrangement information.

4.3.3 Technical and safety regulation

Changes in technical regulatory requirements, particularly the review of key Australian Standards AS4645 and AS2885, have resulted in changed technical regulatory obligations in the previous access arrangement period that need to be reflected is this access arrangement period. In addition, new environmental and climate change legislation will have a significant impact on the gas network demand and costs. These areas of new and changing regulatory requirements are discussed below.

4.3.3.1 New Work Safety Act 2008 (ACT)

The ACT Government has introduced the *Work Safety Act 2008* (ACT) to replace the *Occupational Health and Safety Act 1989* (ACT). The new Act introduces new obligations and broadens the scope of obligations on ActewAGL Distribution (and JAM for its workers in the ACT) in respect of safety matters.

As a result of the new Act, ActewAGL Distribution will incur significant transitional costs in auditing and reviewing current corporate safety policies and procedures to ensure compliance in the new arrangements that will come into effect on 1 October 2009. For example, ActewAGL Distribution must review and audit its current Life Guard policies, train staff, engage consultants and establish consultative committees as required under the Act. ActewAGL Distribution will also incur additional ongoing compliance costs as a result of increased obligations under the new Act.

The transitional costs occur in the earlier access arrangement period, and are included in corporate expenditure for 2008/09 and 2009/10. ActewAGL Distribution has not included any step change for the ongoing additional costs of the new Act in its forecast corporate expenditure, and instead expects to incorporate the additional obligations through indirect efficiency gains in the organisation.

4.3.3.2 Changes to AS4645 – Gas Distribution Networks

Australian Standard S4645 provides for the protection of the general public, gas distribution network operating personnel and the environment, and to ensure safe operation of the gas distribution network that reticulates gas to consumers. In particular, the purpose of this Standard is to:

- provide performance-based requirements for gas distribution network safety, defining important principles during the lifecycle of gas distribution networks;
- provide prescriptive, deemed to comply, means of compliance in support of some of those requirements; and

- allow for alternative means of compliance that may be also acceptable provided the required safety outcomes can be demonstrated.

AS4645 comprises of a number of parts. One particular change, which has arisen out of its revision process, is the introduction of formal safety assessments. An assessment is a process to assess the safety of assets with a defined approach which requires a series of workshops. This is a new regulatory requirement that is reflected in the operating expenditure forecasts through a step change in costs.

4.3.3.3 Changes to AS2885 - SAA Pipeline Code

The AS2885 suite of Standards (the Standard) establishes requirements for the safe design, construction, inspection, testing, operation and maintenance of a land or submarine pipelines constructed from steel pipe, and designed to transport gas or liquid petroleum. These requirements are necessary for the protection of the general public, operating personnel, and the environment, as well as the protection of the pipeline against accidental damage. AS2885 is recognised as one of the world's leading edge standards achieving maximum community safety at the lowest sustainable cost.

The various parts of AS2885 are under review on a regular cycle. Part 1 (AS2885.1) of the Standard had a major review, which in 2007 resulted in the release of the most recent revision. Significant changes have been made to the standard that impact on the operation of pipelines. Most relevant to the ActewAGL Distribution gas network are two new requirements: for safety management studies and for facility integrity reviews.

The requirement for *safety management studies* requires operators of high pressure gas pipeline infrastructure to run regular workshops each year to ensure the appropriate management of relevant pipelines.

The requirement for *facility integrity reviews* involves periodic review of trunk main and primary main high pressure facilities as part of integrity management. The reviews must be undertaken at least every 5 years. There are typically two kinds of review:

- High Pressure Facilities Integrity Review – identifies safety and integrity issues with the high-pressure facilities for regulatory and technical compliance; and
- High Pressure Facilities Record Management Review – addresses the record management system and its requirements.

The High Pressure Facilities Integrity Review involves assessing the current pipeline operation in respect of:

- HAZOP study;
- Validation of earthing;
- Risk assessment;
- Hazardous area classification; and
- OH&S assessment.

The High Pressure Facilities Record Management Review follows on from the High Pressure Facilities Integrity Review. It focuses on bringing documentation up to date in accordance with the latest AS2885 requirements.

These new regulatory requirements are reflected in the operating expenditure forecasts through a step change in costs.

4.3.3.4 Gas Fitting Rules

Currently there are no gas fitting rules (similar to the electricity service and installation rules in electricity) in place in the ACT. Some guidance is provided through an Australian Standard, though this standard is at a relatively high level.

The ACT technical regulator, ACTPLA, has informed ActewAGL Distribution that it considers that the Australian Standard does not provide sufficient detail regarding appropriate meter sets and inlet services and therefore intends to introduce gas fitting rules in these areas. It has asked ActewAGL Distribution to develop these rules.

ActewAGL Distribution intends to propose similar gas fitting rules to those currently in operation on the JGN (Sydney) network. If this proposal is accepted, it is not expected that this will lead to a material increase in costs, as it will formalise the existing approach already taken by ActewAGL Distribution as ActewAGL Distribution already applies the more detailed provisions in the JGN gas fitting rules through its contract with JAM. In the event that alternative gas fitting rules are adopted in the ACT, additional costs may need to be addressed through cost pass through mechanisms discussed in section 11 of this access arrangement information.

4.3.4 Environmental regulation

4.3.4.1 National climate change legislation

The Australian Government has announced the introduction of a national CPRS by 2011 as a key component of its climate change policy. The Government's white paper, qualified by subsequent statements,[47] proposes that carbon trading would commence from 2011 with the aim of reductions in Australia's carbon emissions of between 5 and 25 per cent by 2040.

While many details are still to be determined, it is known that the CPRS will require businesses that emit more than 25 000 tonnes of carbon dioxide equivalent gases (CO_2-e) as part of their industrial processes to pay for the right to do so. Businesses will demonstrate that they have complied with this requirement by buying and surrendering permits, and will be subject to periodic audits and reporting under the NGERS. If businesses do not surrender permits equivalent to their emissions they may be subject to a financial penalty.

The CPRS is expected to affect gas distribution businesses by imposing a carbon price on goods and services that the business purchases. For ActewAGL Distribution, this will

[47] Prime Minister of Australia Media Release, "Carbon Pollution Reduction Scheme: Support in Managing the Impact of the Global Recession", 4 May 2009.

directly affect the cost of gas purchased for UAG (to cover fugitive emissions) and system gas, and indirectly influence the costs of materials and transport. It is also expected to affect demand for gas. These factors are discussed below.

Unaccounted for Gas and fugitive emissions

Unaccounted-for Gas (UAG) is defined as the difference between the amount of gas injected into a system and the amount of gas extracted from the system through consumer meter sets. A level of UAG is characteristic of all gas networks.

Where there are UAG losses from the system, they may consist of leakage through mains, services, meter sets and other ancillary equipment. A distributor's operational activities may also contribute when gas is discharged to the atmosphere during construction work or when gas mains are purged.

It is important to note, however, that UAG reported does not equate to fugitive emissions. Metering inaccuracy and especially inoperative meters are larger contributors to reported UAG than those determinates listed above.

ActewAGL's Distribution's UAG outcomes and proposals are discussed at sections 9.1.3.3 and 9.2.3.3, respectively, of this access arrangement information.

The NGL allows for efficient costs of regulatory obligations, which ActewAGL would expect to include the costs of reporting and permit purchase, to be passed through to customers. Considerable uncertainty remains, however, regarding the method of estimation of fugitive emissions, and the expected administrative costs of the emission reporting regime.

Carbon permit costs and administrative costs arising from the new NGERS are proposed to be addressed through a specific pass through event, discussed further in tariff variation mechanisms.

Impacts on input costs and prices

Input costs for both operations and maintenance and capital will increase due to the impact of the CPRS on transport and materials. Relevant escalators have been included in ActewAGL Distribution's forecast for capital expenditure, discussed in chapter 6 of this access arrangement information.

Capital costs also rise as the result of having to build larger infrastructure to cope with peakier network loads. Peakier loads are the result of expected higher take up of more energy efficient instantaneous natural gas and gas-boosted solar water heaters. Both of these appliances typically cause greater peaks in gas consumption (while using less gas overall) than less energy-efficient storage water heaters. These peakier loads drive capacity development expenditure, as discussed in chapter 6.

Impacts on demand

The degree to which gas is competitive with electricity will be influenced by comparative costs of each fuel source; themselves affected by increased carbon pollution costs incurred in capital and operating costs. Demand will also be affected by the trends toward greater efficiency of domestic appliances, leading to lower average demand per household. Further detail on national energy efficiency initiatives and obligations is outlined in chapter 5 of this access arrangement information.

ActewAGL Distribution's demand forecast incorporates the effect of the CPRS on gas demand. The resultant demand forecast is set out in section 5.2 of this access arrangement information.

4.3.4.2 ACT climate change policies

There are also a number of ACT specific policy developments that impact on ActewAGL Distribution during the access arrangement period. These include the:

- *Weathering the Change* strategy; and
- Inquiry into ACT Greenhouse Gas Reduction Targets.

The ACT Government has implemented a climate change strategy in the ACT called *Weathering the Change*.[48] This provides an overview of climate change science, predicted impacts on the ACT, and the ACT's vision and direction for responding to climate change for the period 2007 to 2025. *Weathering the Change* consists of four Action Plans over the relevant period, with the initial aim of limiting 2025 emissions to 2000 levels.

The current Action Plan 2007 – 2011 outlines 43 items to be implemented before 2011. Relevant items to ActewAGL Distribution include the development of an energy policy, national emissions trading and reporting and pursuing energy efficiency ratings for all buildings in the ACT. There is potential for a number of changes to legislation and policy to result from the actions under this current Action Plan, and the second Action Plan which has not yet been developed but is intended to operate from 2012-16.

In addition to the ACT Government climate change strategy, the Standing Committee on Climate Change, Environment and Water in the ACT Legislative Assembly is currently conducting an inquiry into ACT Greenhouse Gas Reduction Targets. The inquiry covers:

- appropriate targets and associated dates for greenhouse gas emissions peaking and reduction;
- appropriate monitoring, reporting and review processes associated with the targets; and
- other issues associated with greenhouse gas reduction including:
    - existing, and the need for additional, programs in ACT;
    - future energy supplies in ACT;
    - climate change impacts on sustainability of existing ecological communities;
    - social equity and economic issues, costs and opportunities;

[48] Department of the Environment, Climate Change, Energy and Water, http://www.environment.act.gov.au/climate_change/weathering_the_change, accessed online 13 May 2009.

- relationship between these targets and policy and nationally implemented targets and policy;
- acceptability of local and offshore offsets; and
- the adequacy of existing data collection and methodology of establishing a baseline year of 1990 or 2000 and for future monitoring and reporting purposes.

The Standing Committee is required to report back on these issues on 30 July 2009.[49] Therefore, the outcome of the inquiry and any consequent changes to ACT legislation will potentially impact ActewAGL Distribution during the access arrangement. As the inquiry has not yet reached conclusions, it is unclear as to what changes may occur. Associated costs can therefore not be quantified.

ActewAGL Distribution proposes that potential ACT climate change obligations arising from these policy processes be addressed under the proposed Carbon Pollution Reduction Scheme pass through event or the Regulatory change pass through event discussed later in this access arrangement information.

4.4 Service standards

ActewAGL Distribution must comply with reporting obligations and some minimum performance standards with respect to its gas network. While there are standards in place for customer service parameters such as reliability, ActewAGL Distribution has established a number of targets for service performance which it includes in its annual report, as well as in the DAMS Agreement as service standard outcomes under the contract with JAM.

These targets reflect ActewAGL Distribution’s understanding of customer preferences in respect of key service dimensions, through the maintenance of service performance at established levels, as indicated in the ActewAGL Distribution willingness to pay study discussed below.

4.4.1 Willingness to pay

Prior to 2004, the ICRC and ActewAGL Distribution had limited formal research based information on whether customers considered current service levels appropriate, or on the marginal value customers place on increases or decreases in the levels of various aspects of service quality.

To better understand these issues, ActewAGL Distribution commissioned NERA Economic Consulting (NERA) in 2003 to establish customers’ marginal willingness to pay (WTP) for a range of utility service quality dimensions, including services provided through the gas network. NERA used a stated preference choice modelling survey to reveal customer preferences, simulating a market environment by providing customers with choices

[49] ACT Legislative Assembly, ACT Greenhouse Gas Reduction Targets Standing Committee Reference, 11 December 2008.

between various service quality and price scenarios. The study represents world leading research into customer preferences and WTP.

A key finding is that ActewAGL Distribution customers rate extremely highly both the standard of their gas supply and ActewAGL Distribution as a gas supplier, with 98 per cent of customers rating ActewAGL Distribution's gas supply as 'good' or better. In relation to gas service reliability, as measured by the length and duration of outages, ActewAGL Distribution's service level is near the optimum. NERA showed that customers prefer the current price-service mix to a doubling of outage frequency and duration with a 3 per cent price discount. The current price-service mix is also preferred to a halving of outage frequency and duration with a 3 per cent price premium.

The WTP survey found that gas was rated as the most highly reliable of the services provided by ActewAGL Distribution. There is a seasonal effect with gas customers willing to pay more to avoid outages in winter than in summer. This reflects the fact that gas is primarily used for space heating in the ACT. However, a significant proportion of customers use gas all year round for cooking (56 per cent) and hot water (50 per cent).

Evidence from the WTP study suggests that ActewAGL Distribution's current mix of service reliability and price is near the optimum. ActewAGL Distribution has therefore decided to maintain current targets for service reliability in the access arrangement period.

4.4.2 Key obligations and reporting

4.4.2.1 Consumer Protection Code

The ACT *Consumer Protection Code* applies to both retail and distribution businesses in the electricity and gas sectors, and contains both common and specific obligations. Schedule 1 of the Consumer Protection Code sets out minimum service standards applying to the gas distribution network, as well as rebates to be paid in the event of non-compliance. These standards and rebate amounts are listed in Table 4.1.

Table 4.1 Consumer Protection Code minimum service standards and rebates

Subject of Standard	Service standard required	Rebate payable for failure to meet standard
1. Customer Connection Times	If a Customer's Installation is: (a) physically connected to the electricity Network, the gas Network, the water Network or the sewerage Network; and (b) a Customer is entitled to supply of the relevant Utility Service or Services, a Utility must provide those services: (c) on the same day as the request is made if the request is made before 2:00pm; or (d) by the end of the next Business Day if a request is made after 2:00pm, otherwise, on a day agreed between the Customer and the Utility.	For each day after the date the Utility Service(s) should have been provided until those services are provided, the Customer may apply for a rebate of $60 to a maximum of $300. (If the Utility Service(s) are not provided within 5 days of the request, the Customer may restate their request to the Utility. For the purposes of this standard, a restated request will constitute a new request.)
2. Responding to Complaints	A Utility, upon receiving a Complaint from a Customer or Consumer, must: (a) acknowledge the Complaint immediately or as soon as practicable; and (b) respond to the Complaint within 20 Business Days.	If a Utility fails to meet the requirements of Standard 3(a) or 3(b), the Complainant may apply for a rebate of $20.
3. Response time to notification of problem or concern	A Utility notified of a problem or concern with the Utility's Network must: (a) if the notification relates to damage to, or a fault or problem with, the Utility's Network which is likely to affect public health, or is causing, or has the potential to cause, substantial damage or harm to a Person or property, respond as soon as practicable and in any event within six hours; or (b) in all other cases, respond within 48 hours; and (c) resolve the problem or concern within the time specified in the response.	If notification is from a Customer or a Consumer, and relates to a problem or concern that affects the Premises of the Customer or Consumer, that Customer or Consumer may apply for a rebate of: $60 for each day after the day on which the response should have been provided, until that response is provided, to a maximum of $300. (If a response is not provided within 5 Business Days of the request, the Customer may restate their notification to the Utility. For the purposes of this standard, a restated notification will constitute a new notification.) $60 for each problem or concern that is not resolved within the time specified in the response.

Subject of Standard	Service standard required	Rebate payable for failure to meet standard
4. Planned Interruptions to Utility services (applies only to Gas and Electricity Distributors and Water and Sewerage Utilities)	1) A Utility must give at least two Business Days notice of a Planned Interruption to a Utility Service to each Premises that will be affected by the interruption. 2) The notice must: (a) specify the reason for the interruption and the expected date, time and reasonably anticipated duration of the interruption; and (b) provide either: i. a business hours telephone number for inquiries; or ii. a 24-hour telephone number for inquiries. 3) A Utility undertaking a Planned Interruption to a Utility Service must take all steps that are reasonable and practicable to ensure that the duration of the interruption: (a) does not exceed the expected duration set out in a notice given under clause 19.2(1); and (b) in any event, does not exceed 12 hours.	For each affected Premises supplied under a Customer Contract, the Customer or Consumer may apply for a rebate of: $50 if the required notice of the interruption is not given. $50 if supply is not restored within the time specified in the notice, which must not exceed 12 hours.
5. Unplanned Interruptions to Utility services (applies only to Gas and Electricity Distributors and Water and Sewerage Utilities)	When an Unplanned Interruption occurs, a Utility must take all steps that are reasonable and practicable to restore the supply of the relevant Utility Service to affected Premises as soon as possible and, in any event, within 12 hours.	For each affected Premises supplied under a Customer Contract, the Customer or Consumer may apply for a rebate of $20 if supply is not restored within 12 hours.

Source: Consumer Protection Code: July 2009, Schedule 1

ActewAGL Distribution reports on its performance against these minimum service standards, as well as rebate amounts paid to customers, in its annual compliance report to the ICRC. In the 2007/08, ActewAGL Distribution reported no rebates for failing to meet service standards were paid to customers. ActewAGL Distribution notes that the costs of any rebates that are required are passed directly through to JAM as part of its incentives under the DAMS Agreement to ensure appropriate service delivery to customers.

It is expected that this annual reporting requirement will continue during the access arrangement period as the *Australian Energy Market Agreement* retains network service reliability standards as state and territory functions.[50]

4.4.2.2 ICRC reporting

In addition to the minimum rebate levels, ActewAGL Distribution reports to the ICRC on a number of reliability parameters. These include the frequency and duration of outages on the gas network. Performance against these parameters, expressed as a System Average Interruption Duration Index (SAIDI) and a System Average Interruption Frequency Index (SAIFI) is set in Table 4.2. These SAIDI and SAIFI measures show network reliability performance that is under ActewAGL Distribution's control.

There are no externally set targets for performance against these parameters. ActewAGL Distribution does, however, set targets for performance against a number of measures in the DAMS Agreement, some of which it included in its annual reporting, as discussed below.

Table 4.2 ActewAGL Distribution gas network reliability performance against targets[51]

Parameter	2004/05	2005/06	2006/07	2007/08	2008/09^	Target
SAIDI	0.30	0.37	0.41	0.30	0.26	NA
SAIFI*	1.24	1.51	1.35	1.24	0.93	<10

^ SAIDI and SAIFI values for 2008/09 are 12 month values up to 31 May 2009. All other values are for the relevant financial year.

* SAIFI is expressed as a frequency per 1000 customers to avoid a large number of decimal points.

Source: ActewAGL Gas Network Performance Benchmark Study

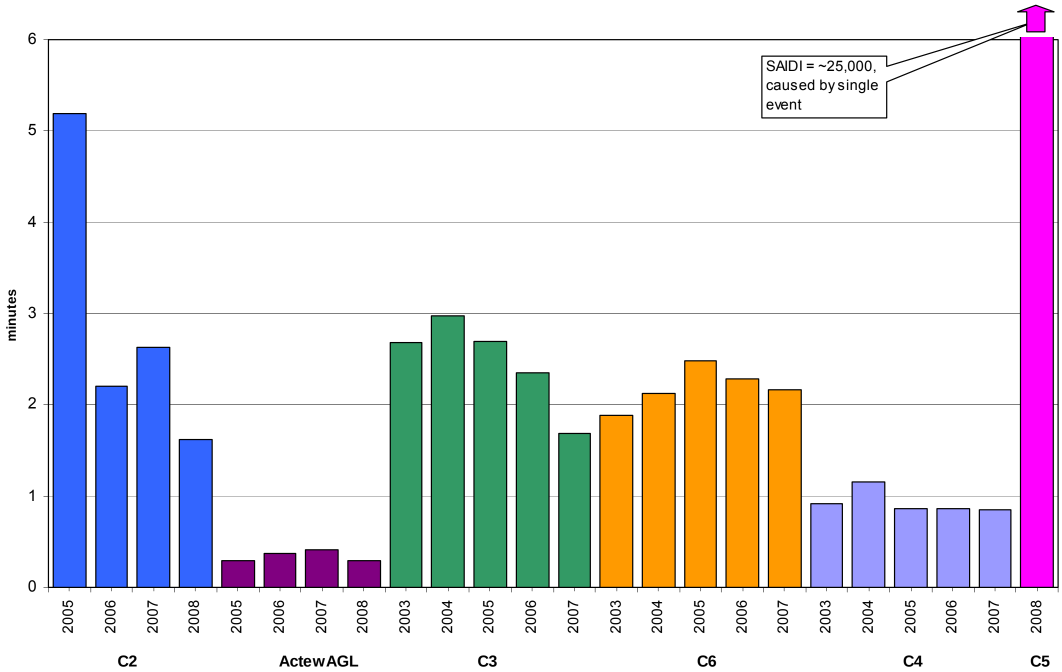
ActewAGL Distribution's performance against these measures is excellent and meets the service expectations of customers as confirmed by the WTP study. ActewAGL Distribution's reliability performance is also assisted by dual-sided street reticulation network architecture in the ACT. This means that in almost all cases customer sites can be back fed if there is a break in the main (for example a third party hit). This means that customers adjacent to an incident in most cases will retain supply.

Comparative performance is shown in the following graphs, which benchmark ActewAGL Distribution's SAIDI and SAIFI performance against other Australian gas distributors. Figure 4.1 shows ActewAGL Distribution's historic SAIDI performance against 5 other distributors. The performance benchmarking study is included at attachment F to this access arrangement information.

[50] Amended Australian Energy Market Agreement, June 2006, Annexure 2, p 2

[51] The SAIFI values reported in this table and in benchmarking below are slightly different to those reported by ActewAGL in its 2008 annual report. The difference results from a change in business rule for calculating these values that means the new values more accurately reflect ActewAGL Distribution's performance.

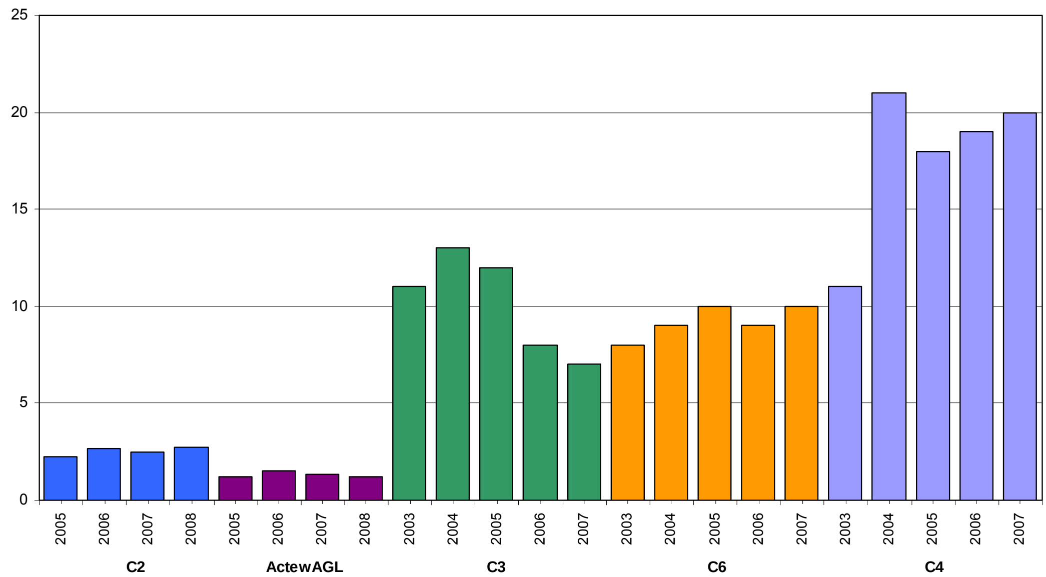
Figure 4.1 Average minutes off supply/customer (SAIDI) unplanned outages, all customers



Source: ActewAGL Gas Network Performance Benchmark Study

Figure 4.2 shows ActewAGL Distribution's historic SAIFI performance against 4 other distributors.

Figure 4.2 ActewAGL Distribution's average number of unplanned interruptions (SAIFI) per 1000 customers

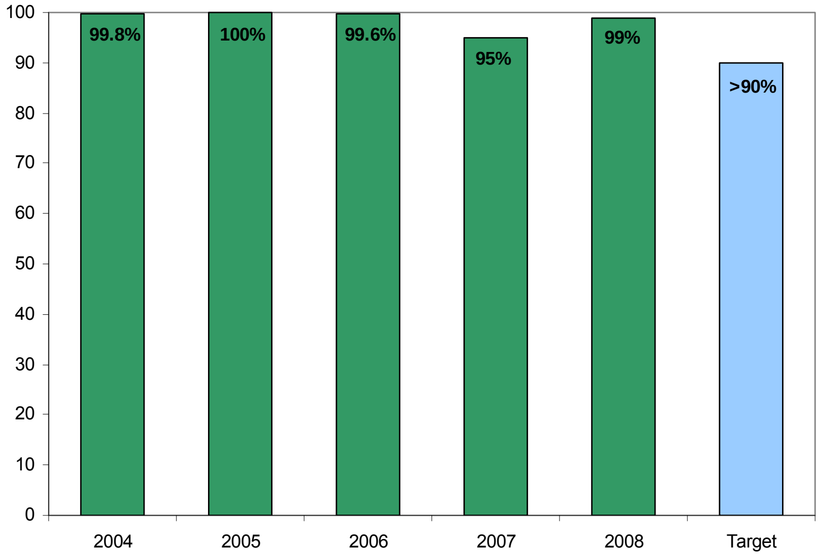


Source: ActewAGL Gas Network Performance Benchmark Study

4.4.2.3 ActewAGL reporting

ActewAGL Distribution also includes some aspects of gas network performance in its annual report, benchmarked against ActewAGL Distribution set targets. These parameters are SAIFI and supply restoration times. SAIFI performance is outlined above. Gas restoration time data is set out in Figure 4.3. ActewAGL Distribution publicly reports this data as it is of high interest to customers in terms of supply reliability and performance. The performance targets are also relatively challenging, particularly the restoration of gas supply within 4 hour contractual target placed on JAM.

Figure 4.3 ActewAGL Distribution's gas disruptions – percentage restored within four hours



4.4.2.4 Drivers of reliability performance

As shown above, ActewAGL Distribution's comparative reliability performance and performance against targets is very good. Benchmark information shows, however, that reliability performance, particularly SAIDI, can be highly volatile. This is because performance can be affected by single high impact events that affect a large number of customers. For ActewAGL Distribution, the principle driver of outages is third party hits to the network, however defective customer meter equipment (regulators) also contribute in part.

ActewAGL Distribution has in place a number of strategies to minimise hits to the network. ActewAGL Distribution participates in the *Dial before you dig* program—the national referral service for information on underground pipes and cables to assist customers to locate underground infrastructure. To support this, it has detailed GIS and mapping on the precise location of pipeline infrastructure.

ActewAGL Distribution also imposes targets and incentives on JAM under the DAMS Agreement in relation to the number of third party hits. This measure is also included as a Key Performance Indicator (KPI) in the access arrangement as it is a key driver of unplanned maintenance and therefore costs incurred over the access arrangement period. KPIs are published in chapter 13 of this access arrangement information.

The SAIFI outcomes show that the rate of interruptions is low for all gas networks. In part, these outcomes reflect the inherently reliable nature of gas distribution networks. Unlike electricity supply which has a much higher number of relatively brief interruptions, gas distribution inherently has fewer interruptions of inevitably longer duration.

4.4.2.5 Supply reliability and security of supply

There is a significant difference between supply reliability and security of supply. As part of the WTP study described above, customers were asked about their preferences for a number of service quality scenarios described by the frequency and duration of gas disruptions. The study sought information on customer WTP within a range of disruption up to 24 hours in duration.

A security of supply event represents a disruption of a different order of magnitude to those considered in the WTP study. A security of supply event that led to the loss of several suburbs (and up to the entire network) could take months to reinstate and, if it occurred in winter, would pose a serious threat to the health and safety of operational staff and gas customers as the system is re-established.

While not designed to consider this type of event, the WTP study gives an indication of possible customer willingness to pay to avoid a lengthy disruption. The NERA WTP model suggests that residential customers would be willing to pay around $220 per annum on average to move from a situation in which they experience an unannounced 24-hour outage on a weekday in winter every year to a situation in which they experience an unannounced 1-hour outage on a weekday some time after 8am in winter once every five years.[52] For non-residential customers, this figure is around $1,300 per annum on average.

This compares favourably with the costs of the security of supply projects discussed later in this access arrangement information, particularly when noting that the events prevented by security of supply investments are of much longer duration than those considered in the WTP study.

These security of supply projects are intended to manage upstream events that are outside the control of ActewAGL Distribution. Without management, upstream events can have a catastrophic impact on supply, potentially leading to widespread and lengthy residential loss of supply until network restoration and customer reinstatement is completed. As noted above, ActewAGL Distribution expects that it will need to manage more of such potential events throughout the access arrangement period, driven by the introduction of STTM hubs in Sydney and Adelaide. These events are also most likely to occur in winter. Management of events involves more detailed monitoring, requiring systems and expertise to identify issues, the issuing of supply curtailment requests to contract customers, as well as

[52] The WTP study results should not be used to extrapolate beyond a 24-hour disruption as it would be expected that there would be a reduction in incremental WTP for disruptions of longer duration.

negotiations with major shippers to manage nominations from the MSP and EGP to maintain network pressures.

These approaches, however, rely on the actions of other parties. For example, total winter peak demand on the ACT network is currently approximately 70 TJ. Contract customers only account for 2 TJ of demand, of which only 50 per cent can be expected to respond to a request for curtailment. Therefore, the scope to manage shortfalls through supply curtailment requests to contract customers is very limited.

Similarly, managing a shortfall by negotiating with retailers is likely to become more problematic and costly for ActewAGL Distribution after the introduction of the STTM. A simultaneous peak in Sydney and Melbourne may mean that marginal gas secured through the STTM becomes very expensive. High prices for marginal gas may also mean that retailers are less willing or able to shift nominations between the MSP and EGP, and that contract customers may be able to get better value for their curtailment under the STTM. There is also potential, given trends of increasing demand, that marginal gas is not available through the STTM at all. The risks to the ACT network of this circumstance are compounded by the inability to shed load due to limited contract customer supply curtailment availability.

It should be noted, however, that ActewAGL Distribution does not consider that its 2003 WTP study is strictly relevant to long duration outages of the type prevented by security of supply investments in this access arrangement information, and certainly should not be used as a sole justification of the prudency of these types of investments.

ActewAGL Distribution considers long term disruptions of the type described here to be unacceptable. A lengthy disruption poses significant health and safety risks, and ActewAGL Distribution’s customer base includes a number of institutions of national strategic importance. Maintaining heating gas supply to this customer base is important during Canberra’s cold winters. This has necessitated that ActewAGL Distribution propose options to secure supply in the ACT, as discussed in chapter 6 of this access arrangement information.

ActewAGL

5 Network demand and utilisation

This chapter of the access arrangement information discusses network demand and utilisation during the earlier access arrangement period and forecast demand over the access arrangement period.

5.1 Demand during the earlier access arrangement period

This section of the access arrangement information addresses the requirement of Rule 72(1)(a)(iii) for the access arrangement information to include usage of the pipeline over the earlier access arrangement period showing (A) minimum, maximum and average demand and (B) customer numbers in total and by tariff class".

Table 5.1 shows annual volumes of natural gas delivered, by customer class, during the earlier access arrangement period and a comparison to those approved by the ICRC. Figure 5.1 shows the reconciliation between annual volumes for all customer groups and that allowed by the ICRC.

Table 5.1 Actual and forecast natural gas demand 2004/05 – 2009/10

Terajoules	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*	
Tariff							
Access Arrangement	6,151	6,310	6,462	6,611	6,756	6,896	39,186
Actual Incurred/Budget	6,050	6,584	5,889	6,370	6,654	6,514	38,061
Variance	(101)	274	(573)	(241)	(102)	(382)	(1125)
Variance (per cent)	(1.6)	4.3	(8.9)	(3.6)	(1.5)	(5.5)	(2.9)
Contract							
Access Arrangement	1,057	1,040	1,023	1,007	990	973	6,090
Actual Incurred/Budget	1,018	1,082	1,038	1,020	1,100	1,149	6,407
Variance	(39)	42	15	13	110	176	317
Variance (per cent)	(3.7)	4.0	1.5	1.3	11.1	18.1	5.2
All customers							
Access Arrangement	7,208	7,350	7,485	7,618	7,746	7,869	45,276
Actual Incurred/Budget	7,068	7,666	6,927	7,390	7,754	7,663	44,468
Variance	(140)	316	(558)	(228)	8	(206)	(808)
Variance (per cent)	(1.9)	4.3	(7.5)	(3.0)	0.1	(2.6	(1.8)

Sources: Actuals from ActewAGL Distribution, forecast from NIEIR

Figure 5.1 Actual and forecast natural gas demand, all customers 2004/05 – 2009/10

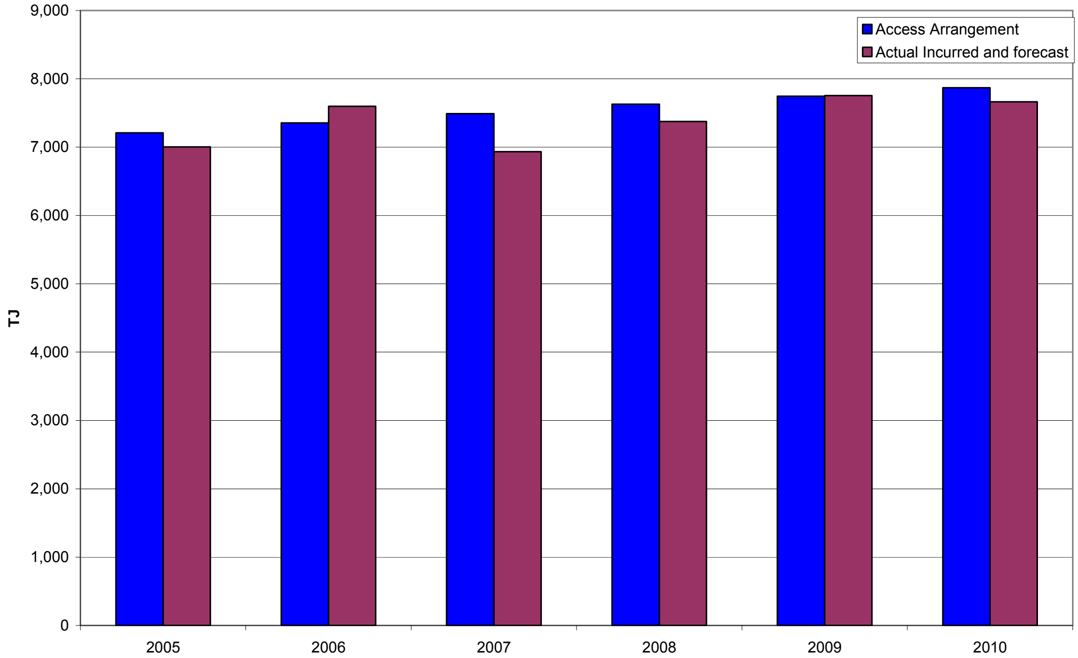


Table 5.2 provides information on actual and forecast peak throughput in the form of maximum daily quantity (MDQ) compared to that approved for the earlier access arrangement period.

Table 5.2 Actual and forecast booked maximum daily quantities 2004/05 – 2009/10

Gigajoules	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*
Access Arrangement	5,711	5,628	5,546	5,487	5,405	5,347
Actual Incurred/Budget	6,221	6,086	6,245	6,116	6,384	6,596
Variance Total	510	458	699	629	979	1249
Variance (per cent)	*8.9*	*8.1*	*12.6*	*11.5*	*18.1*	*23.3*

Source: JAM, NIEIR

Table 5.3 shows minimum and maximum daily consumption along with average annual gas consumption values for the tariff and contract market segments. The data show flat average demand, but generally increasing peak demand over the earlier access arrangement period.

Table 5.3 Actual minimum, maximum and average demand 2004/05 – 2007/08

Daily Consumption (TJ)	2004/05	2005/06	2006/07	2007/08
Tariff				
Minimum (daily)	1.7	0.8	2.6	2.1
Maximum (daily)	52.4	62.8	60.4	56.4
Average (annual)	17	17	17	17
Contract				
Minimum (daily)	1.2	1.1	1.4	1.8
Maximum (daily)	5.6	6.2	6.2	6.7
Average (annual)	3	3	3	3
Total				
Minimum (daily)	2.9	1.9	4	3.8
Maximum (daily)	58	69	67	63
Average (annual)	20	20	19	20

Source: ActewAGL Distribution and JAM

Figure 5.2 shows actual 2007/08 gas receipts into the ActewAGL Distribution network to demonstrate seasonal variation in gas demand. As indicated, the network experiences a distinct winter peak in gas demand.

Figure 5.2 Actual monthly gas receipts (TJ) 2007/08

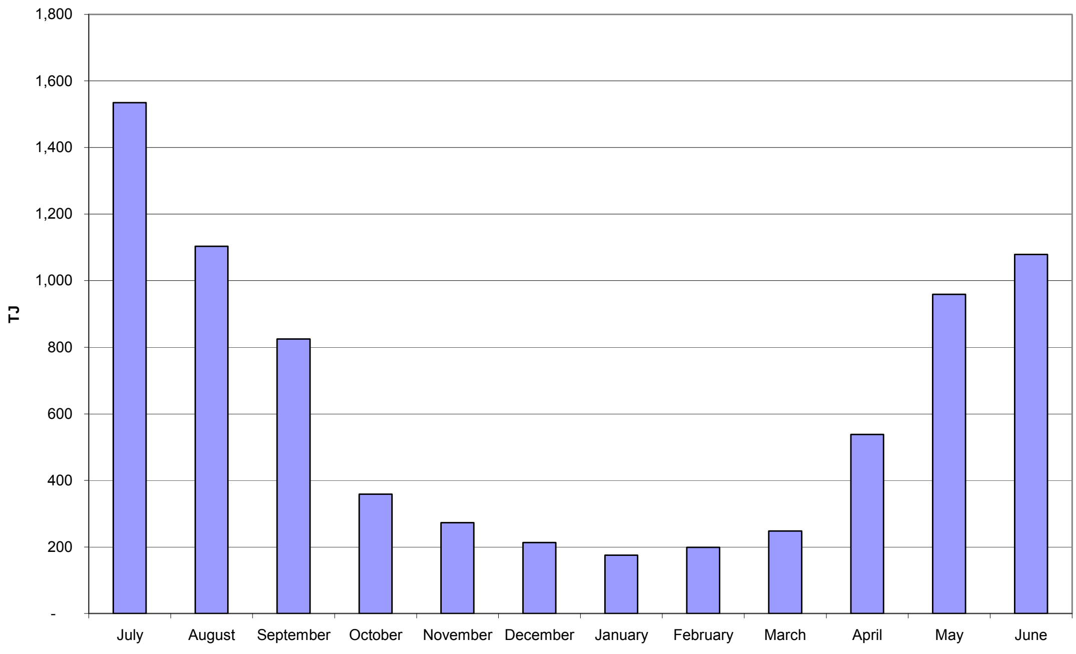
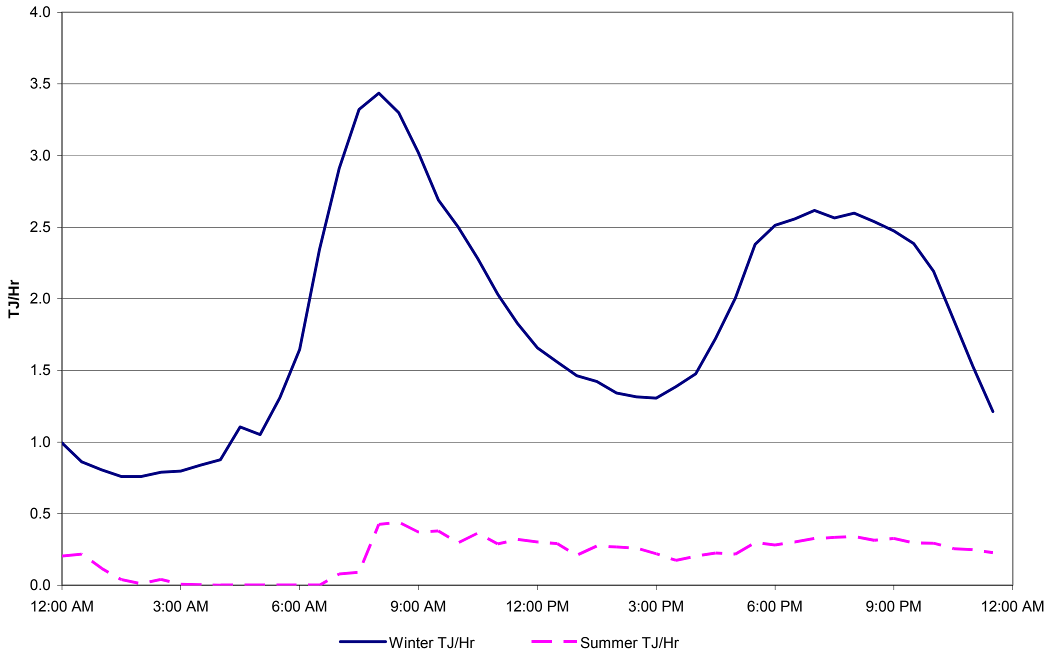


Figure 5.3 shows typical winter and summer diurnal profiles of gas throughput for ActewAGL Distribution's network. Households' behavioural patterns regarding the use of gas space heating appliances are largely responsible for the winter profile's pronounced

morning and evening peaks and high overall rate of gas use. In contrast, the summer profile, without the household space heating demand, shows a relatively constant levels of gas usage during the day time hours with the main drivers being: commercial; industrial and (non-space heating) residential uses. Maintaining ActewAGL Distribution's ability to accommodate peak winter demand is a major driver of network planning and capital expenditure activities.

Figure 5.3 Winter and summer diurnal throughput profiles



Note: The winter profile shown above is the average profile for the 6 day period 15 to 21 June 2009. The summer profile is the average of the six day period 5 to 10 January 2009.

Table 5.4 provides comparison between actual customer numbers and those allowed for in the earlier access arrangement.

Table 5.4 Actual and forecast customer numbers 2004/05 – 2009/10

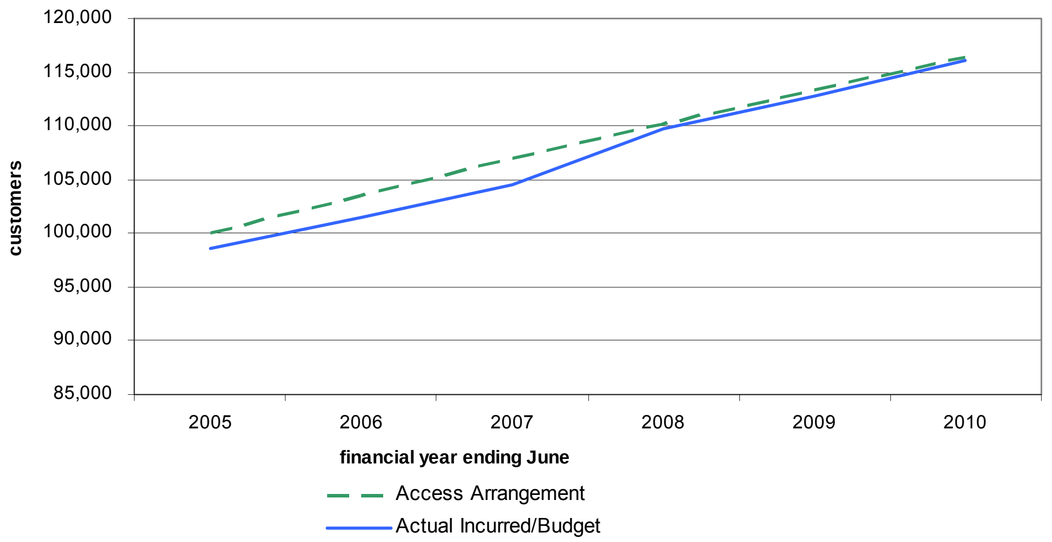
Number as at 30 June	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*
Tariff						
Access Arrangement	100,077	103,573	106,937	110,181	113,319	116,362
Actual Incurred/Budget	98,657	101,460	104,495	109,791	112,765	116,123
Variance	(1,420)	(2,113)	(2,442)	(390)	(554)	(239)
Variance (per cent)	(1.4)	(2.0)	(2.3)	(0.4)	(0.5)	(0.2)
Non-Tariff						
Access Arrangement	39	39	39	39	39	39
Actual Incurred/Budget	36	38	37	38	40	41
Variance Total	(3)	(1)	(2)	(1)	1	2
Variance (per cent)	(7.7)	(2.6)	(5.1)	(2.6)	2.6	5.1

Source: Actual data from ActewAGL Distribution, forecast data from NIEIR

The data in Table 5.1 show that tariff market demand on the network during the earlier access arrangement period was approximately 3 per cent below that allowed by the ICRC in the earlier access arrangement period. Contract market load (Table 5.2) as measured by MDQ was, on the other hand, consistently 8 to 23 per cent above that allowed by the ICRC in the earlier access arrangement.

Customer numbers fell short of those allowed in the early years of the earlier access arrangement period, commencing from a lower base in 2004/05 and recording lower growth until 2007/08, largely due to lower than forecast commencement of new estates and medium/high density residential developments. However, by the end of the period the number of customers is expected to be only 0.2 per cent below that forecast. Contributing to this outcome is a reclassification of a distribution network ‘customer’ to include attached sites not associated with a retailer, and an increase in the rate of medium/high density developments in 2008/09. Figure 5.4 illustrates this in terms of tariff customers (which represent over 99 per cent of total customer connections).

Figure 5.4 Comparison of actual tariff customer numbers and those in the access arrangement 2004/05 – 2009/10



5.1.1 Key historic trends

Lower than forecast customer numbers at the start of the earlier access arrangement period are an obvious cause of lower than forecast gas volumes. However, several additional key trends contribute to actual gas volumes being below forecast. These are described below and include improvements in energy efficiency, reduced hot water consumption and energy substitution.

5.1.1.1 Energy efficiency

Over the course of the earlier access arrangement period, improvements have been made in the construction of more energy efficient dwellings and appliances. During 2005 and 2006, energy efficiency standards for houses and buildings were incorporated into the Building Code of Australia (BCA).[53] Compliance with the BCA is required for approval of new dwellings in the ACT.

In addition, the prevalence of high energy efficiency appliances has increased. Since 1999, the average energy rating of instantaneous gas water heaters has increased (that is, they have become more efficient) with 82 per cent of models now having a rating of either 4 or 5 stars.[54] Modern instantaneous water heaters use less gas than storage heaters such that as storage-type units are replaced by instantaneous units, overall gas demand drops.

Research by the ABS indicates that there is evidence of an increasing trend to consider energy efficiency rating as an important factor in individual decision making for buying new heaters. For instance, between 2002 and 2008, the proportion of people surveyed who

[53] MCE, http://www.ret.gov.au/Documents/mce/energy-eff/nfee/committees/buildings/focus.html
[54] Mark Ellis & Associates, Energy Efficient Strategies and George Wilkenfeld & Associates, Energy Labelling & Minimum Energy Performance Standards for Domestic Gas Appliances, November 2002

considered energy efficiency in the purchasing decision for new heaters increased from 31.5 per cent to 34.7 per cent.[55]

5.1.1.2 Hot water conservation

In 2004, the ACT Government implemented the *Think Water Act Water* (TWAW) program which aimed to reduce the per capita water consumption in the ACT by 12 per cent by 2013 and by 25 per cent by 2023. A major component of TWAW was to encourage residents to take shorter showers and to install AAA (low flow) showerheads.

Water conservation devices such as shower timers and AAA showerheads may save up to 55 per cent of hot water use per shower, leading to significant reductions in the use of gas for water heating. The ACT Government provided rebates for AAA showerheads during 2004 and 2005, commenced an information and awareness program in July 2004 and, importantly, mandated the installation of water efficient showerheads in all new buildings from 2004.

The impact of the TWAW program on gas consumption was taken into account by ActewAGL Distribution in developing its proposal for the earlier access arrangement period. ActewAGL Distribution had assumed in its demand proposal a penetration rate for AAA showerheads of 25 per cent in new houses in 2004/05 and 100 per cent thereafter. However the ICRC and its consultants were not in agreement with ActewAGL Distribution regarding the impact of TWAW on hot water consumption. ActewAGL Distribution's gas demand forecast was accordingly revised upwards, giving rise to the outcome, illustrated above, where tariff customers gas consumption in the earlier access arrangement period is nearly 3 per cent below that in the ICRC's final decision.

ABS data also reveal that a major increase in penetration of water efficient shower heads occurred between 2004 and 2007 in existing dwellings, contemporaneous with the implementation of TWAW. In 2007, the ABS released survey data showing that 13.4 per cent of households in the ACT had installed a water saving device in their bathroom *in the last year*. This was the highest annual low flow showerhead installation rate of any Australian jurisdiction. In addition, in the same survey, 37.5 per cent of those ACT households surveyed reported taking shorter showers or showering less frequently, while 12 per cent also reported taking showers instead of baths a water saving practice.[56]

5.1.1.3 Energy Substitution

Electric powered reverse cycle air conditioner units are a substitute for gas heating. Over the course of the earlier access arrangement period, reverse cycle air conditioning grew in popularity in the ACT. Figure 5.5 shows that since 2005 the number of dwellings in the ACT that have reverse cycle heating as the main type of heating has increased by 5 per cent, against a 3 per cent reduction in electric heaters and a 2 per cent reduction in gas heaters.[57]

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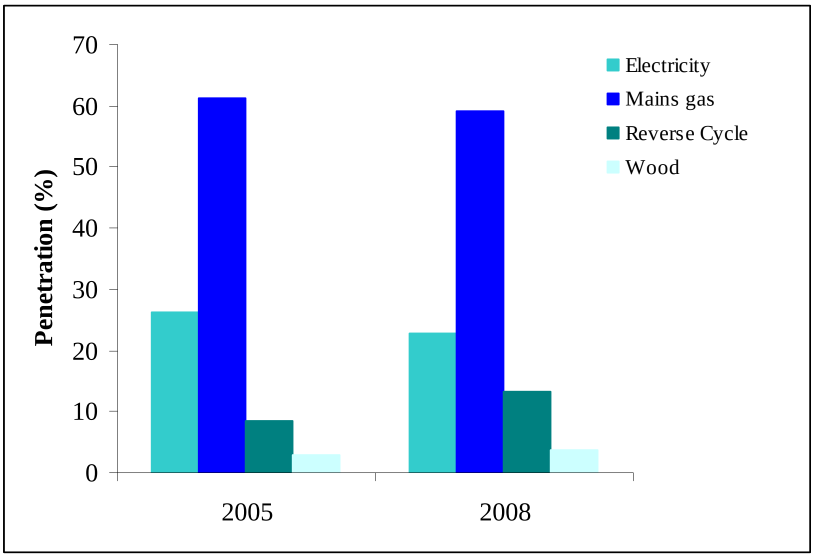
[55] ABS, Environmental Issues: energy use and conservation 4602.0.55.001, March 2008
[56] ABS, Environmental Issues: People's Views and Practice 4602.0 March 2007
[57] ABS, Environmental Issues: energy use and conservation, March 2008, p 60

Figure 5.5: Main type of heater in dwelling 2005 and 2008



Source: ABS, Environmental Issues: energy use and conservation, March 2008

These trends in energy efficiency, water conservation and energy substitution are expected to continue in to the access arrangement period and in fact may be accelerated by policies such as the introduction of Minimum Energy Performance Standards (MEPS) for gas appliances and the Ministerial Council on Energy's National Framework on Energy Efficiency as well as the fact that water availability and its sustainable use are a continuing priority for the ACT Government.

5.2 Demand forecasts

ActewAGL Distribution has forecast gas volumes and peak demand for the access arrangement period.

Rule 72(1)(d) requires access arrangement information to include "to the extent it is practicable to forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period, a forecast of pipeline capacity and utilisation of pipeline capacity over that period and the basis on which the forecast has been derived".

While capacity and utilisation information may be appropriate and relevant to transmission pipelines, the same information is not available or meaningful for distribution networks.

5.2.1 Forecast drivers and methodology

ActewAGL Distribution engaged the National Institute of Economic and Industry Research (NIEIR) to prepare an independent forecast of customer numbers and gas volumes for the access arrangement period. NIEIR's methodology is described below and its final report and forecast are provided as attachment G to this access arrangement information.

NIEIR provided an analysis of the key drivers of gas consumption for ActewAGL Distribution's customers and a quantitative forecast of the annual gas consumption of new and existing residential, business and large industrial customers.

5.2.2 Methodology

NIEIR's forecasts of natural gas sales were developed within a regional energy-economic model of the ACT. This methodology is underpinned by an economic forecast, disaggregated to household and industry levels for the statistical sub-divisions across the ACT. Although the ActewAGL Distribution region also covers Queanbeyan and Bungendore in NSW, for the purpose of econometric modelling, ACT data has been used given its dominant position in the region. Residential customer numbers are linked to NIEIR's projections of dwelling stock in the ACT, with adjustments for known residential developments in Queanbeyan.

ActewAGL's tariff customers include households and businesses. The residential and gas sales forecast was developed via an econometric model with the key drivers of demand being household income and gas prices. This forecast is integrated with an end use gas application model for residential customers. The application model is based on the penetration rate of gas appliances for cooking (ovens and cook tops), water heating and space heating. The application model was used to make adjustments for the expected impact of new policies on gas consumption by gas appliances in the different residential market segments (for example, existing customers, customers in new estates and electricity to gas conversions). Business projections were derived using a model which takes account of commercial output growth and movements in real gas prices.

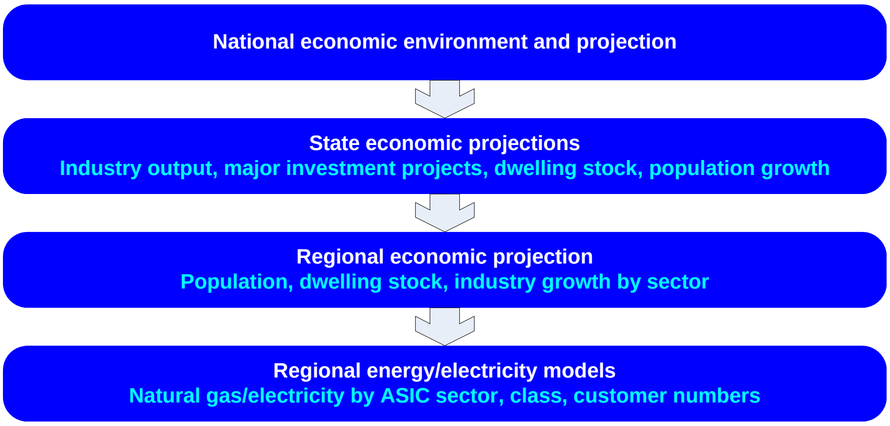
Using a similar methodology to that of the business tariff forecast, the gas sales forecast for the contract market was developed using industry-specific regression models that relate gas consumption to changes in output and real gas prices for that industry (incorporating lags in real prices to proxy long run responses or price elasticity). The output and price elasticities at the regional level were adjusted to reflect differences in gas use intensity between industries and regions. Forecasts of MDQ were also developed on an industry basis. The MDQ forecasts were determined from the energy growth by industry and industry specific load factors.

Econometric models for tariff and contract markets were calibrated using actual data supplied to NIEIR by ActewAGL Distribution. In order to make meaningful comparisons of year to year gas consumption, it is necessary to normalise observed consumption for temperature differences. The normalising adjustment is based on the *heating degree day* (HDD) metric which reflects the demand for energy needed to heat a home or business. HDD is calculated as the difference between average daily temperature and a base temperature of 18°C—the temperature above which a building does not need heating. HDD is recorded as zero when the average temperature is greater than 18°C as it is assumed there is no heating demand. The normalising adjustment is obtained by multiplying the *abnormal HDD,* that is, the difference between that year's observed HDD and the long term average HDD,[58] by a temperature sensitivity coefficient, estimated by regressing historical market performance on historical HDD. This forecast is made on a weather normalised basis with separate coefficients used for the tariff and contract markets. However, there is a long term trend of declining annual HDD which has also been factored into the forecast.

[58] For the purposes of the demand forecast, the long-term average number of HDD is estimated to be 1,812 and based on the average yearly HDD for the period 2003 and 2008.

Figure 5.6 illustrates the link between NIEIR's national economic models and regional residential and contract natural gas sales.

Figure 5.6: Regional energy-economic model



5.2.3 Drivers

This section describes the drivers underpinning the energy-economic model and the various adjustments required to reflect the effects of forecast changes in energy policy.

5.2.3.1 Economic activity

There is a positive relationship between economic activity and energy consumption. Growth in the outputs of gas intensive industries influences commercial gas sales. Growth in per capita income also influences residential gas sales.

NIEIR's national, state and regional economic models were used to generate an economic outlook for the ACT covering the access arrangement period. The forecast shows the strong influence of the global economic downturn on the ACT economy. Several influential macroeconomic aggregates show a strong decline in the later years of the earlier access arrangement period, particularly private consumption expenditure and business and government investment. It is not until the middle to later years of the access arrangement period that these aggregates are expected to show signs of recovery. Meanwhile, private dwelling investment is expected to peak early in the access arrangement period and will contract at an accelerating pace over the remaining years. Growth of the ACT gross state product (GSP) is forecast to decline over the course of the access arrangement period. Employment growth is forecast to be below or equal to population growth for four of the five years of the access arrangement. This is consistent with ActewAGL's wage escalators for the ACT described in section 9.2.1.4 of this access arrangement information.

Table 5.5 shows the major macroeconomic aggregates and indicators relevant to the energy-economic forecasting methodology.

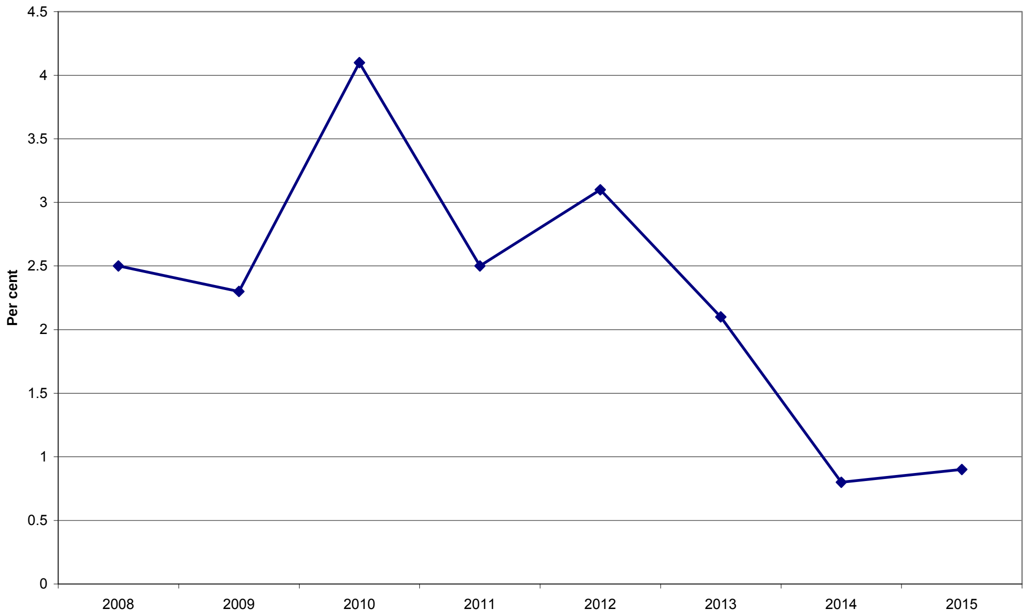
Table 5.5 Macroeconomic aggregates and selected indicators – ACT (per cent change)

	2007/08	2008/09	2090/10	2010/11	2011/12	2012/13	2013/14	2014/15	Compound growth rate
Private consumption	2.8	1.6	(3.0)	1.5	3.9	4.1	3.4	3.5	2.2
Private business investment	(9.0)	4.4	(22.7)	(24.6)	(2.7)	(2.4)	11.5	15.8	(3.7)
Private dwelling investment	(6.0)	(8.9)	1.3	0.8	1.5	(2.4)	(7.6)	(12.3)	(4.2)
Government consumption	2.9	4.2	4.6	5.0	4.7	3.7	2.3	2.3	3.7
Government investment	10.3	0.8	(6.9)	(8.9)	0.2	(1.9)	12.4	10.7	2.1
State final demand	2.2	2.9	(0.4)	1.4	3.9	3.2	3.3	3.4	2.5
Gross state product	2.5	2.3	4.1	2.5	3.1	2.1	0.8	0.9	2.3
Population	1.4	1.4	1.3	1.3	1.2	1.3	1.4	1.2	1.3
Employment	1.0	1.5	1.1	1.3	1.1	1.9	1.2	0.3	1.2

Source: NIEIR Natural gas projections for ActewAGL Distribution

Figure 5.7 shows the projected annual growth rate in GSP for the ACT for the period 2007/08 to 2014/15.

Figure 5.7 ACT projected gross state product growth 2007/08 to 2014/15



Note: Financial years ending June. Source: NIEIR

5.2.3.2 Gas Prices

Consumers respond to changes in gas prices by managing their energy usage. Prices are therefore a key driver of the demand forecast.

During the access arrangement period, the Australian Government is proposing to introduce its CPRS. The CPRS will comprise a cap and trade scheme on greenhouse gas emissions. As the combustion of natural gas generates carbon dioxide, a greenhouse gas, businesses that supply natural gas will be included in the CPRS. Under the proposed arrangements, CPRS obligations will fall on the entities that first supply gas for use in the domestic market (that is, gas producers). However, recognising that it is natural gas retailers that have the relationship with end users, the Government will require scheme obligations to be transferred with fuel supplies from producers at the top of the supply chain to natural gas retailers at the bottom.

This demand forecast incorporates the Australian Treasury modelling scenario *CPRS-5* as the likely scenario and includes a $20 per tonne price of carbon. NIEIR's estimate of gas prices, for the purposes of demand modelling, is shown below in Table 5.6.

Table 5.6 Forecast ACT gas prices (real, per cent change)

Year	Tariff	Contract	Total
2006/07	0.33	(0.66)	(0.30)
2007/08	1.17	0.19	0.54
2008/09	(0.67)	0.29	(0.05)
2009/10	(1.31)	(0.35)	(0.69)
2010/11	6.64	17.02	13.31
2011/12	0.30	0.70	0.56
2012/13	0.31	0.73	0.59
2013/14	0.33	0.76	0.61
2014/15	0.34	0.79	0.64

5.2.4 Adjustments

The Federal and ACT governments have developed a number of climate change related energy policies and initiatives that target a reduction gas consumption and greenhouse gas emissions. These policies cover construction of homes, alterations and extensions, and purchasing/replacement of household appliances. All such policies have the effect of reducing future demand for gas in the ACT. The demand forecast is adjusted for these policies through a gas application model whereby the forecast impact of new and altered policies on the penetration and consumption of gas appliances is used to adjust the forecast.

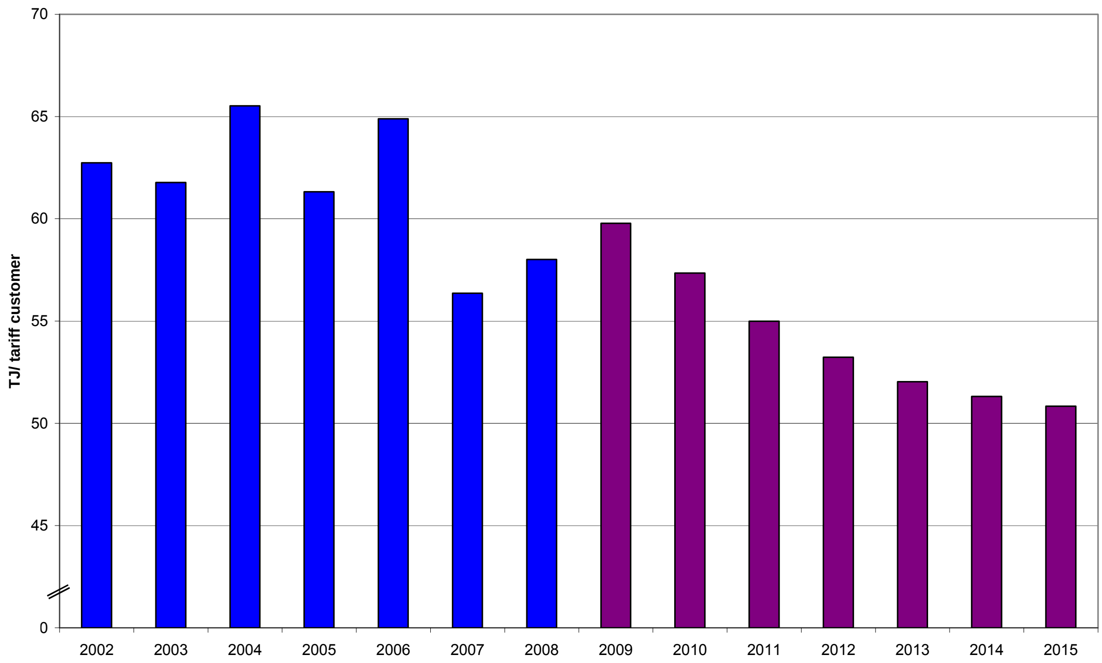
5.2.4.1 Number and type of residential connections

Between 2009/10 to 2014/15, the number of residential customers receiving gas via ActewAGL's network is expected to grow from 116,123 to 133,462, an increase of approximately 15 per cent. This increase is driven by both the connection of new dwellings (new estates and high-rise projects) and the conversion or connection of existing dwellings that currently use electricity only (electricity to gas or E to G). Whilst customer growth is an important driver of gas volumes, new customers consume less than existing customers. For example, customers in new estates consume on average 13 GJ/year less than existing customers and new E to G customers consume up to 22 GJ/year less. This result reflects a number of interacting factors, including:

- increased efficiency of new versus existing water and space heating appliances;
- continued use of electric, solar-electric and heat pumps for hot water; and
- increased usage of reverse cycle air conditioners in ACT and the rest of Australia.

Because new customers consume less than existing customers, the growth in gas volume is significantly lower than the customer growth rate. This phenomenon is demonstrated in Figure 5.8

Figure 5.8 Actual and forecast average gas consumption by tariff customers



Note: Actual data is not normalised. Warmer than average winters occurred in 2006/07 and 2008/09.

5.2.4.2 ACT House Energy Rating Scheme

ACT House Energy Rating Scheme (ACTHERS) requires all new housing to achieve a minimum energy efficiency requirement, which must be demonstrated both at the time of building approval and developmental approval application. Development approval requires the submission of an Energy Efficiency Rating (EER) Statement, demonstrating that the building meets 5-star energy efficiency requirements based on several design factors (for example, insulation, width of eaves, and double glazing). If the rating is acceptable, an EER approval is issued.

5.2.4.3 Gas appliance labelling

The gas labelling program is currently an industry voluntary scheme that was previously managed by the Australian Gas Association. A review of the scheme is under way by the gas industry and governments. Energy labels can be found on gas space heaters and gas water heaters (AS4552).

5.2.4.4 'Switch on Gas'

Switch on Gas will implement a nationally consistent regulation scheme for energy efficiency of gas appliances and equipment. This strategy is an important part of the package of measures being implemented by the MCE under the National Framework for Energy Efficiency and aims to progressively increase the energy efficiency of gas appliances and equipment beyond business-as-usual levels. Within 20 years, it is projected that *Switch on Gas* has the potential to reduce gas consumption by over 5 per cent below business-as-usual levels.

5.2.4.5 Mandatory Energy Performance Standards

The *Electricity Safety Amendment Regulations 2002* (ACT) give force to the national Minimum Energy Performance Standards (MEPS) and Energy Rating Labelling (ERL) in the ACT. The regulations specify the general requirements for MEPS for appliances, including penalties if a party does not comply with the requirements. Technical requirements for MEPS are set out in the relevant appliance standard, which is referenced in state regulations.

The proposed implementation of the MEPS for gas water heating requires the phasing out of all appliances below a 4.5 star rating. This will have a significant impact on the overall consumption in the ACT, as the consumption level from a 3 star hot water heater to a 5 star is a reduction of at least 15 per cent (see Table 5.7).

Table 5.7 Instantaneous and storage gas water heater consumption

Star Rating	Storage water heaters (MJ/year)	Instantaneous water heaters (MJ/year)
6	na	17,837
5	20,559	20,076
4	22,466	23,325
3	24,221	24,988
2	25,601	na
1	27,599	na

Source: NIEIR Natural gas projections for ActewAGL Distribution

The application model accounts for the impact of MEPS on the hot water appliance mix in the ACT. The hot water model differentiates between existing, E to G and new gas customers. It incorporates:

- scrapping/replacement of hot water units in existing dwellings and replacement by new units with a shift away from electric and low efficiency gas units to more efficient gas units;

- the share of gas hot water in new dwellings given competing technologies such as electric boosted solar and heat pumps; and
- an assumption on the rate of installation of gas services for E to G customers and a rate of scrapping and replacement.

5.2.4.6 Water efficient showerheads

The Australian Government, in collaboration with state and territory governments, has introduced a Water Efficiency Labelling and Standards (WELS) scheme. The scheme requires certain types of household water-using products to carry rating labels to reflect their relative water-use efficiency.

Showerheads receive a rating under the WELS scheme. This will have an indirect impact on gas consumption in the ACT.

The installation of water efficient showerheads in all new buildings was mandated in late 2004. The penetration of low flow showerheads across all homes is assumed to rise by around 3 per cent per annum, consistent with historic trends. With a reduction in water consumption, those dwellings with gas hot water heaters will see a reduction in their gas consumption. This reduction will be dependant on the energy efficiency of water heaters and will vary between dwellings. However, a reduction in demand due to the increased penetration of water efficient shower heads is expected.

5.2.4.7 Fiscal stimulus package (insulation)

The $4 billion Energy Efficient Homes (EEH) package is part of the Australian Government's Economic Stimulus Plan. The EEH package will install ceiling insulation in up to 2.9 million Australian homes and help up to 420,000 households install a solar hot water system.[59] The programs formally commence on 1 July 2009 and new procedures replace those under the Early Installation Guidelines that operate from 3 February 2009 to 30 June 2009.

Whilst the ACT has one of the highest rates of insulation in the country (only 14 per cent of homes are uninsulated), the demand forecast includes the assumption that there will be a 50 per cent take up of the EEH initiative with a saving in energy use from insulation of 25 per cent. Accordingly, the average heating gas usage for existing dwellings will fall over the life of the policy initiative through to 2012.

5.2.4.8 Mandatory Renewable Energy Target

The Australian Government's Mandatory Renewable Energy Target (MRET) was established on 1 April 2001 to encourage additional generation of electricity from renewable energy sources and to achieve reductions in greenhouse gas emissions. Amongst other things, the MRET scheme sets the framework for both the supply and demand of renewable energy certificates (RECs) via a RECs market. Owners of certain solar water heater installations are eligible for RECs. RECs apply both to new and existing dwelling replacements of hot water systems.

[59] http://www.environment.gov.au/energyefficiency/

5.2.4.9 The ACT Climate Change Strategy 2007-2025

The ACT Climate Change Strategy *Weathering the Change* replaces the ACT *Greenhouse Strategy 2000* and complements the *People, Place, Prosperity* and the *Think Water, Act Water* strategies.

The Climate Change Strategy, also described in chapter 4 of this access arrangement information, sets out the approaches the government will pursue between now and 2025 to support the broader community response to climate change. Detailed action plans will be developed at regular intervals during the life of the strategy.

The first Action Plan states 43 actions to be completed by 2011, some of these are directly related to energy use and relevant to gas consumption including the government's intention to:

- develop an energy policy;
- pursue carbon neutrality in government buildings;
- establish a $1million energy efficiency fund for ACT Government agencies;
- implement a renewable energy target (RET) in line with the NSW RET;
- implement energy efficiency improvements in government housing;
- provide a solar hot water rebate;
- pursue energy efficiency rating for all buildings; and
- investigate mandatory solar hot water for new houses.

5.2.4.10 Impact of gas marketing

The NIEIR demand forecast has been adjusted by ActewAGL Distribution for the impact of its gas network marketing campaign. ActewAGL Distribution's marketing program is designed to stem the erosion of gas consumption by existing gas users by encouraging:

- the installation of gas heaters for those existing gas consumers that do not have gas heating; and
- the replacement of gas heaters when existing gas heaters reach the end of their useful lives.

ActewAGL Distribution's marketing program includes the *Natural gas: the natural choice* campaign designed to increase the awareness of gas as an environmentally friendly energy source together with targeted incentives paid directly to appliance installers to encourage the uptake of gas appliances where up front cost present a barrier to the purchase of gas appliances.

In line with the anticipated impact of the marketing expenditure, NIEIR's baseline residential gas demand forecast has been increased by 18 TJ per annum (cumulatively) over the access arrangement period.

5.2.5 Demand Forecasts

Table 5.8 contains ActewAGL Distribution's gas volume forecast.

Table 5.8 Forecast gas sales 2010/11 to 2014/15

Terajoules	2010/11	2011/12	2012/13	2013/14	2014/15
System Total	7,711	7,696	7,744	7,834	7,946
Tariff	6,545	6,525	6,565	6,642	6,736
Residential Tariff	*4,992*	*4,973*	*5,003*	*5,039*	*5,080*
Business Tariff	*1,553*	*1,552*	*1,563*	*1,602*	*1,656*
Contract	1,166	1,171	1,179	1,192	1,210

Source: NIEIR Natural gas projections for ActewAGL Distribution

Table 5.9 contains ActewAGL Distribution's contract market MDQ forecast.

Table 5.9 Forecast Contract MDQ 2010/11 to 2014/15

Gigajoules	2010/11	2011/12	2012/13	2013/14	2014/15
System Total	6,677	6,693	6,721	6,764	6,827

Source: NIEIR Natural gas projections for ActewAGL Distribution

Table 5.10 shows the forecast maximum and average daily demand.

Table 5.10 Forecast maximum and average demand 2010/11 to 2014/15

Daily Consumption (TJ)	2010/11	2011/12	2012/13	2013/14	2014/15
Tariff					
Maximum (daily)	61.2	60.8	61.1	61.6	62.3
Average (annual)	17.9	17.8	17.8	18.0	18.2
Contract					
Maximum (daily)	6.6	6.6	6.6	6.7	6.8
Average (annual)	3.2	3.2	3.2	3.3	3.3
System Total					
Maximum (daily)	68.6	68.3	68.6	69.3	70.1
Average (annual)	21.1	21.0	21.1	21.3	21.5

Source: ActewAGL Distribution

Table 5.11 contains ActewAGL's forecast of customer numbers.

Table 5.11 Forecast customer numbers

Customer numbers	2010/11	2011/12	2012/13	2013/14	2014/15
System Total	119,751	123,470	127,071	130,326	133,462
Tariff Total	119,711	123,429	127,030	130,284	133,420
Residential Tariff	116,689	120,359	123,90	127,089	130,163
Business Tariff	3,021	3,071	3,130	3,196	3,257
Contract	41	41	41	41	42

Source: NIEIR Natural gas projections for ActewAGL Distribution

5.2.5.1 Use of the demand forecast

Demand forecasting is undertaken in two broad contexts with two different, but related, purposes as follows:

- **Gas quantity, pricing and connection planning:** The demand forecast, as described above, seeks to anticipate the market for gas consumption and gas connections on ActewAGL Distribution’s gas network. This type of forecast works from the top down (per Figure 5.6) and considers economic conditions that will influence gas consumption and connections as well as major trends in appliance installation and use and new policies that impact on gas consumption. It has three main uses as follows:
    - Pricing: The forecast is required to estimate the future level of gas consumption that will be the basis on which allowed revenue will be allocated to consumers through prices.
    - Market expansion: The forecast is used to estimate the number of new connections and market expansion capital expenditure.
    - Network planning: The forecast provides an input into the network capacity planning process, described briefly below and in more detail chapter 3 of this access arrangement information.
- **Network planning and design (or capacity development):** Network planning relies on spatial forecasts of gas demand on the different sections and components of the network rather than a network wide forecast as described above. The methodology takes customer specific usage, network measurements and peak usage models to calibrate SynerGEE network area models. Network planning practices seek to anticipate the peak demand during severe winter seasons (1 year in 20 for ‘coldness’) in order to identify capacity constraints that would jeopardise network performance and reliability. Importantly, this analysis relies on peak hourly demand, as this impacts on capacity, rather than annual throughput. While the peak load of some customers with continuous monitoring is known, in general, information regarding the peak load of individual customers in the network is not available. However, annual usage of all customers is recorded through the GASS functionalities and peak load is calculated from annual winter monitoring data. This annual usage information can be used to estimate peak loads in the network by the application of Load Factors and Diversity Factors to known and forecast customer numbers and annual usage.

Annual demand and peak demand may grow at different rates, as a result of shifts in appliance composition and/ or patterns of use, for example the increasing prevalence of instantaneous water heaters, shorter showers or the changed practices of large customers may all affect peak demand and need to be modelled to determine the effect on the network.

6 Capital expenditure

This chapter of the access arrangement information explains the process of assessment for capital expenditure, capital expenditure undertaken and to be undertaken during the earlier access arrangement period and the justification and forecast cost of capital projects during the access arrangement period.

6.1 Capital expenditure during the earlier access arrangement period

ActewAGL Distribution classifies system capital expenditure according to requirement as follows:

- *Market expansion* capital expenditure is undertaken to meet growth in customer numbers and connections;
- *Capacity development* capital expenditure addresses capacity development requirements of the overall network;
- *Stay in business* capital expenditure relates to the renewal and replacement of ageing network assets, condition of the assets, compliance requirements relating to safety, reliability and asset protection.

Non-system capital expenditure for the earlier access arrangement period is divided between *Non-system assets, Capitalised regulatory costs* and *IT system*.

All capital expenditure in the access arrangement information is consistent with ActewAGL Distribution's actual accounting and capitalised on an as incurred basis. ActewAGL's capitalisation policy can be found in attachment Q to this access arrangement information. The capital expenditure allowed by the ICRC for the earlier access arrangement period (in real 2004/05 dollars) is shown in Table 6.1.[60]

[60] Capital expenditure for the full period 2004/05 to 2009/10 is considered in this section. The actual commencement date of the access arrangement was 1 January 2005.

Table 6.1 ICRC final decision capital expenditure 2004/05 to 2009/10

$ '000 (2004/05)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Distribution system capital expenditure						
Market expansion	6.40	5.52	5.41	5.31	5.34	5.26
Capacity development	1.71	2.88	2.33	1.77	4.42	0.82
Stay in business	2.39	1.19	1.27	1.21	1.33	1.01
Total distribution system capital expenditure	10.50	9.59	9.01	8.29	11.09	7.09
Non-system capital expenditure						
Non system assets	-	-	-	-	-	-
Capitalised regulatory costs	1.60	-	-	-	-	-
IT system	0.50	-	-	-	-	-
Total non system capital expenditure	2.10	-	-	-	-	-
Total capital expenditure	12.60	9.59	9.01	8.29	11.09	7.09

In its 2004 final decision, the ICRC approved capital expenditure 2.8 per cent below that proposed by ActewAGL Distribution. This reduction focused on proposed *Market expansion* and *Stay in Business* capital expenditure. The ICRC made a 1.5 per cent cut to ActewAGL Distribution's total proposed budget for *Market expansion* capital expenditure[61] while for *Stay in business* capital expenditure, it determined a 20 per cent reduction to the total budget via a reduction in the allowed unit cost for meter replacements.

Table 6.2 compares the ICRC final decision and ActewAGL Distribution's actual and forecast capital expenditure for the earlier access arrangement period in constant terms (2009/10 dollars). ActewAGL Distribution's total capital expenditure for the earlier access arrangement period is expected to be $65.2 million. This will be $0.7m (or 1.1 per cent) below that allowed by the ICRC in the 2004 final decision as a result of prudent deferrals of meter replacement and of capacity development projects due to lower demand.

[61] Unit costs were set at $567/customer for medium pressure mains, $659/customer for service connections and $180/customer for meters.

Table 6.2 Comparison of ICRC final decision and outturn capital expenditure 2004/05 to 2009/10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
ICRC final decision 2004							
Market expansion	7.31	6.31	6.18	6.07	6.10	6.01	37.98
Capacity development	1.95	3.29	2.66	2.02	5.05	0.94	15.92
Stay in business	2.73	1.36	1.45	1.38	1.52	1.15	9.60
Total distribution system capital expenditure	12.00	10.96	10.29	9.47	12.67	8.10	63.49
Non-system capital expenditure							
Non system assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Regulatory capitalisation costs	1.83	0.00	0.00	0.00	0.00	0.00	1.83
IT system	0.57	0.00	0.00	0.00	0.00	0.00	0.57
Total non system capital expenditure	2.40	0.00	0.00	0.00	0.00	0.00	2.40
Total capital expenditure	**14.40**	**10.96**	**10.29**	**9.47**	**12.67**	**8.10**	**65.89**
Actual and forecast capital expenditure							
	Actual	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	
Market expansion	5.58	4.29	7.03	7.75	6.20	7.19	38.04
Capacity development	2.09	2.46	4.17	0.29	1.19	3.52	13.72
Stay in business	1.17	1.21	0.79	1.06	0.79	4.00	9.03
Total distribution system capital expenditure	**8.85**	**7.96**	**12.00**	**9.10**	**8.18**	**14.71**	**60.79**
Non-system capital expenditure							
Non system assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Regulatory capitalisation costs	2.06	0.00	0.00	0.00	0.91	0.54	3.51
IT system	0.33	0.10	0.08	0.00	0.00	0.38	0.90
Total non system capital expenditure	**2.39**	**0.10**	**0.08**	**0.00**	**0.91**	**0.92**	**4.40**
Total capital expenditure	**11.24**	**8.06**	**12.08**	**9.10**	**9.08**	**15.63**	**65.19**
Variance between ICRC final decision and ActewAGL Distribution actual and forecast capital expenditure							
Market expansion	1.73	2.01	(0.9)	(1.7)	(0.1)	(1.2)	(0.1)
Capacity development	(0.1)	0.83	(1.5)	1.73	3.86	(2.6)	2.2
Stay in business	1.56	0.15	0.66	0.32	0.73	(2.8)	0.6
Total distribution system capital expenditure	**3.15**	**3.00**	**(1.70)**	**0.37**	**4.50**	**(6.61)**	**2.70**
Non-system capital expenditure							
Non system assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Regulatory capitalisation costs	(0.2)	0.00	0.00	0.00	(0.9)	(0.5)	(1.68)
IT system	0.24	(0.1)	(0.1)	0.00	0.00	(0.4)	(0.32)
Total non system capital expenditure	**0.01**	**(0.10)**	**(0.08)**	**0.00**	**(0.91)**	**(0.92)**	**(2.00)**
Total capital expenditure	**3.16**	**2.89**	**(1.79)**	**0.37**	**3.59**	**(7.53)**	**0.70**

Note: Figures in parentheses denote actual, forecast capital expenditure above that approved by the ICRC in ActewAGL Distribution's 2004 access arrangement. Calculations include capital expenditure in financial year 2004/05, although the earlier access arrangement commenced on 1 January 2005.

Lower than forecast capital expenditure relative to the earlier access arrangement is comprised of:

- *Market expansion* capital expenditure $0.1 million (or 0.2 per cent) above the access arrangement allowance;
- *Capacity development* capital expenditure $2.2 million (or 13.8 per cent) below the access arrangement allowance;
- *Stay in business* capital expenditure $0.6 million (or 6.0 per cent) below the amounts allowed by the ICRC; and
- *Non-system* capital expenditure $2.0 million (83.5 per cent) above the allowance.

The majority of the spending below the ICRC capital expenditure allowance for the earlier access arrangement period is the result of prudent deferrals to meet changes of scope in *Capacity development* projects; primarily in 2007/08 and 2008/09. The major examples are the prudent deferrals until the access arrangement period of the Tuggeranong Primary Main Extension and Queanbeyan Primary Regulator Station projects. These deferrals are due to lower customer growth and average consumption than provided in the earlier access arrangement period. Peak consumption has however been closer to forecast.

Spending below the allowance in *Market expansion* capital expenditure in the opening years of the earlier access arrangement period occurred because of a slowdown in development demonstrated by the reduced growth in customer numbers. This outcome was exacerbated by the flow through of ICRC initiated upward adjustment to demand forecasts to mains construction in new estates and established areas (E to G conversions) at a higher level than proposed by ActewAGL Distribution. For further information about the demand development, see chapter 5 of this access arrangement information.

Stay in business capital expenditure remained below allowed expenditure for most of the access arrangement period due to prudent deferral of residential and industrial meter replacement during the earlier access arrangement period. These deferrals were based on statistical testing of individual populations of meters enabling five year extensions to effective lives.

Early year capital expenditure underspends in *Capacity development* and *Stay in business* categories are forecast to be significantly or completely countered in 2009/10. This expenditure is required to provide for security and reliability of the network.

Investment in the GIS to improve ActewAGL Distribution record keeping compliance and data accuracy, and costs for the access arrangement preparation in 2008/09 and 2009/10 which were not included in the forecast in the earlier access arrangement explains the overspend in total non-system capital expenditure.

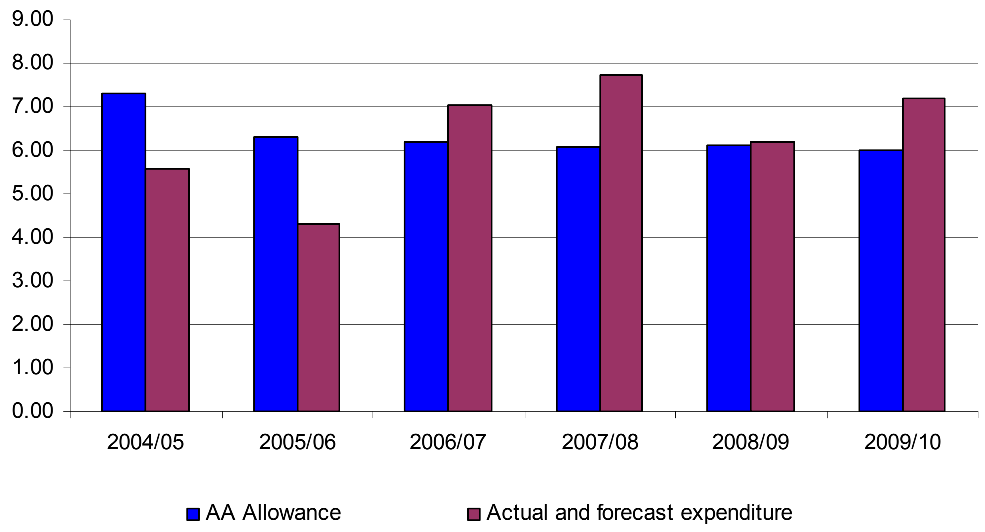
More detailed analysis of expenditure in each category is provided in the following sections.

6.1.1 Market expansion capital expenditure

Market expansion expenditure provides for direct growth in customer numbers and connections. It includes the cost of mains extensions, services (connections to premises) and meters for new customers.

The total capital expenditure allowance for market expansion in the earlier access arrangement was $38.0 million ($2009/10), $0.1 million more than the ICRC allowance. Figure 6.1 shows that underspends in the initial two years of the earlier access arrangement period are followed by a large rise in expenditure and overspends against the access arrangement forecasts in 2006/07 and 2007/08. Market expansion expenditure then returns to near forecast levels in 2008/09, but expenditure higher than the allowance is expected in 2009/10 due to a higher level of mains construction in new estates, predominantly in the Gungahlin district, which was not forecast at the time of the final decision in 2004.

Figure 6.1 Growth market expansion capital expenditure – 2004/05 to 2009/10



Some of the year-on-year variation in Figure 6.1 is attributable to timing differences between construction of mains extensions and connection of services, but most is explained by material variation in new customer mix.

An overview of the actual and estimated total market expansion capital expenditure during the earlier access arrangement period broken down into subclasses is set out in Table 6.3.

Table 6.3 Market expansion capital expenditure program in the earlier access arrangement period

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Mains Extension	2.51	1.27	3.58	4.19	2.73	3.85	18.14
Service Connection	2.11	2.06	2.08	2.45	2.33	2.40	13.43
Meters - tariff	0.57	0.57	0.64	0.58	0.48	0.59	3.43
Meters - contracts	0.40	0.39	0.73	0.53	0.65	0.35	3.04
Total market expansion	5.58	4.29	7.03	7.75	6.20	7.19	38.04

The majority of gas customers in the ACT are residential. Within the residential sector, connections are classified as new homes, new medium density and existing homes (E to G). The assumed customer mix in the earlier access arrangement was 48 per cent new homes, 19 per cent medium density and 34 per cent E to G. Market expansion actually delivered comprises 42 per cent new homes, 23 per cent medium density and 35 per cent E to G. The cost of mains provision for medium density dwellings, mostly urban infill projects, will be higher than provision of services to new homes and the actual average cost is therefore as a result 10 percent higher than the allowance.

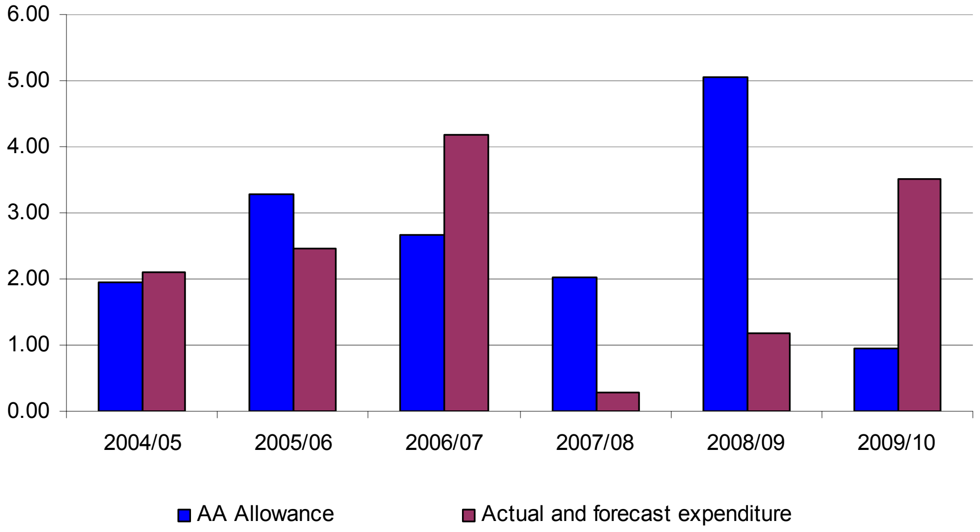
A small (0.2 per cent) overspend in this category during the earlier access arrangement period will occur as a result of the higher than anticipated average cost of connection due to the actual customer mix despite the lower than forecast customer growth.

6.1.2 Capacity development capital expenditure

Capital expenditure on capacity development projects provides additional network capacity to support projected load growth on the network and to ensure reliable supply to existing and new customers. Capacity development projects include extensions, interconnections and installation of new regulators (with or without upstream high pressure mains).

The total allowance for capacity development for the earlier access arrangement period was $15.9 million ($2009/10), of which $13.7 million will be spent. Figure 6.2 illustrates the pattern of capacity development capital expenditure across the earlier access arrangement period. It shows significant variation from year to year. This is explained by changes to scope of work and timing differences in project capitalisation.

Figure 6.2 Capacity development capital expenditure – 2004/05 to 2009/10



An overview of the actual and estimated total capacity development capital expenditure during the earlier access arrangement period is set out in Table 6.4.

Table 6.4 Capacity development capital expenditure program 2005-10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Mains - High Pressure	(0.0)	2.25	1.17	0.02	0.39	2.71	6.49
Mains - Medium Pressure	0.00	0.00	0.00	0.00	0.20	0.71	0.91
Facilities - High Pressure	2.14	0.21	2.85	0.27	0.00	0.10	5.56
Facilities - Medium Pressure	0.00	0.00	0.16	0.00	0.60	0.00	0.75
Total capacity development	2.09	2.46	4.17	0.29	1.19	3.52	13.72

The major causes of variation in this category are as follows:

- an underspend in 2005/06 is offset by a 2006/07 overspend in relation to the *Gungahlin/Belconnen primary mains interconnection* project which commenced in 2005/06, but was capitalised on completion in 2006/07;
- the main expenditure for 2006/07 was for the *Hoskinstown Custody Transfer Station water bath heater upgrade*. This project was included in the capital program at a cost of $1.64 million;
- for 2007/08, divergence from the allowed capital expenditure for capacity development was due to prudent deferral of the *Queanbeyan Primary Regulating Station and secondary main* project to 2010/11. Similarly, the *Tuggeranong primary mains extension* project proposed for 2008/09 has been prudently deferred until 2011/12. Both projects are described in section 6.2.2.2 under future capital expenditure; and

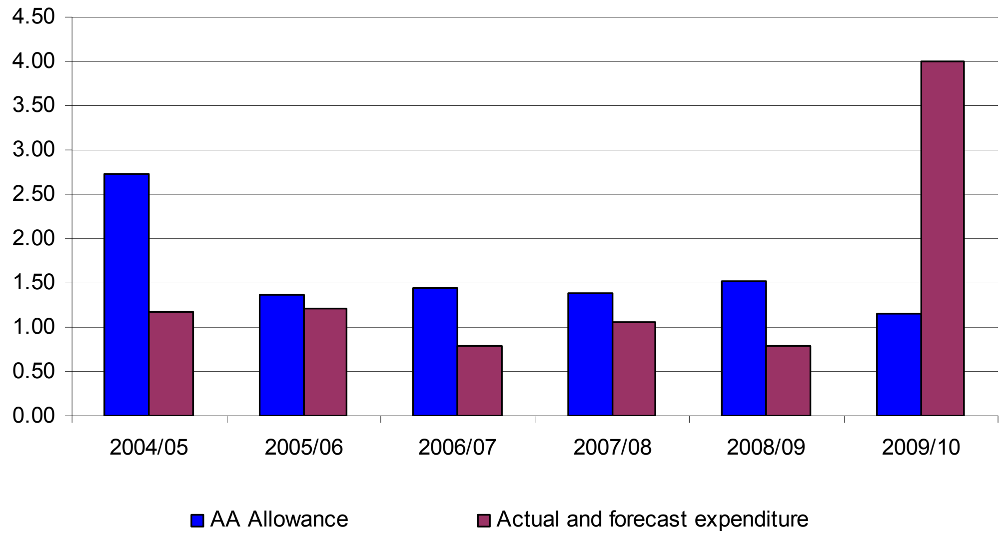
- the prudent deferral from 2006/07 to 2009/10 and change of scope for the *Queanbeyan/Jerrabomberra Interconnect capacity development* project, the timing of which was dependent on the development of the new road in that location, now scheduled for the fourth quarter of 2009.

As well as these major projects, several medium and minor capacity development projects have changes to scope of work and timing while new projects have been identified from risk assessments.[62]

6.1.3 Stay in business capital expenditure

Stay in business capital expenditure relates to renewals and upgrades of capital and is undertaken to ensure the reliability and security of the network. Capital expenditure in this category is compared to the annual allowance in the earlier access arrangement period in Figure 6.3.

Figure 6.3 Stay in business capital expenditure – 2004/05 to 2009/10



An overview of the actual and estimated total stay in business capital expenditure including sub categories during the earlier access arrangement period is set out in Table 6.5.

[62] Major capacity development projects are defined as projects with an estimated cost exceeding $400,000, medium project between $100,000 and $400,000 and minor projects, below $100,000.

Table 6.5 Stay in business capital expenditure program 2005-10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Facilities Renewal and Upgrade	0.51	0.36	0.00	0.30	0.08	3.30	4.55
Mains & Services Renewal and Upgrade	(0.01)	0.01	0.31	0.23	0.00	0.03	0.57
Residential Meters	0.53	0.40	0.29	0.27	0.38	0.28	2.16
I & C Meters	0.14	0.44	0.18	0.24	0.32	0.37	1.70
Other	0.00	0.00	0.00	0.02	0.00	0.02	0.04
Total stay in business	1.17	1.21	0.79	1.06	0.79	4.00	9.03

Figure 6.3 shows an underspend during 2004/05 to 2008/09 against the access arrangement allowance, followed by a sharp rise in 2009/10. This results in expenditure 6 per cent below allowance for the period as a whole.

Changes in expenditure of stay in business capital expenditure occur as follows:

- Capital expenditure for **meter renewal and upgrade** experienced a significant reduction as the result of the meter life extension program on the basis of satisfactory statistical testing of individual meter populations. This testing confirmed that an acceptable proportion of meters met regulatory approved accuracy requirements after 15 years of service. As a result, and with the concurrence of the technical regulator, the meter replacement program was prudently deferred five years for most meter types. The good general condition of the ActewAGL Distribution meter fleet is confirmed by low levels of customer billing complaints and service generated meter replacements;
- Forecast capital expenditure for **facilities renewal and upgrade** in 2009/10 has increased due to new projects providing *pigging* facilities, [63] and TRS upgrades.
    - A further $1.3 million is to be spent on *Canberra primary main scraper stations* (Watson–Phillip and Watson–Gungahlin) in 2009/10, which also is further described in section 6.2.2.3 below. This project involves the installation of scraper facilities at Watson, Phillip and Gungahlin. The primary main was designed and constructed to be *piggable*. *Pigging* is proposed because it is the most effective and efficient way to examine and validate the pipeline integrity for continuous safe operation;
    - Approximately $0.6 million is to be spent on the *Fyshwick TRS upgrade* project in 2009/10 and also further described in section 6.2.2.3 below. The scope of work includes an operational review for security of supply, and is forecast to require a water bath heater upgrade for an additional run.

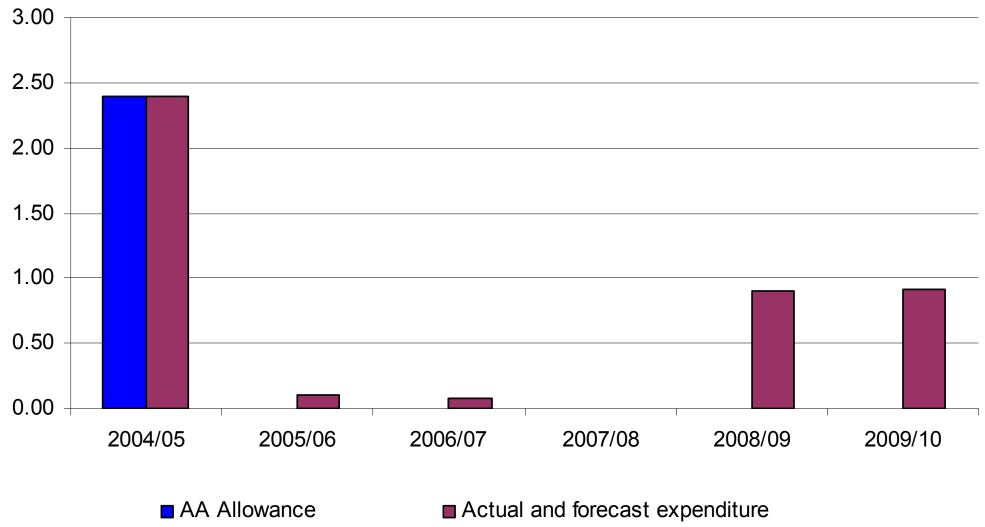
[63] A pipeline inspection gauge or *pig* is a tool that is sent down a pipeline and propelled by the pressure of the gas in the pipeline. Pigs require launching and retrieval facilities and associated equipment. There are four main uses for pigs: physical separation between different liquids being transported in pipelines; internal cleaning of pipelines; inspection of the condition of pipeline walls; and capturing and recording geometric information relating to pipelines.

- small amounts of capital expenditure for **mains and service renewal** projects identified by risk assessment in the annual capital plan.

6.1.4 Non system assets capital expenditure

Non system assets capital expenditure incurred by ActewAGL Distribution relates to IT system equipment and regulatory costs (capitalised in the earlier access arrangement period). The annual expenditure on non system capital expenditure compared to the allowance in the 2004 access arrangement is illustrated in Figure 6.4.

Figure 6.4 Non system capital expenditure – 2004/05 to 2009/10



An overview of the actual and estimated total non-system assets capital expenditure during the earlier access arrangement period is set out in Table 6.6.

Table 6.6 Non system assets capital expenditure program 2005-10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Regulatory Costs	2.06	0.00	0.00	0.00	0.91	0.54	3.51
IT Systems	0.33	0.10	0.08	0.00	0.00	0.38	0.90
Total non system assets capital expenditure	2.39	0.10	0.08	0.00	0.91	0.92	4.40

Figure 6.4 shows that ActewAGL Distribution only was provided an allowance for the first year of the earlier access arrangement period for regulatory costs and GIS.

Consistent with the treatment of the regulatory costs provided for the decision for the earlier access arrangement period, ActewAGL Distribution has capitalised regulatory costs in 2008/09 and 2009/10 for preparation of the access arrangement. ActewAGL Distribution will expense regulatory costs in the access arrangement period, consistent with the approach in the AER electricity distribution price determination for 2009-14. In addition to the allocation in the final decision, ActewAGL Distribution has prudently invested $0.3

million in further enhancements of the GIS to improve record keeping compliance and data accuracy.

6.1.5 Capital expenditure by asset class

This section of the access arrangement information addresses the requirement of rule 72(1)(a)(i) for the access arrangement information to include "capital expenditure (by asset class) over the earlier access arrangement period".

ActewAGL Distribution records capital expenditure by purpose, as outlined in the previous discussion. Asset type information is then derived from these records.

ActewAGL Distribution's actual capital expenditure for 2004/05 to 2007/08 and forecast capital expenditure for 2008/09 and 2009/10 by asset class is provided in Table 6.7.

Table 6.7 Capital expenditure by asset class 2004–10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Distribution system							
TRS & DRS - Valves & Regulators	2.65	0.57	3.01	0.57	0.67	3.40	10.87
HP Mains (inc DRS & TRS)	(0.1)	2.26	1.47	0.19	0.40	2.71	6.97
MP Mains	2.51	1.27	3.59	4.27	2.93	4.61	19.19
Meters - Tariff	1.57	1.73	1.82	1.51	1.76	1.32	9.70
Meters - Contract	0.06	0.07	0.03	0.12	0.08	0.28	0.64
MP Services	2.11	2.06	2.08	2.45	2.33	2.40	13.43
HP Services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total distribution system	8.85	7.96	12.00	9.10	8.18	14.71	60.79
Non system							
IT system	0.33	0.10	0.08	0.00	0.00	0.38	0.90
Regulatory costs (capitalised)	2.06	0.00	0.00	0.00	0.91	0.54	3.51
Total non system	2.39	0.10	0.08	0.00	0.91	0.92	4.40
Total	**11.24**	**8.06**	**12.08**	**9.10**	**9.08**	**15.63**	**65.19**

Over the earlier access arrangement period, ActewAGL Distribution does not expect to have any non conforming capital expenditure identified as recovered by surcharge or added to a speculative investment account. Section 6.2.3.1 below specifies capital contributions in the earlier access arrangement period (which have not been excluded from Table 6.7 above).

6.2 Forecast capital expenditure

Rule 72(1)(c)(i) requires the access arrangement information to include in relation to the projected capital base over the access arrangement period:

a forecast of conforming capital expenditure for the period and the basis for the forecast

Rule 79(1) defines *conforming capital expenditure* as that which:

- would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services; and
- is justifiable on a ground specified in Rule 79(2).

According to rule 79(2), capital expenditure is justifiable where:

- its overall economic value is positive; or
- the present value of the expected incremental revenue to be generated as the result of the expenditure exceeds the amount of the capital expenditure; or
- the capital expenditure is necessary for any of the following:
  - to maintain and improve the safety of services;
  - to maintain the integrity of services;
  - to comply with a regulatory obligation or requirement;
  - to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or
- it is jointly attributable to incremental services and one of the criteria of the point immediately above, with the incremental service satisfying the present value test in the second dot point above.

6.2.1 Overview of capital expenditure forecasts

ActewAGL Distribution's forecast gas network capital expenditure is shown in Table 6.8. Along with the procedures in chapter 3 of this access arrangement information, this section shows how forecast capital expenditure complies with Rule 79(1). Rule 79(2) justification is discussed under the respective asset drivers in sections 6.2.2.1 to 6.2.2.4 below.

Table 6.8 Forecast capital expenditure 2010–15 by justification

$ million (2008/09)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Distribution system						
Market expansion	8.78	7.13	7.07	6.23	5.88	35.09
Capacity development	4.81	13.64	0.68	0.32	2.12	21.57
Stay in business	10.32	52.47	86.99	3.79	3.03	156.60
Total	**23.91**	**73.24**	**94.74**	**10.34**	**11.03**	**213.26**
Non system						
IT system	0.32	0.31	0.45	0.10	0.00	1.18
*Total gross capital expenditure**	**24.23**	**73.56**	**95.19**	**10.43**	**11.03**	**214.44**

* Excludes equity raising costs.

Table 6.9 Forecast capital expenditure 2010–15 by asset type

$ million (2008/09)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Distribution system						
TRS & DRS - Valves & Regulators	11.43	3.52	0.34	0.82	0.36	16.48
HP Mains (inc DRS & TRS)	0.80	60.66	83.73	0.00	1.22	146.40
MP Mains	4.89	3.60	3.68	2.69	2.97	17.83
Meters - Tariff	3.22	2.39	3.90	3.81	3.61	16.92
Meters - Contract	0.56	0.18	0.20	0.29	0.21	1.44
MP Services	3.01	2.89	2.89	2.72	2.66	14.18
HP Services	0.00	0.00	0.00	0.00	0.00	0.00
Non system						
IT System	0.32	0.31	0.45	0.10	0.00	1.18
Total capital expenditure	**24.23**	**73.56**	**95.19**	**10.43**	**11.03**	**214.44**

The derivation of the capital expenditure forecasts is outlined in the following sections, with is provided in attachments as nominated.

The following sections together fulfil the element of the requirement in Rule 72(1)(c)(i) for the access arrangement information to address “the *basis* for the forecast” of conforming capital expenditure.

6.2.1.1 Forecast methodology for estimating capital expenditure

Forecasts of capital expenditure for the network during the access arrangement period have been derived using a zero-base approach using DAMS Agreement unit rates for 2009/10, engineering estimates and engineering assessments of specific major capital projects. The base estimates for the engineering assessments are in 2008/09 dollars. These have been escalated using Competition Economists Group (CEG) input cost escalators described below. All other capital expenditure has been estimated based on the DAMS Agreement[64] unit rates or engineering estimates for smaller projects and are in 2009/10 dollars.

Unit rates under the DAMS Agreement have been commercially negotiated. ActewAGL Distribution has engaged Parsons Brinckerhoff to provide an independent assessment of the estimation of unit rates used in the proposed expenditure program. The assessment can be found in confidential attachment I to this access arrangement information. All capital expenditure with the exception of that associated with GIS has been forecast by JAM. GIS capital expenditure, estimated by Ecowise Environmental, is provided at attachment H to this access arrangement information.

[64] According to the DAMS, the CPI is determined using the average of the four quarters Jan-Dec 2008 published by the ABS to escalate the capital expenditure into 09/10. This ensures that the DAMS Agreement is based on actual numbers and not forecasts.

No contingency costs have been included in the estimated cost of capital projects although there is a material risk that some estimates will be too low. As discussed in chapter 3 of this access arrangement information, it is likely that the cost estimates for each project is skewed such that the likelihood that a project will come in greater than the estimate is materially higher than the likelihood that it will come in under.

6.2.1.2 Escalators

Base estimates of capital expenditure for the access arrangement period have been escalated using escalators estimated by CEG. CEG's report is provided at attachment J to this access arrangement information.

As described, the capital expenditure has been estimated using the DAMS Agreement unit rates for 2009/10, engineering estimates for smaller projects or through engineering assessments. Approximately 75 per cent of the capital expenditures, including the Hoskinstown-Fyshwick Loop, are based on engineering assessments. The engineering assessments are concept estimates in 2008/09 dollars. The other capital expenditures that are based on the DAMS Agreement unit rates and engineering estimates are in 2009/10 dollars. All capital expenditure is assumed to be completed at the end of the financial year and the escalators have been developed to represent end of the financial year values (June).

The escalation factors that have been developed are:

- labour paid under enterprise bargaining agreements (EBAs);
- labour paid under individual contracts;
- aluminium;
- steel;
- nylon-11/polyethylene; and
- concrete.

Escalation factor estimates are set out in Table 6.10.

Table 6.10 Real escalation factors for ActewAGL

Midpoint of calendar year	2009	2010	2011	2012	2013	2014
EBA EGW labour	1.1%	2.3%	2.2%	2.0%	1.7%	1.7%
Contract EGW labour	1.6%	1.5%	1.6%	3.1%	4.4%	4.3%
Aluminium	-14.1%	12.5%	9.2%	8.6%	7.0%	6.2%
Steel	-21.5%	9.9%	6.5%	3.8%	1.0%	0.9%
Polyethylene	-2.6%	4.5%	1.5%	0.7%	0.2%	0.2%
Concrete	2.7%	0.7%	2.7%	3.6%	2.3%	1.3%

CEG has separately estimated the extent to which the planned introduction of an emissions trading scheme is likely to affect the escalation factors for aluminium, steel, nylon-11/polyethylene and concrete. The effect on the escalators is shown in Table 6.11.

Table 6.11 Effect of emissions trading scheme on escalation factors

Calendar year	2009	2010	2011	2012	2013	2014
Aluminium	0.0%	0.0%	0.1%	0.4%	0.3%	0.0%
Steel	0.0%	0.0%	0.3%	1.1%	0.7%	0.1%
Polyethylene	0.0%	0.0%	0.2%	0.7%	0.5%	0.1%
Concrete	0.0%	0.0%	0.1%	0.4%	0.3%	0.0%

The methodology applied is broadly consistent with the methodology applied by the AER in its calculation of escalators for its final determinations for the NSW and ACT and Tasmanian electricity businesses in April 2009. A summary of the methods of estimation for the input parameters is provided in Box 6.1.

A split of forecast input costs for all capital expenditure has been developed. Input costs have been estimated separately for each engineering assessment and for all subcategories — capacity development, market expansion and stay in business. The estimates are based on JAM's actual data and engineers' best assessments.

ActewAGL Distribution has used the escalators in Table 6.10 and Table 6.11 to escalate the capital expenditure based on the input cost data composition provided by JAM. The GIS Network IT System, which is the only capital expenditure estimated directly by ActewAGL Distribution, has been escalated using the contract labour escalator above as the best available proxy.

Box 6.1 Summary of estimation of input parameters

EBA EGW labour – CEG has used the average of forecasts from BIS Shrapnel, Macromonitor and Econtech in the EGW sector for New South Wales. JAM is a national service provider but the salaries based on EBA agreements in Sydney. Although the staff might be located in the ACT, they effectively follow the NSW salary development.

Contract EGW labour – CEG has used forecasts from Macromonitor and BIS Shrapnel for the EGW sector in New South Wales. Although ActewAGL Distribution serves customers in the ACT, a majority of JAM's non-EBA staff are located in Sydney. Therefore, New South Wales specific forecasts are likely to be reasonable. Econtech's report has not been used since the forecast is more general and not as representative for these salaries.

Aluminium – London Metals Exchange prices for aluminium averaged over the month of April 2009 has been obtained. Future prices for the aluminium products have been used until July 2011, which is the longest dated future. For the remaining years, Consensus Economics long term 5-10 year forecasts in real dollars has been used. Consistent with the AER's previous methodology, the long-term forecast has been applied to a horizon of 7.5 years.

Steel – Consensus Economics hot-rolled coil short term and long term real forecasts have been used, which provides significantly better future prices information than steel pipes.

Crude oil – Future prices of crude oil has been estimated since they are of assistance in estimating nylon-11 and polyethylene. Crude oil futures (NYMEX Crude Oil Light) have been sourced from Chicago Mercantile Exchange. CEG has averaged NYMEX prices over 20 days to 24 April 2009 for use in the estimation of escalation factors. NYMEX futures are available to December 2017 and have been relied upon to develop forecasts.

Nylon-11 and polyethylene – Nylon-11 is used in many smaller diameter pipes purchased by ActewAGL Distribution. There is only limited futures information available for Nylon-11. Since polyethylene is common substitute for Nylon-11 and also used by ActewAGL Distribution and in other Australian networks, it is reasonable to approximate the future prices of Nylon-11 with polyethylene. Like Nylon-11, there is no significant futures trading in polyethylene. However, there is a pricing relationship between crude oil and plastics since oil is an important component. Based on a long time series of data, CEG notes that 17 per cent of the crude oil prices is passed over to polyethylene over a three months period. Even though it is unlikely to be an accurate measure at any particular point in time, it represents the best representation of the longer term data. Since Nylon-11 is a substitute for polyethylene, the price relation between polyethylene and crude has been used to forecast the expected price path of Nylon-11.

Concrete – Forecast future prices of concrete from Macromonitor has been used.

6.2.2 Capital projects by driver

The following sections describe forecast capital expenditure in the access arrangement period and the estimation methods used. Forecasts under the market expansion, capacity development and stay in business classifications have been developed by JAM, with the exception of Project MIMI (discussed in Box 6.9) that is developed by ActewAGL Distribution in stay in business capital expenditure, and those for non-system assets by ActewAGL Distribution.

6.2.2.1 Market expansion – methodology and forecast

The process for determining forecast market expansion capital expenditure involves forecasting the number of new connections by type and applying a predetermined cost (a unit rate) to each type of connection. The forecast methodology takes account of:

- data from forecasting bodies such as the ABS, industry groups, appliance manufacturers and federal, state/territory and local government;

- future land development activity identified through the ACT Government land release programs, preliminary assessments, agency liaison/consultation processes and forecasts through BIS Shrapnel;
- major future public and private development initiatives identified through media and public announcements;
- reviews of ACT areas not currently serviced and an average historic request rate for new gas access services in these areas;
- the time difference between construction of a main and connection of the service;
- compliance with current safety and servicing obligation requirements; and
- escalation of materials costs as described above and the demand forecast in chapter 5 of this access arrangement information.

The unit rates used in the market expansion forecast are shown in confidential attachment K to this access arrangement information. These have also been reviewed by consultants Parsons Brinckerhoff (attachment I).

The type of connection determines the required components such as length of main per connection. Requirements for each segment of the market, for example, the length, size and material used, have been built up from historic experience.

Since a large proportion of the existing homes in Canberra have access to the gas network, new homes are the major driver of the market expansion capital expenditure. It is forecast that an increasing proportion of connections in the ACT/Queanbeyan area will come from this market. Currently all new homes have access to natural gas.

The Market expansion model extrapolates forecast numbers of units from historical trends using the GASS system, further explained in chapter 3. Where prospective land releases are identified, the database is used to generate the estimated length of pipes and works required.

Before market expansion capital expenditure is incorporated in JAM's forward work program, it goes through the RUGS process where its financial viability is assessed. This assessment determines whether or not the proposed expansion should proceed as conforming capital expenditure, or whether a capital contribution is required. The financial assessment evaluates a proposed project's net present value and internal rate of return consistent with Rule 79(4). The RUGS process is further outlined in chapter 3 and at attachment Q to this access arrangement information.

Several of the market expansion projects proposed for the access arrangement period, particularly those in the latter part, are subject to uncertainty. Development in Canberra is largely dependent on land availability and federal government policy. Because of Commonwealth's dominance of the ACT labour market, an increase or decrease in the size of the public sector can have a major impact on construction activity.

The forecast market expansion capital expenditure for the access arrangement period is set out in Table 6.12. The market expansion forecast makes provision only for expected developments, that is, no contingency factor is included.

Table 6.12 Market expansion capital expenditure program 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Mains Extension	4.65	3.05	2.95	2.30	1.98	14.9
Service Connection	3.01	2.89	2.89	2.72	2.66	14.2
Meters – residential	0.73	0.77	0.79	0.75	0.75	3.8
Meters - commercial	0.39	0.42	0.44	0.46	0.48	2.2
Total market expansion	8.78	7.13	7.07	6.23	5.88	35.1

The market expansion capital expenditure program will continue to build on the existing program. Market expansion capital expenditure is forecast to be $35.1 million, which is 8.1 per cent higher than that of the previous five years. The expenditure for mains extensions is expected to increase by $0.8 million in 2010/11. This is mainly due to the supply to a cogeneration facility to be built for the Hume data centre which requires 1,900 metres of secondary steel. Expenditure for service connections will increase in 2010/11 due to infill in the Canberra medium density residential suburb of Swinger Hill. Meter expenditure is a result of the new developments and infill. For the remaining part of the access arrangement period, expenditures will decrease due to a reduction in known land releases, new developments and expected infill.

Major developments requiring market expansion capital expenditure proposed to be undertaken during the access arrangement period are:

- Molonglo District and North Weston new development;
- Swinger Hill infill; and
- Googong.

All market expansion capital expenditure is relevant to the incremental (growth) capital expenditure category of Rule 79(2)(b).

6.2.2.2 Capacity development – methodology and forecast

ActewAGL Distribution's *Capacity Development Plan* details projects required to support the ongoing load growth on the network. Projects are identified through the network validation and planning process, with a risk assessment approach used to determine the timing of each project.

The need for capacity development projects is based on current organic load growth forecasts and committed contract loads, revised annually. The risk assessment approach to timing means that the projects are scheduled to be undertaken when severe winter demand scenario forecasts exceed acceptable operating levels. This process is further explained in chapter 3. Capacity developments for large industrial loads, received as part of the *Transportation requests for services* process, are assessed on a case-by-case basis.

The process for determining forecast capacity development capital expenditure takes account of:

- utilisation of the existing network;
- future development plans as described under market expansion in section 6.2.2.1 above;
- spatial demand forecasts that seek to anticipate the peak demand during severe winter seasons for sections of the network or network areas;[65]
- assessed capacity and performance of the distribution network assets and impacts of asset failures on network supply or loss of supply using the SynerGEE gas network model as explained in chapter 3 of this access arrangement information;
- reliability risks and capacity priorities;
- compliance with technical standards and requirements of the Technical Regulator;
- maintenance of service standard performance;
- health, safety and environmental issues;
- unit rates; and
- escalation of material costs as described in section 6.2.1.2 above.

Required pipeline lengths are estimated using spatial data for each project. Pipe lengths are then multiplied by the relevant unit rates.

A miscellaneous expenditure of $100,000 (base year before escalation) has been included for each year of the access arrangement period to account for smaller capacity development projects that arise each winter, but which cannot be specifically identified in advance. This estimate is in line with historic expenditure levels. Apart from this allocation for miscellaneous unidentified works, all other capacity development projects are specifically identified and the need for the project is confirmed via the annual distribution network performance reviews.

The forecast capacity development capital expenditure for the access arrangement period is set out in Table 6.13.

[65] The methodology uses customer specific usage and peak usage models to calibrate network area models.

Table 6.13 Capacity development capital expenditure program 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Mains – High Pressure	0.80	10.11	0.00	0.00	1.22	12.13
Mains- Medium Pressure	0.20	0.51	0.68	0.32	0.91	2.61
Facilities – High Pressure	3.81	3.03	0.00	0.00	0.00	6.83
Facilities – Medium Pressure	0.00	0.00	0.00	0.00	0.00	0.00
Total capacity development	4.81	13.64	0.68	0.32	2.12	21.57

All capacity development capital expenditure is relevant to Rule 79(2)(c)(iv) for meeting future levels of demand (except those related to network expansion). Capacity development projects proposed during the access arrangement period are described in the AMP.

Capacity development capital expenditure is forecast to increase by $10.1 million compared to the prior five years. The increase is largely due to a small number of relatively large projects mainly in the beginning of the access arrangement period including:

- the Tuggeranong Primary Mains Extension and the Tuggeranong PRS in 2010/11 and 2011/12;
- Installation of a permanent 50,000m^3/hr TRS in Queanbeyan during 2010/11; and
- Griffith/ Red Hill Secondary Mains Extension in 2014/15.

During 2012/13 and 2013/14, capacity development expenditure is forecast at low levels, only comprised of smaller connection projects in Canberra suburbs. The increase in 2014/15 is related to a secondary interconnection in the Canberra suburb of Griffith.

In summary, the key drivers of forecast capacity developments are organic growth in existing suburbs, new land releases, and infill in Canberra requiring network augmentations to meet capacity requirements.

Table 6.14 provides an overview of the expenditure for the four main capacity development programs.

Table 6.14 Forecast main capacity development projects in 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Tuggeranong Primary Mains Extension	0.1	10.1	0.0	0.0	0.0	10.2
Tuggeranong PRS	0.1	3.0	0.0	0.0	0.0	3.1
Queanbeyan PRS	3.7	0.0	0.0	0.0	0.0	3.7
Griffith/Red Hill Secondary Mains Extension	0.0	0.0	0.0	0.0	1.2	1.2
Total	3.9	13.1	0.0	0.0	1.2	18.3

The projects outlined in the boxes below account for approximately 85 per cent of the proposed capacity development capital program. The first three projects are described in further detail in the engineering assessments in attachment H to this access arrangement information. The remaining capacity development capital expenditure for the access arrangement period is related to smaller identified projects to reinforce the network of the system as greater numbers of customers are being connected.

Box 6.2 Tuggeranong Primary Mains Extension and PRS

The secondary network in Canberra's Tuggeranong district is approaching its designed minimum pressure of 525 kPa during winter. Approximately 27,000 standard cubic metres per hour (scmh) of supply capacity is required in the Tuggeranong network area over the next 20 years to support capacity growth and ensure continuity of supply.

The scope of this work was initially determined through network modelling and followed up by network capacity validation processes to confirm project timing. A new Tuggeranong PRS will consist of a duty run and a standby run which will maintain the supply in the event of a failure of either the duty run or the Phillip PRS. Operation of the Tuggeranong PRS will additionally reduce the load demand on the Phillip PRS.

A 5.7 km primary main extension is required to supply natural gas to the new Tuggeranong PRS. The new primary mains pipeline extension is to be designed to allow for in-line inspection via intelligent pigging.

The total capital expenditure required for the project is $13.3 million and is relevant to Rule 79 (2)(c)(iv). It is estimated that an additional $20,500 (2009/10) per annum will be required from 2013/14 in operational expenditure to maintain the new assets.

The Tuggeranong primary mains extension and PRS project was initially identified in 2004 with an estimated project cost of $3.9 million (2004/05). It was projected at the time that this project would be required by the winter of 2009 assuming a cumulative 8 per cent annual growth in the Tuggeranong network.

Based on actual growth in the Tuggeranong network between 2004 and 2009 and the current forecast of 2 per cent annual growth, it is now projected that this project will be required for the winter of 2012, at an estimated cost of $13.3 million (2009/10).

The major reasons for the increase in estimated cost are:

- The cost estimate is now in 2009/10 terms, rather than 2004/05 terms, during which time there has been an 18.7 per cent increase in the CPI
- The mains extension was based on a 4.1 km main from the Phillip TRS to a site on the corner of Aitkin St. This site is no longer suitable due to residential development in the area. The current project incorporates a longer 5.7 km main which adds $1.2 million to costs
- An 80 per cent real increase in the cost of steel pipe in 2008 (as advised by OneSteel) increases the costs by $0.8 million
- A real increase in the cost of acquiring the PRS due to higher market prices and improved engineering specifications explains $1.1 million

The remaining variance is unexplained, but the current forecast is based on a more rigorous engineering assessment than that carried out in 2004 for a project that was then five years away from forecast requirements.

Box 6.3 Queanbeyan PRS

The main supply to ACT / Queanbeyan Secondary network comes from Watson PRS. A temporary POTS with a design capacity of 5,000 scmh at 1,750 kPa was installed to reinforce supply to the secondary system in the Jerrabomberra area. Jerrabomberra POTS, being temporary and used only during peak winter months, was constructed as a single run without bypass.

Capacity for approximately 30,500 scmh needs to be introduced into the gas distribution networks in Queanbeyan and surrounding areas over the next 20 years to supply demand for the areas of Jerrabomberra, Queanbeyan, Fyshwick, Hume and the proposed new developments at Googong and Tralee.

A new Queanbeyan TRS is proposed to be supplied from the Hoskinstown–Fyshwick trunk main and, along with Fyshwick TRS, will ensure security of gas supply to approximately 25,000 customers in the areas of Jerrabomberra, Queanbeyan, Fyshwick, Hume, and the future proposal developments of Googong and Tralee.

A solution involving the proposed Queanbeyan TRS was initially determined through network modelling and planning and is followed up by network capacity validation processes. The total capital expenditure required for the project is $3.7 million and relevant to Rule 79(2)(c)(iv). It is expected that additional $43,770 ($2009/10) per annum in operational expenditure will be required to maintain the new assets.

This project was included in the earlier access arrangement at a cost of $1.5 million ($2004/05). With the proposed development of the new Googong, Hume and Tralee suburban areas which incorporate over 7,000 dwellings, the scope has changed significantly. The proposed PRS has been replaced by a Trunk Receiving Station in a new location that requires a 2.3 km secondary main extension, not anticipated in 2004.

Box 6.4 Griffith/Red Hill Secondary Mains Extension

Network analysis using the projected average local growth of 2 per cent per annum for South Canberra and surrounding areas indicates that the pressure of the secondary network that feeds the two district regulators in Griffith and Red Hill and would fall below the minimum design pressure of 525 kPa under severe winter conditions. With the forecast pressure below the design minimum, there would be limited capacity to support further network growth or to maintain a reliable supply for medium pressure customers.

The purpose of this project is to provide capacity for growth and supply reliability to customers supplied from the South Canberra medium pressure network in the suburbs of Red Hill, Deakin, Griffith, Narrabundah and Forrest. The capacity upgrade is required to improve the capacity and reliability of supply to handle the growth in the South Canberra region. A 1.8 km 150 mm steel, secondary interconnection in Griffith/Red Hill is therefore required during 2014/15 to provide for future capacity development. The total capital expenditure required for the project is $1.2 million and it is relevant to Rule 79(2)(c)(iv). Further information and maps of this project is available in the Service Plan in attachment Q to this access arrangement information.

6.2.2.3 Stay in business capital expenditure – methodology and forecast

The requirement for stay in business (asset renewal and upgrade) capital expenditure is driven by asset condition, largely driven by age, and compliance requirements relating to safety, reliability and asset protection. Considerations in the process for determining renewal and upgrade requirements are:

- maintaining gas supply and reliability;
- maintaining operational functionality of the network;
- providing a safe work environment for employees and contractors;

- ensuring public safety;
- environmental compliance;
- avoiding property damage; and
- legal and regulatory obligations.

Forecast expenditures are determined with reference to:

- historic trends and the data derived from the GASS system;
- the assessed condition and age of the assets (for example, the reliable operating life of meters);
- assessment of asset failure rates;
- risk management review and prioritisation;
- the requirements of the technical regulator;
- the need to achieve and comply with service and technical standards;
- assessment of health, safety and environmental issues;
- unit rates; and
- escalation of input costs (as described in section 6.2.1.2 above).

Assets are generally replaced either as a result of equipment failure or deteriorating condition indicating imminent failure, rather than by direct reference to age. Meters, on the other hand, are replaced as a result of failure, defect or when the end of their expected life is reached as required by the standards code. Replacement of meters can be deferred after consultation with the technical regulator. Estimates in this access arrangement information are based on an assumption that meters will be replaced on reaching the end of their expected lives. Other asset replacement considerations include the added value that new assets provide through the utilisation of improved technology.

Unit rates have been multiplied by estimated quantities derived from the GASS system or as assessed by engineers. Expenditure for smaller renewal and upgrade capital projects, representing only 9 per cent of costs, has been estimated based on historic cost trends.

The forecast renewal and upgrade capital expenditures for the access arrangement period are set out in Table 6.15.

Table 6.15 Stay in business capital expenditure program 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Facilities Renewal and Upgrade	7.62	0.50	0.34	0.82	0.36	9.65
Mains & Services Renewal and Upgrade	0.03	0.03	0.03	0.05	0.05	0.18
Security of Supply	0.00	50.55	83.73	0.00	0.00	134.28
Residential Meters	0.55	0.83	1.80	1.67	1.78	6.62
I & C Meters	0.69	0.54	1.07	1.22	0.82	4.35
Other	1.43	0.02	0.02	0.02	0.02	1.52
Total stay in business	10.32	52.47	86.99	3.79	3.03	156.60

Stay in business capital expenditure is forecast to increase by $148.7 million compared to the previous five years. This is mainly related to the Hoskinstown to Fyshwick Loop security of supply project of $134.3 million. A significant part of the remaining increase of approximately $14.4 million is related to a small number of projects to be undertaken the beginning of the regulatory period. These include the Fyshwick TRS upgrade (Box 6.5), Canberra Primary Scraper Stations (Box 6.7) and Hoskinstown-Fyshwick Trunk Main Pigging Facilities (Box 6.8) that mainly occur in 2010/11. In 2010/11 capital expenditure of $1.4 million in Other is also included in relation to a multi-utility metering initiative (Project MIMI) as described in Box 6.9. The aged meter replacement program (Box 6.6) will peak in 2012/13. Part of the meter replacement costs in Table 6.15 is an increase for contract meters in 2010/11 of $0.3 million. This is due to the redesign and replacement of turbine meters.

All renewal and upgrade capital expenditure is relevant to Rules 79 (2)(c)(i) – (iii) to maintain and improve the safety and integrity of services and to comply with regulatory obligations and requirements in the access arrangement period.

Table 6.16 presents an overview of the expenditure for the six most significant stay in business capital expenditure projects during the access arrangement period.

Table 6.16 Forecast main stay in business projects in 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Security of supply (HFL)	0.00	50.55	83.73	0.00	0.00	134.28
Fyshwick TRS Upgrade	4.16	0.00	0.00	0.00	0.00	4.16
I&C aged meter replacement	0.54	0.39	0.91	0.97	0.55	3.36
Residential aged gas meter replacement populations	0.08	0.34	0.59	1.55	1.41	3.98
Canberra Primary Scraper Stations	1.69	0.00	0.00	0.00	0.00	1.69
Hoskinstown-Fyshwick Trunk Main Pigging Facilities	1.30	0.00	0.00	0.00	0.00	1.30
Total	7.77	51.28	85.23	2.52	1.96	148.76

The projects in Table 6.16 account for 95 per cent of the proposed renewal and upgrade program. The remaining renewal and upgrade capital expenditure is related mainly to smaller identified mains and services projects, facilities and metering required to maintain the reliability and safety of the system.

The security of supply (HFL) project is discussed in the following section. The other major stay in business projects are summarised in the series of boxes following.

Hoskinstown-Fyshwick Loop

The Hoskinstown-Fyshwick Loop project is a significant investment that will provide additional security in relation to gas supplies to the ACT region during the winter peak. In each of the previous three years (2006, 2007 and 2008), the ActewAGL Distribution gas network has experienced significant threats to security of supply. These have been variously due to operational difficulties experienced at the Moomba gas field and with the main transmission pipelines supplying the network, coupled with peak winter demand in the ACT region.

In June 2006, for example, a combination of factors led to a gas supply shortage in the ACT and Queanbeyan gas network. The Hoskinstown to Fyshwick trunk main, the interconnector between ActewAGL Distribution's network and the Eastern Gas Pipeline designed to provide security of supply and support the system with line pack in peak periods, was required to support the system past the morning peak. The consequence was that packing of the pipeline with gas for the evening peak was unable to commence until after 2.00 pm, leaving insufficient time. Customer losses of supply from this event were limited to voluntary reductions of consumption requested by ActewAGL Distribution.

Another similar event was discussed by the AER in its *State of the Market* report:

> There were significant reliability issues in New South Wales and the ACT from 22 – 24 June 2007 when capacity on the Eastern Gas Pipeline and gas flows on the Moomba to Sydney Pipeline were insufficient to meet higher than expected demand. The distribution network operator was able to manage this issue by loadshedding large industrial and commercial customers, resulting in interruptions to their gas supplies. This enabled gas flows to continue without interruption to smaller retail customers. While there was no underlying infrastructure failure in this instance, the New South Wales Government established a Gas Continuity Scheme in 2008 to mitigate the risk of a recurrence. The scheme will provide commercial incentives for producers to increase supplies and customers to reduce gas usage in the event of a shortfall event. [66]

Incidents such as these described, while not attributable directly to the management, operation or capacity of the ActewAGL Distribution gas network, pose significant risk to security of gas supply in the ACT. Moreover, the nature of the ACT market is such that there are no large industrial customers from which load can be shed in such circumstances. Going forward, as winter peak demand in the ACT increases further, the potential for interruptions to gas supply in ActewAGL Distribution's network is likely to increase.

[66] AER 2008, State of the Energy Market 2008, December, p 286 ActewAGL notes that the Gas Continuity Scheme does not operate in the ACT and there is no similar government scheme to provide incentives for small and large users to reduce gas usage in the event of a shortfall in the ACT.

Given the supply reliability concerns in relation to the integrity of gas supply services, ActewAGL Distribution has been actively considering alternative options to ensure that supply to the ACT can be maintained during upstream supply events and higher than anticipated local demand. Following the most recent events in 2008, the ACT Chief Minister wrote to ActewAGL requesting that it examine as a matter of high priority what is in its power to do, to provide greater security of gas supply to the ACT and the region.

Security of gas supply in the ACT region

The ACT market is characterised by a significant peak in demand in winter that far exceeds demand in summer, and by the fact that it is predominantly a residential tariff market, with a very low proportion of commercial customers. Both of these factors raise challenges in relation to ensuring the security of gas supply.

The current gas distribution network configuration provides for approximately 8 TJ of gas storage capacity. This provides the equivalent of just one hour of gas contingency during the winter peak period, before residential customers' supply would need to be managed down on a large scale.

Significant winter peak load

Winter peak demand on ActewAGL Distribution's network has been around 70 TJ/day in recent years, compared to just 7 TJ/day in summer. That is, demand in winter increases by a factor of ten.

This substantial level of demand is met by gas deliveries from both the MSP and the EGP. Supply to the ACT from Moomba at Watson (from the MSP) is restricted, by the current pressure on the MSP, to 56 TJ/day. The difference between this and the total ACT winter demand requirement is therefore currently made up by supplies from the EGP.

Current lack of security of supply threatens residential load

Contract load on the ActewAGL Distribution network accounts for only around 2 TJ/day of overall demand, that is, less than 3 per cent of total winter peak demand. This demand is divided between 40 contract customers. Domestic and small commercial customers on tariff arrangements make up the vast majority of demand.

One important consequence of this is that the options for curtailing demand in the event of a disruption to gas supplies are extremely limited compared with other networks. Specifically, following a threat to the security of supply, there is very limited opportunity for ActewAGL Distribution to obtain a significant demand reduction from load-shedding by contract customers since their overall demand forms such a low proportion of overall peak demand in winter. On other networks, curtailing selected commercial and/or industrial customers can result in a much more significant reduction in demand, more likely to be sufficient to maintain security of supply in the event of a supply disruption.

In the event of a security of supply threat to the ACT, ActewAGL Distribution would need to very quickly move to curtail residential consumption in the mass market. The first step would be to seek voluntary reductions in residential load. However, ActewAGL Distribution's experience in previously seeking such voluntary reductions is that the response that can be obtained from residential customers in the necessarily short timeframes is very low due, for example, to the absence of many from their homes. The next step would be to move straight to disconnection of residential customers, in accordance with ActewAGL Distribution's Contingency Plan. Such a step would obviously be highly unpopular and would cause disruption and potential hardship to a large number of residential customers. For example, under the current version of the Contingency Plan up to 56,500 customers could lose their supply in winter, within one hour of a supply disruption at Watson. In this event, the disruption would be expected weeks to months as supply is progressively reinstated. Such disruption would also be extremely costly for ActewAGL Distribution and its customers, as the process of disconnection and reconnection is one that requires significant labour resources and time and a period of non-supply.

Recent experience

Separate incidents relating to the security of supply of gas to the ACT and Queanbeyan occurred in 2006, 2007 and again in 2008. These events varied in nature and included transmission pipeline infrastructure issues, gas field interruptions and capacity contracting issues on the transmission pipelines supplying the ACT. These events highlight that the ActewAGL Distribution is reliant on upstream producers, shippers and pipeline operators to maintain supply, and that the risk decisions these players make have the potential to impact supplies to ACT households. The possibility of a sizeable gas outage during a Canberra winter, and the consequences that this would have in terms of the need to disconnect many thousands of residential customers, presents a significant on-going concern to ActewAGL Distribution.

The risks will amplify going forward as additional demand growth is realised. In addition, there is expected to be less transparency in relation to shippers' nominations on the upstream pipelines as a result of the introduction of the STTM Sydney Hub (expected from 1 July 2010) at the end of the ACT supply chain. ActewAGL Distribution considers that this development could lessen the already short lead-time for it becoming aware of a possible security of supply event due to retailer under-nomination.

Following the most recent threat to security of supply in 2008, the ACT Chief Minister wrote to ActewAGL requesting that it examine as a matter of high priority options in its power to provide greater security of gas supply to the ACT and the region.

Options for improving security of supply

In October 2007, a study was completed for ActewAGL Distribution on security of supply options for the ACT/Queanbeyan gas distribution network. This study focused on alternative network looping options to enhance the capability to store gas as a contingency to address upstream supply disruptions.

The four options considered are summarised below:

1. **Primary Loop.** Primary loop on ActewAGL's network from Belconnen, across the Molonglo Valley to Phillip. Approximately 20 km.
2. **Dalton to Watson Loop**. This option would entail the installation of a compressor by MSP to enable greater supply capacity from the MSP, plus looping of the MSP between Dalton and Watson, in order to provide additional storage capacity.
3. **Hoskinstown – Fyshwick loop.** Looping of ActewAGL's network between Hoskinstown and Fyshwick, by installing a 42 inch (1050mm) gas pipeline from the Hoskinstown Station to the NSW border, paralleling the existing 10 inch Hoskinstown to Fyshwick interconnection.
4. **Hoskinstown – Fyshwick Loop and Primary Loop.** A combination of options 1 and 3 above.

These four options were presented to the ActewAGL Joint Venture Board in October 2007 and option 4 was identified as the most appropriate, on the basis of the likely cost per TJ of capacity gained and that it is an option within ActewAGL's control. The HFL is the first stage of this development. The Dalton to Watson loop (option 2) would be likely to cost a similar amount to the HFL, but would provide less storage capacity, since the MSP is operated at a lower pressure than ActewAGL's network at Hoskinstown. This option would also require investment by the APA Group (owner of the MSP) and is therefore not within the control of ActewAGL Distribution.

A subsequent in-depth technical analysis of the HFL was undertaken in order to confirm capacity requirements. The details of the planned HFL development are set out in the following section.

A further alternative to the looping options presented above which has been considered is the *parking* of gas by ActewAGL Distribution, as a contingency measure. Under this scenario, ActewAGL Distribution would enter into a contract with either the EGP or MSP for additional 'own-use' gas which it would then *park* in the pipeline to have available to supply the ACT. In practice, capacity on the EGP is currently fully contracted, which means that ActewAGL would most probably need to obtain gas from the MSP. Given that the delivery point for the MSP at Walton is already at capacity, this option would need to also involve the installation of a compressor on the MSP at Dalton. This investment is outside ActewAGL Distribution's control. This option would also put ActewAGL in a potential trading role, outside of the scope of ActewAGL Distribution's current activities. For these reasons, the option of ActewAGL parking gas to ensure security of supply is not considered to be viable.

The Planned HFL

The primary function of the proposed HFL is to provide contingency supply to the ACT in the event of a supply imbalance or shortage upstream of the network. Specifically, the HFL project will increase the length of time that the ACT network can withstand an upstream disruption to supply during the winter peak from 1 hour to 16 hours. As a result, the HFL will increase the flexibility of the network in accommodating fluctuations in demand and unexpected upstream disruptions.

ActewAGL Distribution considers that the capital expenditure associated with the HFL project is conforming capital expenditure, in line with NGR 79(1). As it is necessary to maintain the integrity of services, the capital expenditure is justifiable in line with Rule 79(2)(c)(ii).

JAM has undertaken a feasibility study on the HFL at the request of ActewAGL Distribution. The feasibility study identified two options which were then further investigated:

- **Option A**: 21 km of 42 inch pipe from Hoskinstown Station to within a kilometre of the NSW/ACT border near Queanbeyan. Option A provides 88 TJ storage at an estimated cost of $130 million, that is, a price/TJ of $1,477,273
- **Option B:** consists of 16.5 km of 42 inch pipe from Hoskinstown Station and stopping on the east of the first Captains Flat road crossing. Option B provides 66 TJ storage at an estimated cost of $95 million, that is, a price/TJ of $1,439,394

Given that the cost per TJ of the two options is very similar, ActewAGL has decided to undertake Option A, on the basis of the greater degree of security that this option will provide. The $130m cost of Option A has therefore been incorporated into ActewAGL Distribution's capital expenditure forecasts for the forthcoming access arrangement period.

The next steps in relation to this project will be the detailed design process plus the procurement process for the long lead items (principally the 42 inch valves, pipe and induction bends).

ActewAGL notes that the HFL is Stage 1 of the option for improving security of supply. Stage 2 consists of looping the Canberra primary main. It is envisaged that Stage 2 will be developed in conjunction with expansion of suburban development through the Molonglo Valley, over the next five to ten years. No expenditure associated with Stage 2 has been incorporated in the expenditure projections for the access arrangement period. Documents relating to the development of the HFL can be found at attachment H.

Box 6.5 Fyshwick TRS Upgrade

The Fyshwick TRS facility was built in 2000/01 to facilitate the top up operation of the Canberra Primary Main as well as to pack gas back into the Hoskinstown to Fyshwick trunk main via the bypass line as required.

Fyshwick TRS currently has a design capacity of 42,000 scmh at minimum inlet pressure of 3000 kPa. The current station configuration with a single active run does not allow for effective equipment availability for maintenance work. The risk factor of this inflexibility increases during the peak winter months when the station is in continuous operation. A failure of the Fyshwick TRS during the winter months could potentially affect the entire Canberra Network.

The proposed upgrade of the Fyshwick TRS will enable the maintenance of equipment as a result of having two / three runs and two water bath heaters. These make the equipment accessible and available. It will also allow highest security of supply at low inlet pressure. An increased station capacity will also mitigate a failure of Hoskinstown CTS. The total capital expenditure required for the project is $4.2 million and it is related to Rule 79 (2)(c)(i) - (ii), integrity and safety. Further information is available in the engineering assessment in attachment H to this access arrangement information.

Box 6.6 I&C and Residential aged gas meter replacement programs

The Industrial & Commercial and Residential aged meter replacements programs are intended to secure the integrity and compliance of the meters. The meters subject to the program are those reaching their maximum regulatory and economic service life, as sourced from GASS data. The unit rate for the Industrial and Commercial aged meter replacement program is averaged and variable across the meter population , while the unit rate for residential meters is fixed (subject only to escalation). The number of meters to be replaced during the access arrangement period is summarised in the table below. The total capital expenditure required for these programs is $7.3 million and they are related to Rule 79 (2)(c)(ii) – (iii), integrity and regulatory obligation requirements.

Industrial & Commercial aged meters to be replaced

	2010/11	2011/12	2012/13	2013/14	2014/15
I&C Meters	84	112	244	189	134
Residential Meters	1,500	2,515	6,272	5,438	5,595

Box 6.7 Canberra Primary Main Scraper Stations

The ActewAGL DN250 Canberra Primary Main was built in stages from 1995 to 2006 to provide for the safe and reliable supply of Natural Gas to Canberra and the Southern ACT distribution network. While the pipeline has been designed to be piggable, no Canberra stations currently have facilities to perform in-line inspections.

The Canberra Primary Main contains sections of pipeline that have been in service for more than 10 years without review of its MAOP. As a requirement of AS2885.3, the pipeline's MAOP must be confirmed after 10 years in operation by establishing the condition of the pipe wall on a minimum of five year intervals.

Canberra Primary Main Integrity project, which is described further in chapter 9, will facilitate data collection as a key input to confirm the MAOP of the Canberra Primary Main for the next pipeline review due in 2011.

The inline inspection option requires the Canberra Primary Main Scraper Stations project to proceed. This project involves the installation of pig launchers and receivers on the primary main. The installation of permanent and temporary facilities will provide the stations required to perform the in-line inspection of the Canberra Primary Main from Gungahlin PRS to Phillip PRS. The total capital expenditure required for this project is $1.7 million and they are relevant to Rule 79 (2)(c)(ii) - (iii), integrity and regulatory obligation requirements. Further information about the Canberra Primary Scraper Stations is provided in the engineering assessment in attachment H to this access arrangement information.

Box 6.8 Hoskinstown-Fyshwick Trunk Pigging Facilities

This project is similar to the Canberra Main Scraper Stations described in Box 6.7. The Hoskinstown-Fyshwick Trunk Pigging Facilities project has been independently assessed due to different operational environment.

The Hoskinstown to Fyshwick trunk main was fully constructed and commissioned during 2000 and 2001. The Hoskinstown-Fyshwick Trunk Main Integrity project is described in chapter 9 and intends to develop an inspection program to confirm the MAOP of the Hoskinstown to Fyshwick trunk main. The next pipeline review is due in 2011. The Main integrity project requires either permanent or temporary pig launcher and receiver facilities to be installed.

Hoskinstown-Fyshwick pigging facilities project comprises a permanent pig launcher to be installed at Hoskinstown CTS and a permanent pig receiver at Fyshwick TRS. The pigging facilities will be designed to class 900 as per the existing facilities. Based upon a requirement for the in-line inspection during April 2011, the launcher / receiver would be required to be completed by end of 2010 to provide time for contingency and confirmation of in-line inspection test. The total capital expenditure required for this project is $1.3 million and they are relevant to Rule 79 (2)(c)(ii) - (iii), integrity and regulatory obligation requirements. Further information about this project is provided in the engineering assessment in attachment H to this access arrangement information.

Box 6.9 Project MIMI

The multi-utility metering initiative (Project MIMI) will investigate opportunities for remotely read, multi-utility metering. It is expected to deliver recommendations on the technology options best suited to ACTEW Corporation and ActewAGL Distribution, report the expected costs and savings in a business case, report on market acceptance and customer behavioural responses, and identify any change management and communication challenges in a full deployment of smart meters across the ACT.

The total cost of the Project MIMI is $7 million (2006/07). Recognising the ACT Government announcement in October 2007, the ICRC in its April 2008 Final Decision for ACTEW Corporation suggested cost recovery for Project MIMI on a 40:40:20 basis. That is, 40 per cent electricity, 40 per cent water, and 20 per cent gas. On this basis the ICRC made an expenditure provision for ACTEW Corporation of $2.8 million in expenditure for Project MIMI in 2008/09. The capital expenditure for ActewAGL Distribution's electricity network was also recognised and discussed by the AER in its November 2008 Draft decision and included in the capital expenditure allowance in the final decision in April 2009.

ActewAGL Distribution therefore proposes, consistent with the ICRC's decision for ACTEW Corporation and the AER decision for ActewAGL Distribution Electricity Network, that the AER allow the recovery of the $1.4 million (2006/07) in expenditures for the 'gas portion' of Project MIMI in 2010/11.

6.2.2.4 Non system assets capital expenditure – methodology and forecast

Non system assets capital expenditure consists of only GIS Network system expenditure. The forecast non system assets capital expenditures for the access arrangement period are set out in Table 6.17.

Table 6.17 Non system assets capital expenditure program 2011-15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
IT System	0.32	0.31	0.45	0.10	0.00	1.18
Total non system assets capital expenditure	0.32	0.31	0.45	0.10	0.00	1.18

Regulatory costs, capitalised in the earlier access arrangement period, will be expensed in the next regulatory period consistent with ActewAGL Distribution's capitalisation policy. This approach is also consistent with that determined in the AER's April 2009 final decision for ActewAGL Distribution's electricity distribution network.

In order to achieve potential cost reductions over the longer term, a program of works has been designed to upgrade the GIS. ActewAGL Distribution contracts these services to Ecowise Environmental (Ecowise) and has engaged with Ecowise for development and provision of upgraded GIS services.

The proposed GIS capital project has been developed by Ecowise, ActewAGL Distribution's GIS services contractor. The project will provide improvements in the reliability, safety and security of the gas network by providing more complete, accurate and timely data from which improved information and reporting products can be derived and disseminated. This will result in greater visibility and a more complete understanding of the network.

A well designed GIS solution, utilising complete and accurate data can readily provide significant business benefit and improvement opportunity across a range of core business functions including, network performance, supply, outage management, customer management, network planning and design.

6.2.3 Non-conforming capital expenditure

Rule 81 recognises the possibility of a service provider choosing to undertake certain capital expenditure non-conforming in whole or part. Subsequent Rules 82 to 84 stipulate means by which the cost of non-conforming capital expenditure can be recovered. These are:

- capital contributions by users of new capital expenditure (rule 82);
- surcharges (rule 83); and
- a speculative capital expenditure account (rule 84).

6.2.3.1 Capital contributions

During the earlier access arrangement period, ActewAGL Distribution received capital contributions in the *medium pressure services* and *Industrial & commercial meters* asset classes and a single capital contribution for *medium pressure mains* in 2007/08 (described below).

Capital contributions received in the earlier access arrangement period are summarised in Table 6.18.

Table 6.18 Capital contributions 2004/05 to 2009/10

$ '000 (2009/10)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
MP Services	0.06	0.08	0.12	0.03	0.11	0.05	0.46
Medium pressure mains	0.00	0.00	0.00	1.08	0.00	0.00	1.08
Meters – Commercial and Industrial	0.00	0.00	0.01	0.06	0.01	0.00	0.09
Total capital contributions	0.07	0.08	0.13	1.18	0.12	0.05	1.63

To estimate the capital contributions for the access arrangement period, ActewAGL Distribution has applied the historic percentage on the forecast capital expenditure. The one off capital contributions in medium pressure mains in 2007/08 was a new main feeder line to a large customer in Bungendore. This project was deemed uneconomic and the full contribution was paid. The forecast capital contributions for the access arrangement period is summarised in Table 6.19.

Table 6.19 Capital contributions 2009/10 to 2014/15

$ '000 (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
MP Services	0.05	0.05	0.06	0.06	0.06	0.27
Meters – Commercial and Industrial	0.00	0.00	0.00	0.00	0.00	0.02
Total capital contributions	0.05	0.06	0.06	0.06	0.06	0.29

Rule 82 deals with the possibility of capital contributions by users of new capital expenditure. ActewAGL Distribution applies the provisions of the ACT *Gas Networks Capital Contribution Code* (August 2007) under the *Utilities Act 2000* (ACT), which states that:

> A Gas Distributor or a Gas Supplier may charge, and a Customer must pay, a Capital Contribution Charge for the development or augmentation of its Gas Network undertaken to provide Utility Services to a Customer.

Rule 82(2) stipulates that a capital contribution may, with the approval of the AER, be rolled into the service provider's capital base, provided that there is a mechanism in place to ensure that no part of the capital expenditure contributed by users benefits the service provider through increased revenue.

ActewAGL Distribution does not propose to roll the value of capital contributed by users into the capital base. Furthermore, ActewAGL Distribution does not have or propose the required mechanism to do so. Consequently, all capital contributions past and forecast are excluded from the capital base of this access arrangement information. In other words, the net capital expenditure rolled into the capital based is gross capital expenditure minus capital that has been contributed.

6.2.3.2 Disposals

ActewAGL Distribution will not dispose of assets during the earlier access arrangement period and forecasts no redundant capital during the access arrangement period. As all of ActewAGL Distribution's vehicles and computers are leased, ActewAGL Distribution does not expect any cash disposals in the access arrangement period starting 2009/10. When meters are defective, they will be scrapped, but that does not provide ActewAGL Distribution with a cash disposal. Because the amount is insignificant, ActewAGL Distribution has not sought to write these off in its regulatory accounts, but has assumed that any residual value for which a write down would occur will occur as depreciation of the remaining value in the capital base.

ActewAGL Distribution also notes that corporate capital expenditure has not been included in the capital base. The sale of the ActewAGL corporate headquarters in 2008 does not affect gas networks capital base.

6.2.3.3 Proposed surcharges

A surcharge under rule 83 is defined by sub-rule (2) as a charge, approved by the AER, in addition to a reference tariff (or other tariff):

- to be levied on users of incremental services; and
- designed to recover non-conforming capital expenditure or a specified portion of non-conforming capital expenditure.

ActewAGL Distribution does not expect any non-conforming capital expenditure in the access arrangement period and is therefore not proposing any surcharges under this rule.

6.2.3.4 Speculative capital expenditure account

Rule 84 provides that non-conforming capital expenditure can be held (to the extent that it is not recovered via a surcharge or capital contribution) in a notional fund, the balance of which the AER can allow to increase at the rate of return implicit in the reference tariff, or an alternative rate of return, at the AER’s discretion.

ActewAGL Distribution does not have a speculative investment fund under the Gas Code and does not expect to incur speculative capital expenditure during the access arrangement period.

6.2.4 Equity raising costs

When raising equity, a company incurs costs such as brokerage fees, legal fees, marketing and registration costs with the stock exchange and other transaction costs. These are upfront expenses for raising the equity. After the equity has been raised, companies have very limited (if any) costs associated with the raised capital. Companies may raise equity at different times; when the company is founded, to fund major investments, to fund acquisitions or mergers or to overcome financial stress.

The AER has accepted equity raising costs as a legitimate cost for a benchmark efficient firm when external equity funding is the least-cost option available. When cheaper sources of funding, such as retained earnings are insufficient, the AER has provided an allowance for equity raising costs. This has been subject to gearing ratio and other assumptions about financing decisions being consistent with a regulatory benchmark.

The benchmark equity raising cost model was recently adjusted by the AER in connection with the final decision for the NSW and ACT electricity distribution businesses in April 2009. The model allows the companies compensation for direct equity raising costs and considers that the benchmark cost for an efficient company is 2.75 per cent. In addition, the model also allows a compensation for payment of debt principal for maintaining the assumed gearing ratio and the payout of dividends in order to value imputation credits.

ActewAGL Distribution has for the access arrangement period used the benchmark equity raising model cash flow developed by the AER for the final decision in April 2009 for the NSW and ACT electricity distribution businesses.

A summary of ActewAGL Distribution’s benchmark equity raising costs is set out in Table 6.20.

Table 6.20 Benchmark equity raising costs

$ m (nominal)	ActewAGL Distribution proposal	Comment
Dividends	38.0	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	11.4	30 per cent of dividends paid
Cost of dividend reinvestment plan	0.11	Dividends reinvested multiplied by benchmark cost (1 per cent)
Capital expenditure funding requirement	223.6	Forecast capital expenditure funding requirement (not the capital expenditure value that includes a half year WACC adjustment)
Debt component	127.5	Set to equal 60 per cent of the capital base increase (not capital expenditure)
Equity component	96.1	Residual capital expenditure funding requirement less the debt component
Retained cash flows available for reinvestment	80.6	Includes dividends reinvested
External equity requirement	15.5	Equal to equity component less retained cash flows
External equity raising cost	0.43	External equity requirement multiplied by benchmark direct cost (2.75 per cent)
Total	0.55	Sum of dividend reinvestment plan and external equity raising cost

The equity raising cost is a result of the large increase in proposed capital expenditure. ActewAGL Distribution proposes that the cost should be capitalised and amortised over the life of ActewAGL Distribution’s capital base.

6.3 Summary of forecast capital expenditure in the access arrangement period

Table 6.21 summarises the total proposed capital expenditure program, outlined in the previous sections, for the access arrangement period.

Table 6.21 Forecast capital expenditure including contributions and disposals 2010–15

$ million (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Distribution system capital expenditure						
Market expansion	8.78	7.13	7.07	6.23	5.88	35.09
Capacity development	4.81	13.64	0.68	0.32	2.12	21.57
Stay in business	10.32	52.47	86.99	3.79	3.03	156.60
Total distribution system capital expenditure	23.91	73.24	94.74	10.34	11.03	213.26
Non-system capital expenditure						
IT System	0.32	0.31	0.45	0.10	0.00	1.18
Total non system capital expenditure	0.32	0.31	0.45	0.10	0.00	1.18
Capital contributions	-0.05	-0.06	-0.06	-0.06	-0.06	-0.29
Equity raising costs	0.55	0	0	0	0	0.55
Disposals	0	0	0	0	0	0
Total capital expenditure	**24.72**	**73.50**	**95.13**	**10.37**	**10.97**	**214.69**

7 Capital base

This chapter of the access arrangement information outlines the derivation of the opening capital base of the ActewAGL Distribution gas network from which a return on and of capital are calculated.

7.1 Opening capital base for the access arrangement period

Rule 72(1)(b) requires access arrangement information to include:

> … how the capital base is arrived at and … a demonstration of how the capital base increased or diminished over the previous access arrangement period.

The procedure for rolling forward a capital base from one access arrangement period is laid down in Rule 77(2). This specifies that;

> If an access arrangement period follows immediately on the conclusion of a preceding access arrangement period, the opening capital base for the later access arrangement period is to be:
>
> (a) the opening capital base as at the commencement of the earlier access arrangement period (adjusted for any difference between estimated and actual capital expenditure incurred in that opening capital base); plus
>
> (b) conforming capital expenditure made, or to be made, during the earlier access arrangement period; plus
>
> (c) any amounts to be added to the capital base under rule 82 [capital contributions], 84 [speculative capital expenditure account] or 86 [re-use of redundant assets]; less
>
> (d) depreciation over the earlier access arrangement period (to be calculated in accordance with any earlier determination or regulatory decision governing the calculation of depreciation for the purpose of establishing the opening capital base); and
>
> redundant assets identified during the course of the earlier access arrangement period; and
>
> the value of pipeline assets disposed of during the earlier access arrangement period.

This procedure, as relevant to the calculation of the opening capital base for ActewAGL Distribution's ACT, Queanbeyan and Palerang gas distribution network, is discussed in the following sections. The required demonstration of the increase of the capital base over the earlier access arrangement period is provided at section 7.1.6 below.

7.1.1 Opening capital base for the earlier access arrangement period

The capital base approved by the ICRC for ActewAGL Distribution's gas network at 1 July 2003 was \$219.6 million and at 1 July 2004 \$225.9 million (both in nominal terms).[67] Table

[67] ActewAGL Distribution, Access Arrangement Information ActewAGL Gas distribution system in ACT and Greater Queanbeyan, November 2004, table 3.1, p 5

7.1 provides a breakdown of these opening capital base values by asset class. These are consistent with the model used in the earlier access arrangement period provided in attachment 0 to this access arrangement information.

Table 7.1 Opening capital base in the earlier access arrangement period by asset class

	Opening capital base in the earlier access arrangement period($ nominal)		Capital base ($ nominal) after adjustment for actual capex in 2003/04
Asset class	1 July 2003	1 July 2004	1 July 2004
Primary (HP) Mains	49.0	51.4	51.4
HP Services	0.8	0.8	0.8
MP Mains	124.4	125.1	125.5
MP Services	36.7	40.6	39.6
Regulators, Valves (TRS, SRS)	3.5	3.5	3.6
Contract meters	0.6	0.5	0.5
Tariff meters	4.5	3.9	4.4
Non System Assets	-	-	-
IT System	-	-	-
Regulatory costs	-	-	-
Total Capital base	219.6	225.9	225.9

The capital base at 1 July 2004 requires adjustment for variations between capital expenditure at the end of previous access arrangement period estimated at the time of the final decision and actual capital expenditure. There is only a small variation in capital expenditure of $0.1 million from the forecast in the final year of the previous access arrangement period (2003/2004). This was the result of higher expenditures for meters and medium pressure mains, but lower expenditure for medium pressure services, than in the original forecast.

The opening capital value for each asset class as at 1 July 2004 has been adjusted for this difference. No other adjustments are required to the opening capital base for the earlier access arrangement period. ActewAGL Distribution has also calculated the real return in accordance with the determined WACC of 7.0 per cent in the earlier access arrangement period and adjusted it for actual inflation. At the end of 2009/10, the total return on the difference between actual and forecast capital expenditure in 2003/04 equals $0.1 million. This has been added to the value of opening capital base (see Table 7.3 below) proportional to the difference between actual and forecast capital expenditure in 2003/04. The mechanism for this is included in the Roll Forward Model (RFM) provided at attachment R to this access arrangement information.

The calculated remaining asset lives reflected the capital base as at 1 July 2004 are included in the RFM. ActewAGL Distribution has not calculated the opening remaining life values between the determinations (2006-2009 and 2011-2015) since they are not required in the principal calculation. These can be calculated in both the RFM and the Post Tax Revenue Model (PTRM) using assumptions external to the models.

ActewAGL Distribution is not aware of any final determination with regard to remaining asset lives as at 30 June 2004. ActewAGL Distribution has applied a consistent method to remaining asset lives since 1999-2000. Asset classes used in the earlier access arrangement are identical to those in the access arrangement.

7.1.2 Conforming capital expenditure during the 2004–10 period

Conforming capital expenditure for the earlier access arrangement period is described and analysed in Chapter 6 of this access arrangement information and is summarised in Table 6.21. As discussed in chapter 6, ActewAGL Distribution considers its capital expenditure in the earlier access arrangement period to be prudent and efficient. The ICRC allowance for the earlier access arrangement period is expected to be underspent by $0.7 million as a result of prudent deferrals of meter replacement, and of capacity development projects due to lower than determined demand.

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

7.1.3.1 Capital contributions

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

Capital contributions incurred in the earlier access arrangement period are described in section 6.2.3.1. ActewAGL Distribution has not and does not propose to roll into the capital base any capital expenditure funded by a capital contribution.

7.1.3.2 Speculative capital expenditure account

Rule 84(3) allows for a portion of a *speculative capital expenditure account*, created for non-conforming capital expenditure, to be withdrawn from the account and rolled into the capital base at the commencement of the next access arrangement period.

ActewAGL does not have a speculative capital expenditure account and therefore the opening capital base for the access arrangement period will not incorporate amounts from such an account.

7.1.3.3 Re-use of redundant assets

Rule 86 allows, subject to the new capital expenditure criteria, for the re-instatement to the capital base of assets previously identified as redundant, but which later contribute to the delivery of pipeline services.

No ActewAGL Distribution gas network assets have been classed as redundant and therefore no addition to the capital base is possible for re-use of redundant assets.

7.1.3.4 Redundant assets identified during the earlier access arrangement period

Clauses 4.6 and 4.7 of the access arrangement in the earlier access arrangement specify a capital redundancy mechanism in accordance with clause 8.27 of the Gas Code. Such a mechanism in a transitional access arrangement is taken to be a corresponding mechanism under the transitional provisions of the NGR.[68]

According to the earlier access arrangement, the relevant regulator may reduce the capital base with effect from the commencement date (of the later access arrangement) by an amount representing:

> (a) any assets that in the reasonable opinion of the Relevant Regulator have ceased to contribute to the delivery of Services;
>
> (b) any assets that have been transferred by ActewAGL or in relation to which ActewAGL has entered into a binding agreement for its transfer; or
>
> (c) any assets that in the reasonable opinion of the Relevant Regulator have decreased in value because of a decrease in its utilisation resulting from a decline in the volume of sales of the Service.

ActewAGL Distribution considers that none of its assets meets any of these three criteria, and therefore no assets need to be removed from the opening capital base under this provision.

7.1.3.5 Asset disposals during the earlier access arrangement period

The earlier access arrangement included an amount of approximately $0.05 million per annum for asset disposals of meters. This was a reasonable estimate at the time of the proposal for the value of defective and unserviceable meters during the earlier access arrangement. No disposals with cash effects have however been recorded during the earlier access arrangement period. As stated in the capital expenditure chapter, ActewAGL Distribution does not own any vehicles, computers or other assets that have been disposed. ActewAGL Distribution notes that its corporate headquarters was disposed during the earlier access arrangement period, but since it was never included in the capital base, the disposal does not affect the capital base.

7.1.4 Depreciation during the earlier access arrangement period

Rule 77(2)(d) includes that depreciation over the earlier access arrangement period is:

> … to be calculated in accordance with any relevant provisions of the access arrangement governing the calculation of depreciation for the purpose of establishing the opening capital base.

Following review of the access arrangement for the earlier access arrangement, ActewAGL Distribution is not aware of any provisions of the earlier access arrangement specifying the intended approach to the calculation of depreciation when determining the opening asset base at 1 July 2010. This is consistent with the fact that the current access arrangement

[68] NGR, Schedule 1, clause 3(13)

was made under the Gas Code which did not include any requirements similar to Rule 90 requiring a provision in an access arrangement specifying the means of calculating depreciation for rolling forward capital base from one access arrangement period to the next.

ActewAGL Distribution proposes to determine the opening asset base at 1 July 2010 by applying the same approach as was adopted for the 1 July 2004 roll forward. In its 2004 Final Decision for the earlier access arrangement period, the ICRC noted that ActewAGL Distribution's opening capital base was based on "… the regulatory depreciation determined during the 2001 access arrangement period".[69]

The 2004 Final Decision also states that, in the final year of the previous regulatory period (that is, 1999/2000) depreciation was calculated from "… the actual level of capital expenditure, rather than on the depreciation forecast made in 2000".[70]

The regulatory model used to determine regulatory revenues in the earlier access arrangement period applied a depreciation schedule based on actual rather than forecast depreciation; that is, the roll forward depreciation schedule was calculated using actual rather than forecast capital expenditure.[71]

The depreciation schedule for the earlier access arrangement period is set out in Table 7.2.

Table 7.2 ActewAGL Distribution capital expenditure and depreciation roll-forward 2005-2010

$'000 nominal	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10	Total
Actual net capital expenditure	9.8	7.2	11.1	7.6	8.7	15.6	*60.0*
Depreciation	7.3	8.0	8,6	8.4	8.7	9.2	50.4

Depreciation by asset class, assigned standard life and remaining life are provided in the RFM at attachment R to this access arrangement information. All asset classes and standard life values used are consistent with the RFM used by the ICRC in the earlier access arrangement period.

7.1.5 Indexation of the capital base

ActewAGL Distribution has indexed its capital base for actual inflation for during 2003/04 to 2007/08 and used the RBA's inflation forecast[72] for 2008/09 and 2009/10. The resulting value for capital base indexation is presented in Table 7.3 and in the RFM at attachment 0 to this access arrangement information.

[69] ICRC, Final Decision: Review of access arrangements for ActewAGL Distribution natural gas access system in ACT< Queanbeyan and Yarrowlumla, p. 107.
[70] ICRC, Final Decision: Review of access arrangements for ActewAGL Distribution natural gas access system in ACT< Queanbeyan and Yarrowlumla, p. 108.
[71] The regulatory model is labelled "1 Final Gas Networks Access Arrangement model 7 October". This model can be provided upon request.
[72] RBA Monetary Policy, May 2009

7.1.6 Opening capital base in 2010

Combining the elements of the previous sections, including the opening capital base value as at 1 July 2003 of $219.6 million, and actual capital expenditure from the earlier access arrangement period from chapter 6, ActewAGL Distribution has rolled forward the capital base for the earlier access arrangement consistent with the methodology adopted by the ICRC to calculate the opening capital base at the commencement of the access arrangement period staring 1 July 2010.

The required demonstration of the increase in the ActewAGL Distribution gas network business capital base and rolled forward value of the capital base as at 30 June 2010 of $278.3 million are provided in Table 7.3.

Information of the capital base by asset class is provided in the Roll Forward Model in attachment 0 to this access arrangement information.

Table 7.3 Derivation of the opening capital base at 1 July 2010

$ million (nominal)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Opening capital base	**225.9**	**234.1**	**242.7**	**250.4**	**261.0**	**265.0**	**278.3**
plus Capital expenditure	9.8	7.2	11.1	7.6	8.7	15.6	
plus Speculative capital expenditure	-	-	-	-	-	-	
plus Re-used redundant assets	-	-	-	-	-	-	
less Depreciation	7.3	8.0	8.6	8.4	8.7	9.2	
less Redundant assets	-	-	-	-	-	-	
less Disposals	-	-	-	-	-	-	
plus Indexation	5.7	9.5	5.1	11.5	4.0	6.8	
Closing capital base	**234.1**	**242.7**	**250.4**	**261.0**	**265.0**	**278.2**	
Adjustment to opening value						0.1	

Source: Roll Forward Model

7.2 Projected capital base over the access arrangement period

Rule 72(1)(c) requires access arrangement information to include:

> … the projected capital base over the access arrangement period, including;
>
> (i) a forecast of conforming capital expenditure for the period and the justification for the forecast; and
>
> (ii) a forecast of depreciation for the period including a demonstration of how the forecast is justified on the basis of the proposed depreciation method.

Rule 78 specifies that:

> The projected capital base for a particular period is:

(a) the opening capital base; plus:

(b) forecast conforming capital expenditure for the period; less:

(c) forecast depreciation for the period; and

(d) the forecast value of pipeline assets to be disposed on in the course of the period.

The elements of the projected capital base, reflecting the requirements of Rule 78, are discussed below.

7.2.1 Opening capital base for 2010/11

The opening capital base for the access arrangement period, $278.3 million, is that derived in Table 7.3 of this access arrangement information.

7.2.2 Forecast capital expenditure

ActewAGL Distribution has rolled forward the opening capital base for the access arrangement period using the forecast of conforming net capital expenditure derived in Chapter 6 of this access arrangement information.

7.2.2.1 Non-conforming capital expenditure

Rule 81 allows a service provider to make capital expenditure that is in whole or part non-conforming and in certain cases to be recovered through a surcharge on specific customers (under Rule 83), or to form a speculative capital expenditure account (under Rule 84) and in specified circumstances later re-enter the capital base.

ActewAGL Distribution forecasts for the access arrangement period contain no non-confirming capital expenditure relating to Rule 81.

As a result, ActewAGL Distribution does not expect to recover any such capital expenditure through a surcharge under Rule 82. ActewAGL Distribution has no current surcharges approved under the Gas Code.[73]

As previously stated in section 7.1.3.2, ActewAGL Distribution does not have a speculative capital expenditure fund (or a corresponding speculative investment account under the former Gas Code), nor does it intend to establish one during the access arrangement period.

7.2.2.2 Capital contributions

Rule 82 allows a user to make a capital contribution towards a service provider's capital expenditure. Rule 82(3) stipulates that a capital contribution may with the approval of the AER be rolled into the service provider’s capital base provided that there is a mechanism in place to ensure that no part of the capital expenditure contributed by users benefits the service provider through increased revenue.

[73] Transitional Provision 3(6) at Schedule 1 of the NGR allows a surcharge approved by the relevant regulator under section 8.25 of the former Gas Code to be taken as a surcharge approved by the AER under Rule 83.

The amount of forecast capital contributions by asset class for each year of the access arrangement period is provided in Chapter 6 (capital expenditure) in Table 6.19.

No forecast capital contributions are included in the regulatory capital base. ActewAGL Distribution is not proposing a mechanism to include capital contributions in the capital base. However, consistent with the PTRM developed by the AER, ActewAGL Distribution includes capital contributions in the tax asset base as well as recognising them as taxable income in the PTRM.

7.2.3 Depreciation over the access arrangement period

Rule 77(1)(c)(ii) requires that access arrangement information includes:

> The projected capital base over the access arrangement period including a forecast of depreciation for the period including a demonstration of how the forecast is derived on the basis of the proposed depreciation method

Rule 88 deals with the required depreciation schedule on which the assets constituting the capital base are to be depreciated for inclusion in the projected capital base to be constituted as per Rule 78(c) (quoted above). According to Rule 88(2), the schedule may consist of separate schedules for particular classes of asset.

ActewAGL Distribution proposes to continue to apply straight-line depreciation in the access arrangement. A straight-line depreciation method is consistent with depreciation criteria set out in Rule 89.

Regulatory asset categories are depreciated over the expected economic life of each asset group. Straight line depreciation ensures that an asset is only depreciated once and promotes the efficient growth in the market for gas distribution services in the ACT and surrounding regions. Furthermore, straight-line depreciation provides sufficient cash flows for ActewAGL Distribution to meet all its expected financing costs during the access arrangement period. ActewAGL Distribution's network is growing and does not propose to defer any of its depreciation according to Rule 89(2).

7.2.3.1 Asset lives

ActewAGL Distribution has separated its regulatory assets into nine asset categories, which are consistent with the classes used in the earlier access arrangement period. Each asset category has been assigned a *standard life* and a *remaining asset life* which reflect the expected economic life of those assets. The standard life is consistent with what has been applied in the earlier access arrangement period. ActewAGL Distribution notes that the access arrangement information in November 2004 Table 3.5 has different assigned standard life for high pressure services and medium pressure mains. However, the roll forward of the capital base has applied the standard life as set out in Table 7.4 of this access arrangement information. This is also consistent with ActewAGL Distribution actual accounting.

The standard life of each asset category reflects the expected technical life of a new asset. The asset categories and standard lives are set out below in Table 7.4.

Table 7.4 ActewAGL Distribution asset categories and standard asset lives 2010/11 to 2014/15

Asset Type	Standard life (Years)
Primary (HP) Mains	80.0
HP Services	50.0
MP Mains	50.0
MP Services	50.0
Regulators, Valves (TRS, SRS)	15.0
Contract meters	15.0
Tariff meters	15.0
IT System	5.0
Regulatory Costs	5.0

Existing assets have been depreciated over their estimated average remaining life. Since each asset category contains assets that are commissioned at different points in time remaining asset lives entails a degree of averaging.

To determine the remaining lives of the assets at 1 July 2010, ActewAGL Distribution has adopted an approach that maintains the level of real depreciation. This approach ensures that the depreciation allowance is not affected when existing assets with new capital expenditure are combined.

The remaining life is calculated separately for each asset category as follows:

- the opening asset value at 1 July 2010 is determined for each category;
- the real 2010/11 depreciation is calculated in the roll forward model, for each asset category, on the assumption that there is no inflation or capital expenditure in 2010/11; and
- the remaining asset life of an asset category is obtained by dividing the opening asset value (step 1) by the level of real depreciation (step 2).

Table 7.5 sets out the remaining asset lives of each asset categories.

Table 7.5 ActewAGL Distribution remaining asset lives 1 July 2010

Asset Category	Years
Primary (HP) Mains	64.85
HP Services	32.53
MP Mains	29.83
MP Services	39.71
Regulators, Valves (TRS, SRS)	10.86
Contract meters	12.98
Tariff meters	11.03
IT System	3.66
Regulatory Costs	3.87

Similar to section 7.1.1 above, ActewAGL Distribution has calculated remaining lives for 2011 to 20015. These are indicative only and provided in accordance with the RIN. ActewAGL Distribution does not consider the information is needed for the price determination for access arrangement period. The method used to derive them is not the method proposed to calculate remaining lives for the access arrangement period beginning 2015.

7.2.3.2 Forecast depreciation

Forecast depreciation has been calculated using the AER's post-tax revenue model and the values for the access arrangement period are set out in Table 7.6.

Table 7.6 Economic depreciation 2010/11 to 2014/15

$000 nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Straight line depreciation	9.5	11.0	12.8	14.7	15.2
Inflation adjustment	-5.8	-6.3	-7.9	-10.0	-10.1
Economic depreciation	3.6	4.7	4.9	4.8	5.1

7.2.3.3 Provisions for calculating depreciation for the 2015 opening capital base

Rule 90 specifies that a full access arrangement must contain provisions governing the calculation of depreciation for establishing the opening capital base for the next access arrangement period after the one to which the access arrangement currently relates.

ActewAGL Distribution proposes to adopt a depreciation schedule that has been calculated using *forecast* capital expenditure for rolling forward the capital base from 1 July 2010 to 30 June 2015. This is consistent with the NGR which require that a full access arrangement must include provisions governing the calculation of depreciation for establishing the opening capital base for the next access arrangement; and that these must resolve whether depreciation is to be based on actual or forecast capital expenditure.

Whilst the NGR are clear that depreciation can be based on actual or forecast capital expenditure, the AER has expressed the view in its AA Guideline[74] that the preferred approach is for depreciation to be based on forecast capital expenditure. Consistent with this guideline, ActewAGL Distribution proposes that depreciation schedule for establishing the opening capital base at 1 July 2015 will be based on forecast capital expenditure.

7.2.4 Forecast disposals in the access arrangement period

No asset disposals with cash effects are forecast for the access arrangement period. For further details, see section 6.2.3.2 of this access arrangement information.

7.2.5 Indexation adjustment of the projected capital base for the access arrangement period

To adjust the forecast capital base and capital expenditure in the PTRM into nominal dollars, ActewAGL Distribution has utilised the rate of inflation established in section 8.2 of this access arrangement information.

7.2.6 Forecast regulatory asset base

The capital base by asset class can be indirectly calculated by using the information in provided in the PTRM in attachment R to this access arrangement information.

ActewAGL Distribution has projected the capital base into the access arrangement period consistent with Rule 78 using the elements discussed above as demonstrated in Table 7.7.

Table 7.7 Projected capital base 2010/11 – 2014/15

$ million ($2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15
Opening capital base	278.3	294.8	360.9	448.1	445.4
plus Forecast capital expenditure	25.8	76.7	99.2	10.8	11.4
less Forecast depreciation	9.3	10.6	12.0	13.6	13.7
less Projected redundant assets	-	-	-	-	-
less Forecast disposals	-	-	-	-	-
Closing capital base	294.8	360.9	448.1	445.4	443.1

7.2.7 Capital redundancy mechanism

Rule 85 provides that the service provider may include, and the AER may require it to include, a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services are removed from the capital base. Any reduction in the capital base via such a mechanism can only take place at the commencement of the access arrangement period immediately following the introduction of the mechanism.

In such cases, the access arrangement can include a mechanism for sharing costs associated with the decline in demand for pipeline services between the service provider and users. Before requiring a capital redundancy mechanism, the AER must take account

[74] AER, Access Arrangement Guideline, March 2009, p 61

of the uncertainty such a mechanism would cause and the effect of such uncertainty on the service provider, users and prospective users.

7.2.7.1 Outline of the proposed mechanism

ActewAGL Distribution's proposed capital redundancy mechanism is included in part 4 of the access arrangement proposal.

ActewAGL Distribution does not anticipate that any of its assets would become redundant during the access arrangement period. Nevertheless, such a mechanism is warranted to provide a framework should capital redundancy eventuate, including providing for adequate consideration by the AER of the consequences for the business.

The access arrangement in the earlier period incorporates a capital redundancy mechanism as follows:

> 4.6 With effect from the Revisions Commencement Date, the Relevant Regulator may reduce the Capital Base by an amount representing:
>
> (a) any assets that in the reasonable opinion of the Relevant Regulator have ceased to contribute to the delivery of Services;
>
> (b) any assets that have been transferred by ActewAGL or in relation to which ActewAGL has entered into a binding agreement for its transfer: or
>
> (c) any assets that in the reasonable opinion of the Relevant Regulator have decreased in value because of a decrease in its utilisation resulting from a decline in the volume of sales of the Service.
>
> 4.7 In assessing the reduction in the Capital Base due to a decreased utilisation of assets resulting from a decline in the volume of sales of a Service, the Relevant Regulator may take into account the reduction in Total Revenue and any possible increase in Tariffs paid by Users resulting from the decline in utilisation of assets.

ActewAGL Distribution is proposing to revise this capital redundancy mechanism to clarify when the mechanism should apply and the issues to be considered by the AER. In this regard, ActewAGL Distribution proposes to adopt the capital redundancy mechanism in the Jemena Gas Networks access arrangement for the earlier access arrangement period. The proposed revision refines the current mechanism in a number of ways. For example, "transferred" is to be changed to "sold or disposed". The range of factors to be considered is expanded to include, for example, the value of the assets when the assets were first included in the asset base and their current value.

7.2.7.2 Potential uncertainty caused by a capital redundancy mechanism

A capital redundancy mechanism has the potential to cause uncertainty should it be applied arbitrarily or without proper and complete consideration of its effect on the service provider or users. ActewAGL Distribution considers that Rule 85 places a strong obligation on the AER to take account, at the invocation of capital redundancy measures, of the uncertainty such a mechanism would cause and the effect of such uncertainty on the service provider, users and prospective users. While there will always be some uncertainty associated with the application of a capital redundancy mechanism, the proposed revisions aim to reduce this uncertainty by clarifying where and how the mechanism should be applied.

8 Rate of return and forecast inflation

This chapter of the access arrangement information explains the parameters of the capital asset pricing model proposed for calculation of the weighted average cost of capital for the rate of return during the access arrangement period and derivation of the forecast rate of inflation required by the post tax revenue model.

8.1 Return on capital

This section of the access arrangement information addresses the requirement of Rule 72(1)(g) for access arrangement information to include “the proposed rate of return, the assumptions on which the rate of return is calculated and a demonstration of how it is calculated”.

The revenue and pricing principles of the NGL (section 24) state that a reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which the tariff relates. Furthermore, the principles state that businesses should have regard to the economic costs and risks of the potential for under and over investment by a service provider and the economic costs and risks of the potential for under and over utilisation of the facility.

According to rule 87(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. Rule 87(2) sets an assumption for calculation of the rate of return that the service provider conforms to benchmarks in respect of efficiency, financing structure and other financial parameters and that the service provider must use a “well accepted approach incorporating the costs of equity and debt, such as the Weighted Average Cost of Capital (WACC) and a well accepted financial model such as the Capital Asset Pricing Model (CAPM)”.

8.1.1 Proposed approach and parameter values

ActewAGL Distribution proposes to use the same approach for calculating a return on capital—the *Sharpe-Linter* CAPM—as it did in the earlier access arrangement period. However, in line with the AER’s preference, ActewAGL Distribution will use a post-tax nominal framework for the access arrangement period in contrast to the pre-tax real framework in the earlier access arrangement period.

There is a range of asset pricing models, each incorporating different assumptions about the behaviour of investors and measuring risk in a variety of ways. Though the NGR do not prescribe a particular model to determine the return on capital, the AER has in its decisions to date[75] chosen to use a single model, a vanilla post-tax WACC combined with the Sharpe-Lintner CAPM, to determine rates of return on equity.

[75] On page 335 in the final decision in May 2009 in the AER’s review of the WACC parameter for electricity and distribution network, the AER states that they are “not aware of any instances where an Australian regulator has adopted an alternative model”.

Although the Sharpe-Lintner CAPM is widely used, mainly due to its simplicity, as a teaching device in business schools, it has been acknowledged for many years that the model has limitations.[76] Competing models, such as the Fama-French Three-Factor Model, are now being more widely accepted in the academic community. Some of these models have also gained wider acceptance in the financial community.

ActewAGL Distribution interprets the requirement of Rule 87 (2) to use a "well accepted" approach and model, to imply use of a conventional model and has used the most established approach for this purpose. However, ActewAGL Distribution notes that with its wider acceptance in academia and the financial community, the Fama-French model could also have been an appropriate method for this purpose.

In accordance with this approach, ActewAGL's nominal post-tax WACC is calculated using the formula outlined in Box 8.1

The NGR do not prescribe values to the parameters used in the WACC, stating only that "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".

Consistent with these criteria, ActewAGL Distribution proposes the values for the cost of capital parameters listed in Table 8.1. These values, and their derivation are explained in the following sections.

Box 8.1 Formula for ActewAGL Distribution's proposed nominal post tax WACC

$$\mathrm{WACC} = R_e \cdot \frac{E}{V} + R_d \cdot \frac{D}{V}$$

such that: $R_e = R_f + \beta_e \cdot \mathrm{MRP}$ and $R_d = R_f + \mathrm{DRP}$

Where :

R_e is the nominal return on equity

R_f is the nominal risk free rate of return

β_e is the equity beta

MRP is the market risk premium

R_d is the nominal return of debt

DRP is the debt risk premium

$\frac{E}{V}$ is the equity share of total value

$\frac{D}{V}$ is the debt share of total value $(= 1 - \frac{E}{V})$

[76] This was also discussed in the AER's final WACC decision in May eg. pp 334-335.

Table 8.1 Parameters of ActewAGL Distribution's proposed cost of capital

CAPM parameter	Value
Nominal risk free rate	5.12%
Equity beta	1.0
Market risk premium	7.5%
Debt risk premium	4.96%
Debt share of total value (gearing)	60%
Gamma (utilisation of imputation credits)	65%
Nominal return on equity	12.62%
Nominal return on debt	10.08%
Nominal vanilla WACC	11.09%

8.1.2 The AER review of the WACC for electricity networks

On 1 May 2009, the AER published a decision on the WACC parameters to be adopted in determinations for electricity transmission and distribution network service providers (the electricity network WACC decision). Subsequent such reviews are to be conducted every five years, for transmission, and at least every five years for distribution.[77] In the electricity network WACC decision, the AER states that:[78]

> … the outcome of the AER's WACC review applies only to electricity determinations, and has no direct or formal applicability to gas access arrangements. The determination of the WACC for access arrangements is subject to requirements under the National Gas Law (NGL) and National Gas Rules (NGR), which are not being considered in this review.
>
> Nonetheless, given the similarity of issues, the AER may use the outcome of this review for the consideration of WACC issues in future gas access arrangement reviews.

Given that the AER has said that it may use the electricity network WACC decision in consideration of WACC issues in future gas access arrangement reviews, ActewAGL Distribution has closely noted the methods and arguments outlined in this decision. Where relevant, the issues raised are included in the parameter discussions below.

ActewAGL Distribution notes that gas distribution businesses were included in the AER's and its consultants' samples for some elements of the electricity network WACC decision. However it was correctly observed by the AER elsewhere in the decision that combined gas and electricity distribution businesses differ in their underlying business risks compared to individual electricity networks. The AER, for example, noted that.

> Specifically, gas businesses may have a higher business risk than electricity businesses due greater volatility of cash flows from relatively higher volume fluctuations.[79]

[77] National Electricity Rules, clause 6.5.4
[78] AER, Final decision of electricity networks WACC review, p 6
[79] AER, Final decision of electricity networks WACC review, p 108

This additional risk should be compensated by the equity beta or the debt risk premium, further discussed at sections 8.1.4.4 and 8.1.5.1 below.

8.1.3 Treatment of dividend imputation credits

Under the Australian taxation system, tax credits (imputation credit) created by an Australian company may be redeemed by domestic shareholders. An imputation credit is created for each dollar of eligible tax paid by companies. Imputation credits are distributed to shareholders through the payment of franked dividends. Imputation credits therefore represent a benefit to domestic shareholders for their investment in the company in addition to dividends (and capital gains).

The equation for deriving the utilisation imputation credits, represented by the Greek character γ (*gamma*), is provided in Box 8.2.

Box 8.2 Definition of the imputation credit

$$\gamma = U \cdot \frac{IC}{Tax}$$

Where:

U = weighted average of investors utilisation rate of imputation credits

IC = the imputation credits assigned to the business during a period

Tax = the amount of tax paid by the business during the period

Gamma can take values between zero and one. In the electricity network WACC decision, the AER departed from previous practice of setting gamma to 0.50 and determined that a reasonable estimate of the assumed utilisation of imputation credits is 0.65. The 0.65 was determined by the AER using the following arguments:

- the payout ratio should be assumed to be 100 per cent;
- the use of a domestic CAPM requires an assumption that participants should be assumed to be local to the extent that they invest in the domestic equities market; and
- tax data on imputation credits and market event studies are reasonable estimates for the market value of imputation credits.

ActewAGL Distribution disagrees with the basis of this decision on gamma.[80] However, given the recent nature of this decision by the AER and the lack of new information available, ActewAGL Distribution has simply applied a value for gamma of 0.65 for the access arrangement in order to limit the need for debate on this aspect and concentrate focus on the other key components of the WACC.

8.1.4 Proposed WACC parameters for the return on equity

This section of the access arrangement information describes the parameters selected by ActewAGL to set the proposed cost of equity. The cost of equity is measured by the risk

[80] ActewAGL Distribution is in accord with the views put by the Joint Industries Group submission on this matter that the value of gamma is less than 0.5.

free rate, market risk premium and equity beta. In accordance with rule 87(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. Accordingly, an important consideration is the point in time and method of measuring the market risk premium and risk free rate. These issues are discussed below.

8.1.4.1 Sample period

This information is confidential and is provided as a separate document (see attachment L to this access arrangement information).

8.1.4.2 Nominal risk free rate

The risk free rate parameter represents the return investors would earn on assets with no volatility and no default risk. The electricity network WACC decision proposes to set the risk free rate equal to the yield on a 10-year Commonwealth Government Securities (CGS). Government bonds have traditionally been viewed as a risk-free return.

The current global financial crisis has introduced a further consideration on the risk free rate of return. In October 2008, the Australian Government issued a guarantee on bank bonds due to expire on 11 October 2011. Although this Australian Government guaranteed bonds provide a significantly higher yield than the CGS, ActewAGL Distribution proposes to use the *annualised* yield on CGS with a maturity of 10 years as a proxy for the risk free rate of return. This approach is consistent with the electricity network WACC decision.

Specifically, ActewAGL Distribution proposes the use of Treasury Bonds TB122 and TB126 and applying the sample period as defined in section 8.1.4.1. These mature on 15 February 2019 and 15 April 2020 respectively. By using the average of two Commonwealth Government Bonds, the risk of sudden market developments affecting one bond is diversified.

For the purposes of this submission, ActewAGL Distribution has used the 20 business days from 4 May to 29 May 2009 for the above mentioned Treasury Bonds (TB122 and TB126) to determine the nominal risk free rate at 5.12 per cent.

8.1.4.3 Market Risk Premium

The difference between the return from the market and the risk free rate is termed the market risk premium. The market risk premium represents the premium investors require and can expect to invest in a well-diversified portfolio of risky assets (with only non-diversifiable risk).

In the electricity network WACC decision, the AER increased the market risk premium (MRP) from 6.0 per cent in the draft decision to 6.5 per cent[81] due to the effects of the global financial crisis and unstable market conditions. ActewAGL Distribution notes that the AER acknowledged that the MRP is currently higher than 6.5 per cent but that the AER expects this parameter to decline in value during the five year period of the decision. ActewAGL Distribution believes that there is a strong case to depart from 6.5 per cent since

[81] Section 7.6 in the final decision as of May 2009

the access arrangement period covers only a five-year portion (2010 to 2015) of the period of the electricity network WACC decision, as further explained below.

The AER considered that, prior to the onset of the global financial crisis, 6 per cent was a best estimate of a forward looking long term MRP. However equity markets have since become unstable due to the effects of the crisis. The AER considers that the prevailing medium term MRP is above the long term MRP or that there has been a structural break in the MRP. Accordingly, in the electricity network WACC decision, the AER determined that a MRP of 6.5 per cent was reasonable having regard to the desirability of regulatory certainty and stability. This is 50 basis points higher than the previous norm of 6.0 per cent.

Due to the global financial crisis, ActewAGL Distribution believes there are good reasons to believe that current market circumstances differ from the historical average. Historical estimates do not provide a reasonable basis for determining the forward looking MRP. In light of current volatile and turbulent markets, ActewAGL Distribution commissioned the Competition Economists Group (CEG) to investigate the gas network MRP. CEG's complete report is provided at attachment M to this access arrangement information. Its main findings are summarised below.

CEG used a dividend growth market (DGM) model (also known as a discounted cash flow model). The advantage of DGM is that it is forward looking. They utilised dividend forecasts published by Bloomberg for the ASX 200 companies on 5 June 2009, combined with prevailing equity prices, to calculate the implied rate of return and risk premium (MRP) over the risk free rate.

An implied value of the imputation credits consistent with the 0.65 value of gamma (as determined in the AER's electricity network WACC decision) has been included in the value of the forecast dividend. As Bloomberg provides forecast dividends only to 2013, CEG has applied two alternative methods—historical GDP growth and the long term real interest rates—to estimate the dividend growth beyond 2013. These assume 3.9 and 3.2 per cent growth respectively. Using the short and long term dividend forecasts and the average market capitalisation of the 181 firms included in the sample, CEG estimates the market risk premium by subtracting from this rate of return the risk free rate of 4.90 per cent. Using GDP growth (and assuming the current level is permanent) results in a market risk premium in the range of 8.3 to 8.9 per cent (8.3 per cent assuming long run GDP growth matches the real CGS growth assumption).

CEG demonstrates that, if the market risk premium is expected in 10 years time to fall back to the AER's initial estimate of 6 per cent, the range for the "prevailing forward looking short run average MRP" increases to between 11.3 and 13.0 per cent over the intervening period. Their calculation shows that the assumption of a future MRP lower than the current market does not result in a lower MRP now, but rather a higher one.

The logic of CEG's report is that, if investors are pricing in higher volatility than the historical average, then it is reasonable to expect that the MRP, too, will be higher. As described the report shows that the MRP is above 8.3 per cent as at the middle of May 2009. It is also important to note that if the long term MRP is assumed to come down to 6 per cent within 10 years, the MRP for these ten years is actually closer to 13.0 per cent. ActewAGL Distribution believes that this demonstrates that the AER's final WACC decision in May 2009 regarding the MRP of 6.5 per cent was too low and takes into account neither the future nor market circumstances. However, ActewAGL Distribution acknowledges that there is substantial uncertainty about both the level and future path of the MRP.

The AER has also argued that the WACC parameters should be estimated independently from each other.[82] That is, if the market risk free rate decreases, it can not be an argument that the MRP should be adjusted or vice versa. This position must be considered along with:

- the unusually turbulent market;
- CEG's report that demonstrates that the MRP is above 8.3 per cent;
- the MRP must be closer to 13.0 per cent if it is expected to fall back to the assumed 6 per cent in 10 years time; and
- the sensitivity of the analysts' dividend forecasts and the risk that their forecasts are too optimistic.

ActewAGL Distribution proposes a MRP of 7.5 per cent for the access arrangement period starting in July 2010. Considering the market circumstances when the estimate of 7.5 per cent was made and the AER's long term view of the MRP, this is a very conservative and low estimate of the MRP and is below even the low end of the range provided by CEG. In fact, actual dividends would need to be 20 per cent lower than the Bloomberg forecasts to justify a long run market risk premium of less than 7.5 per cent.

ActewAGL Distribution's proposed MRP of 7.5 per cent is also consistent with the long run (1883-2007) historical average MRP estimates provided by Officer and Bishop for the period ending 2007 (ie, ending prior to the full impact of the global financial crisis).[83] That is, ActewAGL Distribution's estimate of the MRP is both conservative in the sense that it is less than the best estimate of the prevailing forward looking MRP and is no higher than the long run historical average MRP estimated by Officer and Bishop.

8.1.4.4 Equity beta

The beta coefficient is a key parameter in the CAPM. The equity beta measures the correlation between the returns of an individual security and a well-diversified portfolio. It is therefore a measure of the premium equity investors require to hold an asset or business of given riskiness. In practice, the equity beta is a scaling factor on the MRP. In the earlier access arrangement period, the ICRC determined an equity beta for the ActewAGL Distribution gas network of 1.0. At that time, ActewAGL Distribution sought an equity beta between 0.98 and 1.09.

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[82] For example, on page 44 in the final decision of the WACC parameters in May 2009, the AER writes that it "considers that the integrity in the estimation of each individual WACC parameter is important" in response to CEG's statement that the MRP had moved in the opposite direction to the yield on CGS.

[83] See Table 6 of http://www.aer.gov.au/content/item.phtml?itemId=722310&-nodeId=8f0c8c14b575abf3d8b5f65b9f86936e&fn=JIA%20Appendix%20G%20-%20Officer%20and%20Bishop%20-%20Market%20risk%20premium.pdf

The electricity network WACC decision included several references to the conceptual argument that gas businesses might bear a higher risk than electricity businesses. The decision states, for instance, that:[84]

> The AER observes that electricity businesses in the United States provide generally lower equity beta estimates than gas businesses.

The AER has previously stated that it places less weight on foreign findings than those for Australia.[85] However, international circumstances need to be considered for a robust analysis of the differences between gas and electricity business betas since there is insufficient data available on the ASX.

ActewAGL Distribution commissioned CEG to examine the equity beta for its gas network as well as providing information of the difference between gas and electricity businesses betas. CEG estimated the equity risk premium (MRP times βe) for six Australian utilities used by the AER in reaching its electricity network WACC decision. Consistent with the methodology applied to estimate the MRP, CEG finds that, if dividends grow in line with analysts' expectations out to 2012/13, and thereafter in line with inflation (assumed to be 2.5 per cent per annum), the implied average equity risk premium for the businesses is 14.6 per cent measured relative to the 10 year CGS yield. This indicates that in the current circumstances the market regards these companies as more risky than the market as a whole.

Gas versus electricity businesses

This information is confidential and is provided as a separate document (see attachment L to this access arrangement information).

Conclusion

Considering the evidence presented above, ActewAGL Distribution considers that there is persuasive evidence that a gas distribution business bears a higher operational risk than an electricity distribution business. While precise estimates are difficult to make, the analysis by CEG indicates that the equity beta for a gas distribution business is observed to be greater than 1.0. However, considering the balance, on one hand, between consistency with earlier gas determinations, managing investor risk and the CEG finding of an equity beta greater than 1.0 and, on the other hand, noting (but not supporting) the AER's findings in the electricity network WACC decision (0.8), ActewAGL Distribution proposes that the equity beta must be no less than 1.00 and has proposed 1.00, the same as for the earlier access arrangement period.

8.1.5 Proposed WACC parameters for the cost of debt

The cost of debt is calculated as follows:

$$R_d = R_f + DRP$$

[84] AER 2009 Final decision on the review of the weighted average cost of capital (WACC) parameters, May
[85] AER, Final decision on the review of the weighted average cost of capital (WACC) parameters, May, p 330

ActewAGL Distribution's proposed WACC assumes a debt to total assets gearing of 60 per cent. This level of gearing is consistent with previous regulatory precedent and in line with the benchmark financial structures that reflects best practice. This level of gearing also reflects that determined in the electricity network WACC decision.

8.1.5.1 Debt risk premium

The debt risk premium is what a business must pay on top of the nominal risk free rate to secure debt financing. The debt risk premium a business pays depends on the perceived riskiness of the business. Low risk companies will be able to secure debt financing at a cheaper rate than more risky companies. The gearing of a company is one parameter when measuring the risk of the company. As mentioned above, ActewAGL Distribution proposes gearing of 60 per cent be assumed for the access arrangement period.

In establishing the cost of debt for the purposes of calculating the return on capital, a debt risk premium is to be added to the nominal risk free rate. Consistent with the assumed gearing, accepted regulatory practice and the electricity network WACC decision, ActewAGL Distribution assumes a credit rating of BBB+ to calculate the debt risk premium.

There are currently insufficient corporate bonds with a BBB+ rating with ten years to maturity for Bloomberg to publish a 10-year bond rate. When previously faced with this difficulty, in the 2008 SP AusNet final determination, the AER estimated the 10-year BBB+ Bloomberg Fair Value yield as the eight-year Bloomberg BBB predicted yield plus the spread between eight and 10-year A rated Bloomberg predicted yields.

ActewAGL Distribution notes the AER's preference for the use of Bloomberg as a data source for the calculation of the debt premium. CBA Spectrum is an alternative data provider also used by analysts and investors. For reasons outlined in its revised electricity proposal in January 2009, ActewAGL Distribution proposed to use the CBA Spectrum as a data source. In the final price determination in April 2009 the AER considered Bloomberg to provide more accurate data than CBA Spectrum.[86]

However, the report by CEG at attachment T to this access arrangement information *Estimating the cost of 10 year BBB+ debt* shows that using Bloomberg would imply reliance on a single or very small number of observations for estimation of the debt margin, and would not give rise to estimates consistent with the impact of the market conditions in September /October 2008. While preferring CBA Spectrum, ActewAGL Distribution notes the AER's view in the final electricity network decision whilst not agreeing with this outcome and to avoid any potential bias or errors from use of a single data source, ActewAGL Distribution believes the most reasonable method of estimating the debt premium is to use the average of relevant CBA Spectrum (BBB+, 10-year) published data and Bloomberg derived yields (calculated as described above). Applying this method for this proposal and the same sample period as for the risk free rate, ActewAGL Distribution has estimated a debt margin of 4.96 per cent.

[86] AER 2009, Final decision of Australian Capital Territory distribution determination 2009-10 to 2013-14, p 105

8.2 Forecast inflation

The expected rate of inflation is not an explicit parameter in the calculation of the WACC. It is however required for use in the PTRM. The PTRM framework provides a real rate of return to the business which means that the expected inflation rate included in the nominal WACC must be appropriately measured.

Forecast future movement in the CPI has traditionally been calculated using the Fischer equation as the difference between the nominal and the real risk free rates. The Fischer equation is based on accepted theory and is therefore a non-arbitrary method for calculating CPI.

In recent years there has, however, been strong market evidence that the difference in yields between nominal and indexed CGS results in an overestimate of expected inflation. In SP AusNet's final decision in January 2008, the AER said:

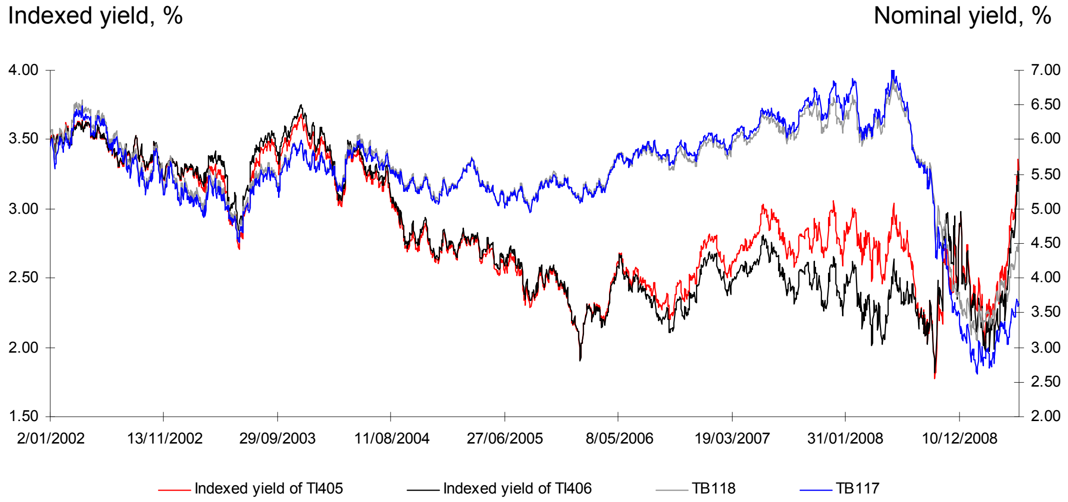
> The AER maintains its view in its draft decision that a market based estimate of inflation is generally preferable to any other method. However, acknowledging the present limitations of both the Fisher equation and inflation swaps, the AER is not aware of a reliable market based alternative that can be mechanistically applied in a similar way to these measures. It is in this context that the AER has had to resort to a general approach to forecasting inflation.[87]

In the case of SP AusNet, the AER applied the Reserve Bank of Australia's (RBA's) short-term inflation forecasts and adopted the mid-point of the RBA's target inflation band (that is, 2.5 per cent) beyond that period for the remaining years of the ten-year period. An implied 10-year forecast is derived by averaging these individual forecasts. This approach was also applied to ActewAGL Distribution's electricity final decision and those of the NSW electricity distribution businesses in April 2009.

ActewAGL Distribution notes that the AER, in connection with the SP AusNet final decision in January 2008, also stated that "a market based estimate of inflation is generally preferable". Figure 8.1 demonstrates how the indexed and nominal CGS yields have tracked since 2002. As can be seen, the yield on indexed CGS fell more than that for the nominal CGS from 2004. However, as can also be noted, nominal CGS yields fell sharply at the end of 2008 and the yield on nominal and indexed CGS seems to have normalised again as was the case prior to 2004.

[87] AER 2008, Final Decision SP AusNet Transmission Determination 2008-09 – 2013-14, p 102

Figure 8.1 Yield on nominal and indexed CGS from 2002 to May 2009



To rule out possible bias of the indexed CGS related to the nominal CGS TB117 and TB118, ActewAGL Distribution also calculated average nominal CGS for TB117, TB118, TB119, TB120, TB122 and TB124 and compared them with the same indexed CGS as in Figure 8.1. The results are shown in Figure 8.2.

Figure 8.2 Average yield on nominal and indexed CGS from 2002 to May 2009

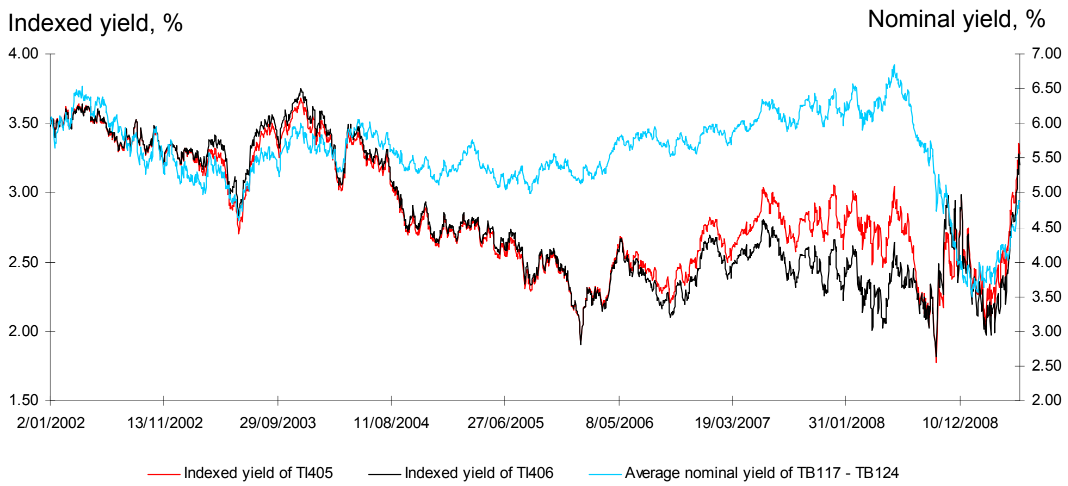


Figure 8.1 and Figure 8.2 show the same trend, demonstrating that the bias is not related only to specific bonds.

Considering the AER's preference of using a market based estimate to calculate inflation, ActewAGL Distribution proposes the following approach:

- If there is no bias between the nominal and indexed CGS the average inflation should be based on the Fischer equation; or

- If there is a bias, the average inflation should be based on the RBA's forecast in accordance with the same methodology applied on ActewAGL Distribution's electricity network decision in April 2009.

ActewAGL Distribution believes an independent, objective and unbiased inflation rate can be calculated by this method.

ActewAGL Distribution's proposed inflation forecast for the access arrangement period starting 2010 and used in the PTRM is based on the Fischer equation as ActewAGL Distribution believes that, at the time of this proposal, there currently is no bias between the indexed and nominal CGS. For the purpose of this submission, ActewAGL Distribution has used as a sample period the 20 day average of 4 May 2009 to 29 May 2009 (inclusive). The inflation has been calculated using Treasury Bonds TB122 and TB126 for the nominal risk free rate and TI405 and TI406 for the real risk free rate using the same methodology as for the calculation of the nominal risk free rate. Table 8.2 provides the expected rate of inflation during the access arrangement period.

Table 8.2 Expected rate of inflation during the access arrangement period

Per cent	2011-16
Nominal risk free rate	5.12%
Real risk free rate	2.97%
Average expected inflation (Fischer equation)	2.09%

The inflation used in this access arrangement information to calculate all Tables in 2009/10 dollars is based on actual CPI (All groups, 8 capital cities average June over June, by ABS) and the RBA's forecast for the individual years (2008/09 and 2009/10).

9 Operating expenditure

This chapter of the access arrangement information explains the derivation of operating and maintenance costs and the basis of other non-capital costs including taxation, self insurance and greenhouse gas emissions trading costs.

As defined under Rule 69, *operating expenditure* for the purposes of price and revenue regulation under the Rules means:

> … operating, maintenance and other costs and expenditure of a non-capital nature incurred in providing pipeline services and includes expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services. [88]

The revenue and pricing principles in the NGL (section 24) state that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing reference services and complying with a regulatory obligation or requirement or making a regulatory payment.

9.1 Operating expenditure 2004-10

This section of the access arrangement information addresses the requirement of rule 72(1)(a)(ii) for the access arrangement information to include "operating expenditure (by category) over the earlier access arrangement period".

ActewAGL Distribution's actual gas network operating costs for 2004/05 to 2007/08, forecasts for 2008/09 and 2009/10 are shown in Table 9.1.

9.1.1 Controllable costs

Operations and maintenance costs in Table 9.1 are those incurred by ActewAGL Distribution. A substantial proportion of those costs are the fees and charges paid to JAM under its contract with ActewAGL Distribution to provide field and asset management services related to the operation of ActewAGL Distribution's gas distribution network. As such, it includes the costs of labour, materials and an allocation of Jemena corporate overheads. The non-system asset charge is paid to JAM and is a charge to compensate it for the capital costs return on non system assets required in the management of the network. These costs are not covered by the fixed fees (management service fee and asset services fee) which relate only to JAM's operating costs in providing its services to ActewAGL Distribution. ActewAGL Distribution also pays a fee to JAM for network development.

[88] This definition differs in important respects from that in clause 8.36 of the former Gas Code which defines non-capital costs as:

> … the operating, maintenance and other costs incurred in the delivery of the Reference Service. Non Capital Costs may include, but are not limited to, costs incurred for generic market development activities aimed at increasing long-term demand for the delivery of the Reference Service.

ActewAGL Distribution also incurs costs associated with corporate overheads, its own marketing and other direct costs (for example, insurance) as set out in Table 9.1.

9.1.2 Other allowable costs

Other allowable costs include government levies, UNFT and costs associated with implementation of full retail contestability in the ACT gas market and costs of unaccounted for gas. Contestability costs were allowed as a pass-through in the 2001 Access Arrangement and again in 2004.

Table 9.1 ActewAGL Distribution's gas network operating costs 2004–10

$ million (2009/10)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*	
Controllable costs							
Operating and maintenance	8.81	8.03	8.14	8.45	8.39	8.82	50.64
Corporate overheads	2.10	2.17	2.25	2.33	2.65	3.30	14.80
Non-system asset charge	0.27	0.54	0.54	0.54	0.55	0.52	2.98
Marketing	1.16	0.90	1.15	1.20	1.30	1.33	7.04
Other direct costs	(0.0)	0.10	0.02	0.35	0.44	0.23	1.13
Total controllable costs	**12.35**	**11.75**	**12.11**	**12.87**	**13.32**	**14.19**	**76.60**
Other allowable costs							
Government levies	0.41	0.45	0.54	0.55	0.50	0.65	3.09
Utilities Network Facilities Tax	0.00	0.00	2.23	3.72	3.46	3.33	12.73
Contestability costs	0.65	0.52	0.52	0.52	0.52	0.56	3.29
Unaccounted for gas	0.24	0.48	0.63	0.67	1.21	0.74	3.97
Other direct Costs	0.27	0.36	0.27	(0.0)	0.18	0.22	1.29
Total other non-capital costs	**1.57**	**1.81**	**4.18**	**5.45**	**5.86**	**5.49**	**24.37**
Total operating expenditure	**13.92**	**13.56**	**16.29**	**18.33**	**19.18**	**19.69**	**100.96**

9.1.3 Comparison between actual operating expenditure and the 2004 approved operating expenditure

Table 9.2 provides operating costs approved by the ICRC under the earlier access arrangement while Table 9.3 shows variation between actual and approved operating expenditures for the earlier access arrangement period.

Table 9.2 ICRC approved operating expenditure for ActewAGL Distribution's earlier access arrangement

$ million (2009/10)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Controllable costs							
Operating and maintenance	7.89	8.07	8.44	8.56	8.68	8.80	50.44
Corporate overheads	2.19	2.19	2.19	2.19	2.19	2.19	13.16
Non-system asset charge	0.55	0.55	0.55	0.55	0.55	0.55	3.29
Marketing	1.67	1.67	1.67	1.67	1.67	1.67	10.01
Other controllable costs	0.27	0.27	0.27	0.27	0.27	0.27	1.65
Total controllable costs	**12.58**	**12.75**	**13.13**	**13.24**	**13.37**	**13.48**	**78.55**
Other allowable costs							
Government levies	0.63	0.63	0.63	0.63	0.63	0.63	3.77
Utilities Network Facilities Tax	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Contestability costs	0.51	0.53	0.53	0.53	0.53	0.51	3.13
Unaccounted for gas	0.45	0.46	0.46	0.46	0.47	0.47	2.75
Other costs	0.27	0.27	0.27	0.27	0.29	0.29	1.67
Total other non-capital costs	**1.86**	**1.89**	**1.89**	**1.89**	**1.91**	**1.90**	**11.32**
Total operating expenditure	**14.44**	**14.64**	**15.01**	**15.13**	**15.28**	**15.38**	**89.87**

Table 9.3 shows that ActewAGL's actual *Total operating expenditure* was $11.1 million (or 12.3 per cent) in excess of that allowed by the ICRC across the access arrangement period. However, this includes the effect of a $12.7 million expenditure on *UNFT* as the result of its introduction by the ACT Government during 2006/07. Without the impact of this item, actual and forecast expenditure across the 2004-10 access arrangement period would be $1.6m (or 1.8 per cent) below the ICRC-approved allowance for the earlier access arrangement period.

Controllable costs are expected to be $2.0 million (or 2.5 per cent) below that allowed by the ICRC. The main contributor to this is a $3.0m (or 29.6 per cent) less than forecast expenditure on *Marketing*. Running counter to this outcome, *Corporate overhead* costs are expected to be $1.6 million (or 12.4 per cent) above the ICRC allowance, mainly due to the change from an owned to a leased corporate head office in 2008.

In the category of *Other allowable costs*, besides the impact of the UNFT mentioned above, expenditure on *Unaccounted-for gas* will be $1.2 million (or 44 per cent) greater than that allowed by the ICRC while expenditure in the *Other* costs category is $0.4 million (or 23 per cent) below that allowed by the ICRC due to lower expenditure level on bushfire mitigation than forecast.

Material variations are discussed in the following sections.

Table 9.3 Variation between actual and approved operating costs for the earlier access arrangement period

$ million (2009/10)	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	Total
	Actual	*Actual*	*Actual*	*Actual*	*Forecast*	*Forecast*	
Controllable costs							
Operating and maintenance	(0.92)	0.03	0.30	0.10	0.30	(0.02)	(0.20)
Corporate overheads	0.09	0.02	(0.06)	(0.13)	(0.46)	(1.10)	(1.64)
Non-system asset charge	0.27	0.00	0.01	0.01	0.00	0.03	0.31
Marketing	0.50	0.77	0.52	0.47	0.37	0.34	2.97
Other controllable costs	0.28	0.18	0.25	(0.08)	(0.16)	0.04	0.51
Total controllable costs	0.23	1.00	1.02	0.37	0.04	(0.71)	1.95
Other allowable costs							
Government levies	0.22	0.18	0.09	0.08	0.13	(0.02)	0.68
Utilities Network Facilities Tax	0.00	0.00	(2.23)	(3.72)	(3.46)	(3.33)	(12.73)
Contestability costs	(0.13)	0.00	0.00	0.00	0.00	(0.04)	(0.16)
Unaccounted for gas	0.20	(0.02)	(0.17)	(0.22)	(0.74)	(0.27)	(1.21)
Other allowable costs	0.01	(0.09)	0.01	0.28	0.11	0.06	0.38
Total other non-capital costs	0.30	0.07	(2.30)	(3.57)	(3.95)	(3.60)	(13.05)
Total operating expenditure	0.52	1.08	(1.28)	(3.20)	(3.91)	(4.31)	(11.09)

Note: Figures in parentheses denote actual, forecast operating expenditure as applicable above that approved by the ICRC in ActewAGL Distribution's 2004 access arrangement.

9.1.3.1 Marketing

During the earlier access arrangement period, faced with low uptake of traditional retailer rebates for connections, ActewAGL Distribution reassessed the effectiveness of existing network marketing strategies and moved to alternatives involving the generic marketing of natural gas throughout the network area. Up until 2007 the marketing strategy was based primarily on a retailer incentivised approach to promote the use of natural gas. Over time, this became less effective and, as a consequence, resulted in lower customer uptake and lower expenditure. The new strategy to improve customer connection was implemented during 2008.

The extension of the ActewAGL Distribution gas network to Bungendore during the earlier access arrangement period was also preceded by a network owner led marketing campaign involving subsidies on the purchase of new gas appliances and for conversion of existing gas appliances. This approach proved very effective in providing greater network awareness and represents a model for future network expansions. During the earlier access arrangement period, ActewAGL Distribution continued with a corporate communication program surrounding network and public safety. Given proposed safety compliance obligations under the work safety legislation this program will continue into the access arrangement period albeit in an enhanced manner.

9.1.3.2 Corporate overheads

Corporate overhead costs have increased by 57 per cent from 2004/05 to 2009/10. This increase has mainly occurred from 2007/08 to 2009/10 and is a result of the sale and lease back of the current corporate head office in 2008, ahead of moving to new premises. The AER considered and approved this in its electricity distribution decision in April 2009. Software expenditures have also increased at the end of the earlier access arrangement period and real wage increases in line with the market.

9.1.3.3 Unaccounted for gas

Unaccounted for gas was set at 1 per cent in 2004. The forecast is that unaccounted for gas will be overspent by $1.2 million versus the ICRC allowance. The significant overspend in 2008/09 is a result of two drivers:

- a significantly higher level of UAG than approved (an average of 1.5 per cent versus an allowance of 1.0 per cent); and
- higher than forecast cost of UAG as there is no tariff adjustment.

It needs to be understood that, as discussed in section 9.2.3.3 on UAG forecasts, non-operational gas losses are likely to form only a small part of UAG on a modern and well maintained distribution network. It is far more likely that levels of UAG encountered in practice are the result of normal and acceptable industry measurement error. As such, it is important that the UAG allowance in the access arrangement period is set at an appropriate level relative to the characteristics of the network.

Some sources of increased UAG on the ACT, Queanbeyan and Palerang network have been identified as:

- the impact of moving from one to two network receipt points in 2002 and a shifting of the supply balance between these two over the subsequent period. As a result of the implementation of a point of supply from the EGP at Hoskinstown, gas receipts at Watson CTS (from the MSP) have declined from representing 100 per cent of receipts to approximately 50 per cent;
- the installation during 2006/07 and increasing use of water bath heaters (WBH) at major facilities such as Hoskinstown CTS. These currently consume approximately 12 TJ of gas per annum—about 0.2 per cent of Hoskinstown CTS receipts—in their operation and, until recently, their gas consumption was unmetered; and
- the prudent extension of customer meter lives, but with associated reductions in accuracy and increased numbers of undetected, non-registering meters, as approved by the technical regulator (see section 6.1.3 of this access arrangement information).

Notwithstanding these impacts on UAG (some of which, such as metering of WBH gas, have been rectified), ActewAGL Distribution's UAG has remained within an efficient range of 0.2 to 1.8 per cent of gas receipts during the earlier access arrangement period.

9.1.3.4 Other costs

Arising in the period immediately following the January 2003 bushfires in the ACT and region, allowance was made in forecast operating costs for ongoing compliance costs as a result of changes in operational practices to minimise fire risk. These included annual clearing of key gas sites, subsequently not required as a result of the ongoing drought limiting vegetation growth, allowance for additional commitments relating to emergency management in the ACT and NSW, ongoing community awareness programs and ongoing occupational health and safety training.

Legal expenditure arising from ACT bushfire inquiry and annual external auditor fees are also included under this item and costs for network gas for WBHs from 2008/09.

9.2 Forecast operating expenditure

This section of the access arrangement information 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 the 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 operation.

The AER's discretion under this rule is limited such that the AER must not withhold its approval of proposed operating expenditure if it is satisfied that the proposal complies with the requirements of the law and is consistent with the criteria above.

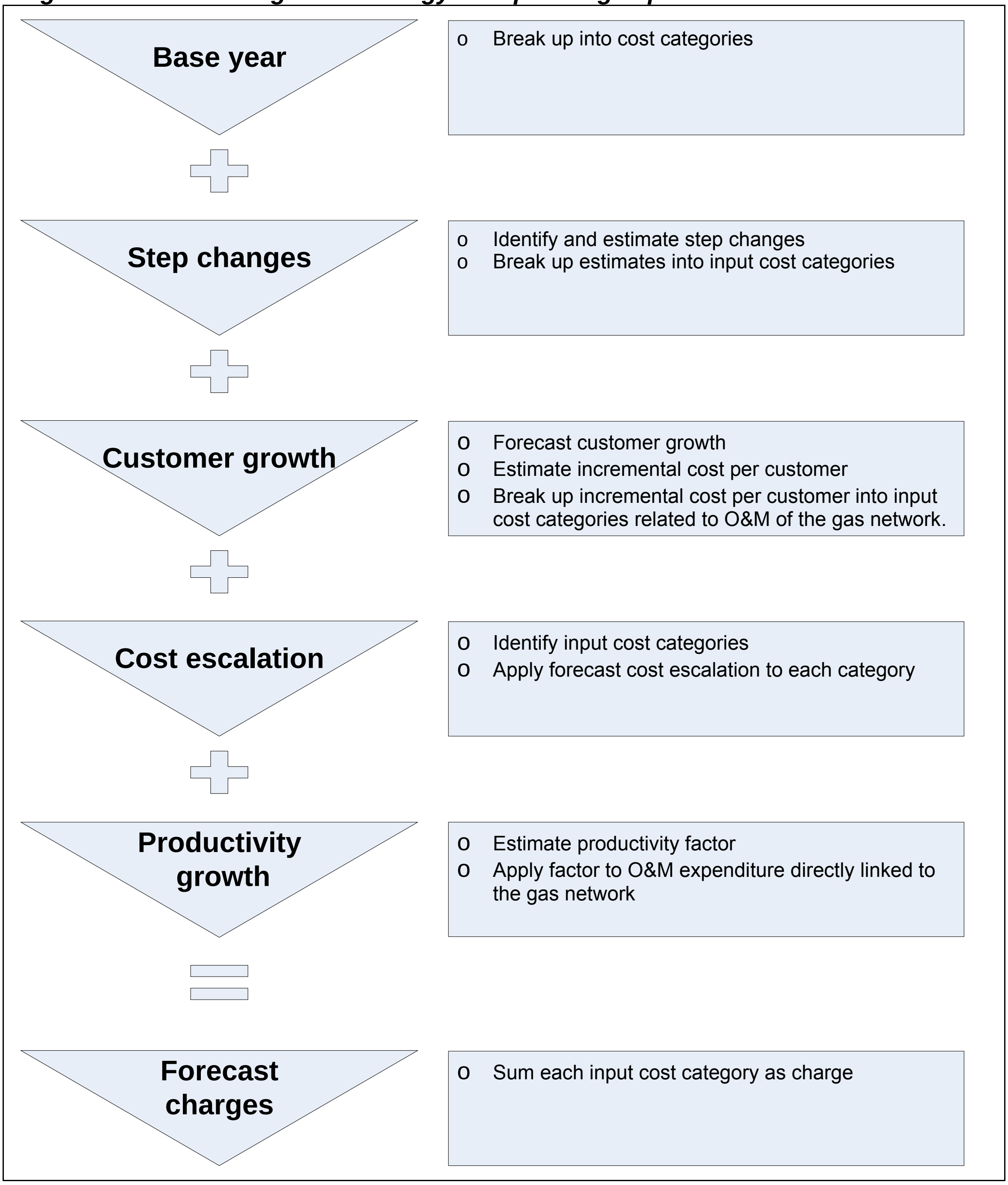
9.2.1 Forecast methodology and assumptions

ActewAGL Distribution has a *base year* approach to forecasting operating expenditure. The base year methodology requires:

- identifying an efficient base year and base year costs;
- adjusting for step changes including the removal from the base year of costs that are not indicative of future requirements and adding costs for new expenditures in future years, for example, those required to service new assets and network growth;
- accounting for growth in customer numbers;
- escalating costs for expected changes in input costs; and
- adjusting for productivity improvements.

Figure 9.1 provides a representation of the steps involved in the base year approach. The following sections explain the base year methodology including the adjustments made to base year costs. Section 9.2.1.1 describes the selection of the base year. Section 9.2.1.2 provides detailed discussion of step changes. Section 9.2.1.3 provides an explanation of how the costs have been adjusted for customer growth. Section 9.2.1.4 explains how the base year has been escalated. Section 9.2.1.5 explains the application of a productivity factor.

Figure 9.1 Forecasting methodology for operating expenditure



9.2.1.1 Determination of the base year

ActewAGL Distribution has chosen 2009/10 as the base year for undertaking forecasts for the access arrangement period. Operating costs for this year are already known by virtue of the negotiation of the Service Plan for 2009/10. ActewAGL Distribution therefore considers that 2009/10 is an appropriate baser year as it is the closest to the access arrangement period. ActewAGL Distribution has also chosen 2009/10 as the base year for corporate overheads costs given recent structural changes to this cost category (described below).

A benchmarking comparison study has been undertaken, which is included as attachment E to this access arrangement information. This study shows that, after normalisation of the data set for the dual main (both sides of the street) configuration of the ACT, Queanbeyan and Palerang gas distribution network and relative customer density, ActewAGL Distribution's costs are within the normal range of, or lower than, those of its peers. This is the case for each of the three constructed performance indicators based on the accepted drivers of operating and maintenance expenditure—length of mains, customer numbers and capital base—as summarised in Table 9.4.

Table 9.4 Summary of ActewAGL Distribution relative position on Indicators

Opex performance indicator	Relative performance
Opex / length of mains	Below the mean (in between the mean and the lower 95 per cent confidence interval)
Opex / customer	Below the mean (in between the mean and the lower 95 per cent confidence interval)
Opex / capital base	Below the mean (in between the mean and the lower 95 per cent confidence interval)

While the year in which costs are benchmarked (2007/08) is two years earlier than the year being proposed as the base year, a strong statistical inference can be made that the operating expenditure in 2009/10 year is highly likely to be efficient and also as efficient in 2009/10 as it was in 2007/08, for the following reasons:

- ActewAGL Distribution's performance indicators are between 5 and 25 per cent less than the mean for Australian gas network businesses; and
- The 95 per cent confidence interval for each of the performance indicators is between 19 and 58 per cent of the mean.

This level of relative efficiency would be expected to have been sustained and possibly enhanced. This is because, firstly, inherent in the operating expenditure path of ActewAGL Distribution is a 1.5 per cent per annum improvement in operating expenditure efficiency as a result of the agreement between ActewAGL Distribution and JAM to adopt the ICRC's approved operating expenditure. Secondly, for ActewAGL Distribution to lose its relative efficiency ranking, its costs would have to move:

- by between 5 and 25 per cent in two years to be at the mean position, and
- by approximately 60 per cent over two years before they would be above the upper 95 per cent confidence interval.

ActewAGL Distribution therefore considers that its relative performance on these indicators will not have changed significantly between 2007/08 and 2009/10 given its operating costs have increased only marginally over the intervening period. In support of this position, the exclusion of operating costs outside ActewAGL Distribution's control (UAG, government levies and the UNFT), and corporate overhead costs (significantly affected by the leasing of a new corporate headquarters), yields operating expenditure in 2009/10 only 5.5 per cent above the average for the six year period 2004/05 to 2009/10. This is despite growth of the network size and complexity including Bungendore and customer numbers over the period. ActewAGL Distribution also notes that operating costs in 2009/10 (after adjusting for the government levies, UNFT and UAG) are forecast to be lower than the allowance determined for that year by the ICRC in the earlier access arrangement. The 2009/10 expenditure levels used are consistent with the methodology for setting the fees and services provided by JAM in the earlier access arrangement period.

The forecast year 2009/10 has also been selected as the base year for corporate overheads. A forecast year has been used because the cost structure of ActewAGL's corporate overheads is undergoing significant changes. Importantly, the new ActewAGL corporate headquarters will be leased rather than owned by ActewAGL during the entire 2009/10 period. Accordingly, 2009/10 is more representative of future corporate operating costs and will improve the quality of the forecast for the access arrangement period.

9.2.1.2 Step changes

A step change in operating and maintenance expenditure typically results from the introduction or removal of an obligation or the adjustment of operating and maintenance programs or projects as the result of asset changes. Generally, a step change will result in a sustained departure from base year operating and maintenance expenditure, that is, a *step up* or *step down* in expenditure compared to the base year. In most cases, this is expected to be a permanent change and in some cases (such as pigging) it occurs periodically. These step changes arise because a new regulatory obligation or a new operating activity is required to operate the network prudently and efficiently.

The operating and maintenance expenditure forecasts discussed in this access arrangement information include step changes from two sources: those relating to expenditures by JAM under the DAMS Agreement and two relating to the direct expenditure by ActewAGL Distribution on gas network management. ActewAGL Distribution has identified five categories of changes that, when introduced, will impact as step changes on operating and maintenance expenditure over the course of the access arrangement period. Step changes have been identified for five categories of activity. The five step change categories identified are technical regulation, gas market operation, project specific costs, IT systems and finance and regulatory costs.

For the purposes of escalation, step changes have been broken down into assumed cost splits based on the information available regarding the expected cost of each step change or category of step change. The nature of the step changes in each category are discussed in the following sections and the cost-splits and cost for the step changes are provided in attachment N to this access arrangement information.

Technical regulation

As described in chapter 4, Australian Standards relevant to the operation and management of gas pipelines were reviewed by the relevant bodies over the course of the earlier access arrangement period with resulting operating and maintenance implications for ActewAGL Distribution. The relevant standards are:

- AS2885: Pipelines - Gas and liquid petroleum, known as the SAA Pipeline Code. As a result of the changes, AS2885 includes the requirement for Safety Management Studies (SMS) and integrity reviews. SMS require the operators of high pressure gas pipeline infrastructure to conduct regular workshops to ensure appropriate management of pipelines. The integrity reviews require periodic reviews of trunk main and primary main high pressure facilities. Based on the expected time to prepare and carry out the studies and reviews, compliance with the new requirements of AS2885 is expected to add to ActewAGL Distribution's costs;
- AS4645: Pipelines - Gas Distribution Networks, which, commencing 2008, includes the requirement to conduct Formal Safety Assessments (FSA). A FSA is a process to assess the safety of assets with a defined approach requiring a series of workshops. The cost of compliance with this new obligation is provided in attachment N. The estimate has been derived based on the expected time it will take to prepare and provide the required workshops.

Changed operating environment

The development of the national gas market has impacted on supply reliability in the ACT. This is due to a change in the behaviour of gas wholesalers, with market based incentives, that now only provide slim volume margins on pipeline supply in order to optimise their gas portfolio. On occasion this has resulted in low pressure at ActewAGL Distribution's pressure-controlled receipt point at Watson linked to the MSP. When the pressure at Watson transfer point drops below the level required to provide adequate supply to the ActewAGL Distribution network, a market shortfall event occurs. ActewAGL Distribution's alternative supply point, at Hoskinstown on the EGP, is not able to compensate for low pressure events at Watson as capacity on the EGP has been fully contracted.

Over the earlier access arrangement period, there have been, on average, two market shortfall incidents per annum requiring additional operational attention. ActewAGL Distribution forecasts that this frequency of supply incidents will continue over the access arrangement period. The step change assumes operational cost of managing two market shortfall incidents in field personnel, personnel for emergency incident meetings, network criticality analysis and load shedding.

Introduction of the Short Term Trading Market

As described in chapter 4, ActewAGL Distribution forecasts that a secondary effect of the expected introduction of a STTM hub at Sydney will be an increase in the frequency of market shortfall events on ActewAGL Distribution's gas network by an additional two per annum. This secondary effect will arise in response to the wholesale market focusing on deliveries through the Sydney hub. This is expected to constrain wholesaler's ability to provide gas to the ActewAGL Distribution network. ActewAGL Distribution's management options for this likely outcome are to increase the level of intervention in the wholesale market to ensure supply into the network, or, where this is not possible to manage the forecast two supply shortfall events as described above.

A further unintended impact of the STTM hub in Sydney is on the costs of management services for balancing gas. ActewAGL Distribution and JGN currently share a system known as CABS to manage retailers' supply into their networks. ActewAGL Distribution currently pays an incremental cost for this system. When JGN network receipts become managed under the STTM, some of the common elements of CABS will no longer be required by JGN. Consequently, ActewAGL Distribution will need to pay a larger portion of operating costs for CABS. In addition, with gas balancing arrangements for the Sydney hub being managed through the STTM, policy advice and market management services undertaken by JAM in respect of gas balancing under the gas market rules will no longer be shared with another service provider. Both of these changes are reflected in the operating expenditure forecasts through a step change in costs associated with the introduction of the STTM. These costs are the basis for this step change as shown in attachment N to this access arrangement information.

Project specific costs

Expanded scope of high pressure systems

Capacity development and/or stay in business drivers necessitate inclusion in the Asset Management Plan of eight major high pressure capital projects covering the access arrangement period. These eight projects fall into the following broad categories:

- **New or upgraded facilities.** The construction of major new facilities at Queanbeyan (a trunk receiving station) and at Tuggeranong (a primary regulating station) creates a requirement for additional regular maintenance. Upgrades to three facilities, Philip PRS; Watson PRS; and Fyshwick TRS, include the installation of additional runs or equipment requiring additional maintenance;[89]
- **Mains extension.** The additional length of primary main resulting from the Phillip to Tuggeranong primary main extension requires augmentation of existing activities on the mains. The major activities in this category will be cathodic protection and pipeline patrol;
- **Pigging**. Also part of the AMP is the addition of facilities to the trunk and primary systems to allow pigging (primarily, intelligent pigging) as the most cost effective means of ensuring their integrity as they age. Pigging facilities will include scraper stations on the Watson to Philip and Watson to Gungahlin sectors, and a launcher/receiver station on the Hoskinstown to Fyshwick trunk main. The pigging facilities, when not in use, require maintenance to protect them from deterioration and ensure their readiness for use.

[89] The engineering assessments for these projects (attachment Q) include specific project descriptions.

- **Integrity.** Following the construction of the pigging facilities these will be used to check the integrity of the pipelines. This includes hiring a contractor to carry out the analysis with the pigs and undertaking validation digs and associated repairs, if required. Integrity projects are described further below.

The base engineering estimates for these programs have been escalated to 2009/10 dollars by applying forecast annual inflation of 2.5 per cent.[90] The timing, original estimate, escalation and final estimates of additional operating and maintenance expenditure are summarised in Table 9.5. A more detailed project description and justification for the capital projects and methodology for deriving incremental operating and maintenance expenditure estimates is provided in the engineering assessments in attachment H to this access arrangement information.

Table 9.5 Additional operating expenditure for high pressure system scope changes

Maintenance program	Expected start date	Opex estimate ($2009/10)
Facilities		
Queanbeyan TRS	2011/12	43,260
Tuggeranong PRS	2013/14	14,660
Watson PRS Upgrade	2011/12	1,130
Philip PRS Upgrade	2011/12	2,360
Fyshwick TRS Upgrade	2013/14	16,610
Mains		
Tuggeranong Primary Mains Extension	2013/14	5,690
Pigging		
Canberra Primary Scraper Stations	2011/12	5,690
Canberra Primary Extension Pigging Facilities	2011/12	5,690
Main Integrity inspections		
Canberra Main Integrity	2011/12 and 2012/13 only	2,050,000
Hoskinstown-Fyshwick Main integrity	2011/12 and 2012/13 only	922,500

Note: the expected start date is the financial year following the capital budget year of the project. The operating expenditure estimate in 2009/10 dollars has been rounded to the nearest ten dollars

Canberra primary main integrity

The ActewAGL Distribution Canberra Primary Main was built in stages from 1995 to 2006 to provide for the safe and reliable supply of natural gas to Canberra and the southern ACT section of the distribution network. The pipeline was designed to be piggable but none of

[90] Forecast change from June 2009 to June 2010; see RBA, Statement on Monetary Policy, February 2009, Table 16.

the stations in Canberra currently have facilities to perform in-line inspections as this capital expenditure has been prudently deferred.

As a requirement of AS2885.3, the pipeline's maximum allowable operating pressure (MAOP) must be confirmed by establishing the condition of the pipe on a minimum of five year intervals. Based on current risk assessment, periodic integrity review, given the age of the assets, is now considered prudent.

The *Canberra Primary Main Integrity* project will facilitate data collection to use as a key input to confirm the MAOP of the Canberra Primary Main for the next pipeline review, due in 2011. Four options have been considered: do nothing; direct assessment; hydrostatic testing, and inline inspection. Inline inspection is considered the most effective, prudent and efficient option for measured pipe condition assessment to determine with a high degree of certainty pipeline integrity against the major threats of corrosion and third party interference. The cost for the project is $2.05 million split during 2011/12 and 2012/13. The engineering assessment is included in attachment H. ActewAGL Distribution has expensed this project consistent with its accounting policies (see the capitalisation policy at attachment Q to this access arrangement information).[91]

Hoskinstown-Fyshwick trunk main integrity

The integrity of the Hoskinstown to Fyshwick Trunk Main, constructed and commissioned during 2000 and 2001, raises similar issues to that of the Canberra Primary Main. The *Hoskinstown-Fyshwick Trunk Main Integrity* project will assess the findings of an inspection program to confirm the MAOP of the trunk main. The next pipeline review is due in 2011. Consistent with the Canberra Primary Main Integrity project, four options were considered and the inline inspection option was recommended as the most efficient solution. The cost of the program is $922,500 across 2011/12 and 2012/13. The engineering assessment is included at attachment H to this access arrangement information.

Accounting of main integrity projects

The main integrity inspection of pipes projects are considered repairs and maintenance in nature and are not to be capitalised consistent with ActewAGL Distribution's capitalisation policy (provided at attachment Q to this access arrangement information). ActewAGL Distribution's external auditors were consulted and confirmed the integrity projects are to be classified as non-capital works due to the physical inspection not extending the life of the assets. Any works following inspection that lead to remedial work being undertaking which extend the life of the asset will however be capitalised.

[91] It should be noted that the *construction* of pigging facilities is a capital project while the *use* of pigs for pipeline inspection and assessment incurs operating and maintenance expenditure.

Information technology

GASS Make Whole

The GASS system provides a suite of IT applications to ActewAGL Distribution in the key areas of:

- asset records;
- meter management and meter reading;
- billing;
- jobs management; and
- market participation and market management.

The system was developed by AGL prior to the structural separation of the gas industry but was subsequently modified to reflect the requirements of ring fencing, full retail contestability and the evolving gas market.

More recently, GASS was modified to account for the changing ownership of gas networks in the ACT and NSW. In October 2006, AGL's interest in ActewAGL Distribution was transferred to Jemena. As such, AGL moved to establish a new retail customer management system that is separate from Jemena (and therefore separate from ActewAGL Distribution). The required separation of GASS functionality was carried out through a project named *GASS Make Whole* which replaced the internal but ring fenced systems with external data interfaces and gateways between retailers and distributors. These changes to GASS require ongoing costs.

ActewAGL Distribution therefore faces increased costs through additional maintenance and due to it being allocated a greater portion GASS costs (which were previously shared with AGL). ActewAGL Distribution's allocation of GASS costs now reflect the relative portion of customer delivery point identifiers attributable to it in GASS (10 per cent).

Master SCADA

A SCADA system enables on-line monitoring and control of gas networks. ActewAGL Distribution and JGN share a SCADA system by virtue of contracting arrangements with JAM for both the ACT and NSW gas networks. The system was replaced in 2007 when its software was no longer supported by IT service providers.

JGN's predecessor, AGL Gas Networks, included the SCADA replacement expenditure for the IPART's approval in its 2004 proposed revisions to its gas access arrangement[92]. The IPART's consultants for the review subsequently agreed that the SCADA system was out of date, needed to be replaced and that the expenditure "was consistent with the amount that

[92] AGL Gas Networks, Proposed Revisions to Gas Access Arrangements, 12 January2004, pg 24. Other projects included the replacement of legacy systems as the Gas Accounting and Services System, the Asset Data Base Management, Field work management, Meter Management and IT and infrastructure system enhancement and hardware replacement.

would be incurred by a service provider acting efficiently".[93] The IPART subsequently accepted the expenditure for the 2004 access arrangement period.

The new SCADA technology uses personal computer rather than mainframe computer platforms. This results in increased operating expenditure due to support maintenance and licensing for desktop hardware and software. These costs are comprised of 80 per cent non-EBA labour and 20 per cent 'other' costs relating to licensing and telemetry. As JGN and ActewAGL Distribution share a SCADA system, ActewAGL Distribution's operating and maintenance costs have increased. The SCADA costs allocated to ActewAGL Distribution is based on the relative number of customer sites (measured as customer delivery point identifiers)—that is, a 90:10 split—between JGN and ActewAGL Distribution. The cost of this step change is provided at attachment N to this access arrangement information.

Finance and Regulatory costs

The following costs are directly incurred by ActewAGL Distribution.

Australian Energy Market Operator

As described in chapter 4, the new AEMO will commence from 1 July 200. It will take over responsibility of jurisdictional schemes such as the GMC for the operation of the NSW and ACT gas market functions. ActewAGL Distribution currently pays fees for the operation of the GMC, which will be transferred to the AEMO. The MCE has proposed that the current fee structure of the existing schemes provide the benchmark for the first year and potentially the following two years.[94] After this period it is likely that costs incurred by ActewAGL for the AEMO will be higher because of the expanded size and scope of the organisation and the complexity of its operations as compared to the GMC. This expected fee increase is reflected in a step change commencing in 2012. A mechanism to adjust for actual costs for this fee, as well as other externally imposed fees, charges, levies or taxes, is proposed as part of ActewAGL Distribution's tariff variation mechanism.

Regulatory submissions

The ICRC's final decision for the earlier access arrangement period included regulatory costs as a capitalised expenditure in non-system capital expenditure. Consistent with actual accounting practice and the AER's recent electricity distribution final determination for the ACT network, ActewAGL Distribution is proposing to depart from capitalising regulatory costs and instead treat them as an operating expense in the access arrangement period. Regulatory costs should be considered a step change in operating expenditure in 2013/14 and 2014/15 and are defined at attachment N to this access arrangement information.

[93] ECG, Review of AGLGN Gas Access Arrangement for Independent Pricing and Regulatory Tribunal, 30 August 2004, pg 81

[94] MCE AEMO Implementation Steering Committee, Australian Energy Market Operator Legislative Framework: Statement of Proposed Approach, August 2008, p iii

9.2.1.3 Customer growth affects on operating and maintenance costs

Operating and maintenance costs are directly and indirectly linked with the number of customers. This section explains the methodology developed to estimate how customer growth affects ActewAGL Distribution's costs.

For each additional customer added to the network, there are extra costs associated with servicing that customer. Some costs will have a one to one relationship with each customer; most obviously additional meter reading and billing. Many costs will increase in proportion to the addition of a number of customers so that five, 100 or 1000 customers need to be added before significant additional costs are incurred.

The addition of 1,000 customers, would increase costs at a customer call centre to support billing or technical failures inquiries and there would be a higher statistical probability of an emergency requiring attention of field crews.

Above a critical threshold of new customers, the network will also approach a point where capacity is limited. Under such circumstances, new capital (either new facilities or mains extensions) is required to support further growth. There will be operating costs associated with maintaining these new assets.

As demonstrated, a large range of activities need to be considered in attempting to capture the costs of additional customers. The average cost per customer captures all the costs in the examples above, from additional metering and billing to activities associated with facilities that support growth. Direct cost captures the immediate impact on costs from an additional customer, that is, the additional metering and billing requirements. The incremental cost per customer, which includes costs not noticed until there are a sufficient number of customers added, will lie somewhere between the average cost and the immediate cost.

Gas networks show economies of scale as the cost of servicing the next customer declines as the number of customers increases. A significant part of the economies of scale effect is associated with the capital component inherent with pipes and facilities infrastructure. However, there are also economies of scale within the operating expenditure of a network and economies of scope through management of corporate shared services.

Increasing economies of scale can not be experienced continuously. The relationship between costs and the number of customers would be expected to gradually 'flatten out' for a given network size. Figure 9.2 illustrates this expectation below. In addition, ActewAGL Distribution's network is ageing which gradually will require more maintenance to minimise life cycle cost.

Figure 9.2 Expectations regarding operating costs per customer

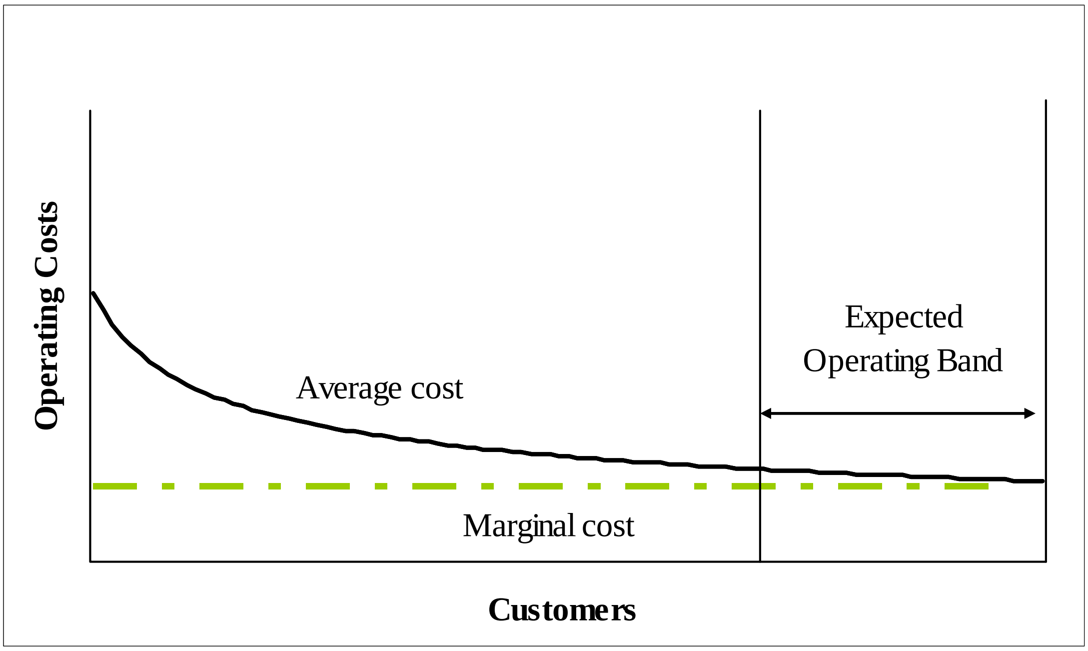


Figure 9.2 shows the difference between what is measured as ‘average’ cost and ‘marginal’ cost decreasing, for the operating expenditure associated with ‘normal’ growth (that is, excluding changes to the high pressure network). This is shown in the section of the curve marked ‘expected operating band’.

Although ActewAGL Distribution’s network is relatively small, its asset management contractor, JAM, provides services to a number of other systems, providing the opportunity to for operating and maintenance activities at a lower average cost. However, since there is a certain level of fixed operating costs associated with carrying out the business, not all costs would be expected to vary with the number of customers in normal growth circumstances (that is, only small numbers of customers are added during any year). This is because operating expenditure is comprised of a number of components, some of which are affected directly by customer growth and others affected by customer growth only indirectly, or at the margin. The latter costs would include corporate overheads such as legal, management, accounting/finance, regulatory and strategic support.

If only those categories of costs that are directly related to customers are divided by the number of customers serviced over the period (‘average direct cost’) this will approximate incremental cost. This approach requires removal of relatively ‘fixed’ operating costs, such as corporate overheads, management, planning, strategy, and so on, to reveal the ‘direct’ costs associated with customers related operating and maintaining costs.

Estimate of incremental cost (average direct cost)

As discussed above the average direct cost method calculates the average cost per customer for direct operating expenditure associated with the network. The direct costs include all ‘asset services’ costs excluding trunk and primary operating expenditure costs.

Costs included in the direct costs include meter reading, system monitoring and control, maintenance, etc. A full list of included activities in the direct costs is included in Box 9.1. This direct cost is then divided by the number of customers serviced over the observed period.

Box 9.1 Direct costs included in incremental cost per customer

The following work break down structure codes have been included in the 'direct costs' for the purposes of calculating an incremental cost per customer:

- SCADA service;
- Monitoring and control service;
- Planned maintenance:
  - SCADA;
  - Metering assets;
  - Meter data agent;
  - 1050 kPa pipework and facilities;
  - >1050 kPa pipework and facilities;
- Corrective Maintenance:
  - SCADA;
  - Metering assets;
  - Meter data agent;
  - 1050 kPa pipework and facilities;
  - >1050 kPa pipework and facilities;
- Fault response (response centre);
- Corrective R&M audit;
- Residential appliance audit;
- Non residential appliance audit;
- Urgent response;
- Planned:
  - Easement patrol;
  - Cathodic protection;
  - Leakage surveillance;
- Corrective:
  - Easement patrol;
  - Cathodic protection;
- Client support; and
- Client delivery supervision and management.

Operating expenditure increases associated with new assets on the trunk and primary systems are excluded since they are considered step changes. These increases relate to large step up in growth support requirements rather than the smooth addition expected over any given year. The additional operating expenditure associated with these trunk and primary capital changes are outlined in section 9.2.1.2.

Ideally the incremental cost would be observable by taking the change in direct costs year on year and dividing by the change in customer numbers over the same period. However, large changes in operating expenditure can be observed year to year due to the uneven distribution of asset ages and conditions (which affects maintenance cycles), the occurrence of network emergencies or through unforseen operating requirements. To smooth out these effects, a five year average was taken after adjusting for inflation.

Direct costs are collected based on the operating pressure of the pipe. These are categorised as being above 1050 kPa, equal to 1050 kPa and below 1050 kPa. Since all costs on the Trunk and Primary system are considered 'step changes', costs on pipes operating above 1050 kPa have been excluded. The remainder of costs are included in the average calculation.[95] Over the five year period the direct average cost per customer ranges from $29 to $34.7 (2009/10) with an average of about $32 (2009/10).[96] For the purposes of escalating this estimate through the period it has been assumed that 90 per cent of the cost component is EBA-labour and 10 per cent is other.

9.2.1.4 Escalation

The base year (2009/10) has been broken into input cost categories for the purposes of escalation. The categories are EBA labour, non-EBA and Other. These categories have been chosen based on the significance of the proportion of spending. In addition, each step change has been broken into the same categories so that they too may be escalated accurately.

Input cost splits would ideally be derived using historic spending information. For historic reasons JAM has not been in a position to provide a complete costing of providing services to ActewAGL Distribution. Such a project is currently under way. However, owing to the former Alinta's approach to accounting for each of its group companies, the recent history of the asset swap between Alinta and AGL, and the more recent acquisition of a majority of Alinta's infrastructure businesses the task has proven more difficult than originally envisaged. Consequently, JAM has not completed a compilation of historic costs to provide management and asset services to ActewAGL Distribution and therefore has not been able to derive an accurate cost split. Therefore JAM has approached this task using a combined conceptual and benchmarking methodology based on other gas distribution businesses and past observation to derive appropriate splits.

In the last Victorian gas access arrangement review (GAAR), Meyrick and Associates advised the distribution businesses of appropriate weights to be utilised in the rate of change formula. The rate of change formula is a method to roll forward efficient base year costs to establish operating expenditure forecasts. It included labour and non-labour escalators, productivity and growth. The proportion of labour recommended, and subsequently accepted, was 62 per cent leaving the non-labour component as 38 per cent.[97]

The Victorian weights were derived from previous work undertaken by Meyrick and the Pacific Economics Group, who advised the ESC during the review. The consultants' previous work had been undertaken for total productivity studies in the electricity and gas industries and the weights were not verified by the ESC due to the limited amount of information disclosed by the distribution businesses.

Given that the 62 per cent estimate for labour was derived using total operating expenditure information it would be expected that the labour share for the proportion of operating expenditure that JAM provides would be higher, given that government levies, UAG and

[95] However, three cost code categories have been excluded since they are not relevant for this calculation. They are customer chargeable work related to the bushfires (performed by Victorian Operations), other customer chargeable work and contestable metering costs.
[96] For all past years the June quarter CPI for the weighted average of eight capital cities was utilised. A forecast CPI of 1.5% was utilised for inflation between June 2008 and June 2009. A forecast CPI of 2.5% was utilised for inflation between June 2009 and June 2010. See RBA, Statement on Monetary Policy, May 2009, Table 16.
[97] ESC, Gas Access Arrangement Review 2008-2012: Final Decision – Public Version, 7 March 2008, p 235.

ActewAGL Distribution's corporate costs are not part of JAM's fees. Furthermore since there are two predominant sources of labour with different costs in the JAM business a further delineation is required.

Although JAM was unable to examine the total cost of providing ActewAGL Distribution management and asset services some direct costs were observed. That is, the costs of overheads and some unallocated costs were excluded. This cost information indicated that the majority of costs are labour related, ranging in weights from 93 per cent to 94 per cent over the 2007/08 and 2008/09 (including forecast) financial years. Apart from labour there are a number of categories JAM endeavoured to identify for escalation purposes. Initial investigations recognised property, communications and some materials as material elements. However, when included with preliminary overhead costs (*indirects*) these categories were clearly not material.

Therefore, JAM has examined each fee and has judged the input cost split based on the foregoing and the nature of the activities included in the fee, which is summarised in Table 9.6. The underlying assumptions for the cost split for each fee are summarised in the table below.

Table 9.6 Assumptions Regarding Input Costs, by fee

Fee	Activity Assumptions Affecting Input Costs
Asset Services	Majority of work undertaken by 'field' personnel, which are all on EBAs
	Supervision and management of 'field' personnel is carried out by personnel on non-EBA contracts
	Small proportion of materials costs required to carry out work, eg, petrol, lubricants, etc
Asset Management	All work carried out by personnel on non-EBA contracts
	Small proportion of materials used to support office based activities, eg, printer cartridges, paper, etc
Asset Utilisation	This is a capital related charge and is therefore not applicable
FRC	All work carried out by personnel on non-EBA contracts, majority of work is administration
	Small proportion of materials used to support office based activities, eg, printer cartridges, paper, etc
Marketing	All work carried out by personnel on non-EBA contracts
	Small proportion of materials used to support office based activities, eg, printer cartridges, paper, etc

Utilising the above assumptions the base year charges (2009/10) have been broken into input cost categories for the purposes of escalation. In addition, each step change has been broken into the same categories so that they, too, may be escalated. Table 9.7 provides a break down of each fee by input cost category.

Table 9.7 Base Year Charges Broken into Input Cost Categories

Charge	EBA Labour	Non-EBA Labour	Other
Asset Services	80%	10%	10%
Asset Management	0%	90%	10%
Asset Utilisation	0%	0%	100%
Contestability costs	0%	90%	10%
Marketing	0%	90%	10%

A summary of the escalation factors developed by CEG for JAM using the above methodology is provided in Table 9.8. The report is available at attachment J to this access arrangement information.

Table 9.8 Escalators (excluding CPI) used for operating expenditure (excluding corporate overheads)

Category	2010/11	2011/12	2012/13	2013/14	2014/15
EBA labour	1.3%	2.1%	1.9%	1.6%	1.8%
Non EBA labour	1.4%	2.1%	4.0%	4.4%	4.1%
Other	0.0%	0.0%	0.0%	0.0%	0.0%

Escalation of ActewAGL Distribution operating expenditure

ActewAGL Distribution corporate overhead expenditure has been escalated based on the actual proportion of wages, IT costs and Other. ActewAGL Distribution is aware that the AER used a general labour escalator developed by Econtech in its final electricity network determination in April 2009 because an Enterprise Agreement (EA) rate “would move ActewAGL Distribution from an incentive based framework to a cost of service recovery framework”. ActewAGL Distribution does not agree with this view. The framework has not moved just because a new regulatory period has started in the middle of a negotiated contract period. ActewAGL Distribution also notes that the EA is valid for its gas, electricity, and water and sewerage workforces: all of which have different regulatory and access arrangement periods. The current EA was negotiated at a time when there was a labour skills shortage. The previous EA was negotiated in a market with less of a labour shortage. However, the wage levels in the overhead expenditure were not adjusted upwards (above the EA escalation rate) due to the labour shortage increasing during the negotiated contract period of that agreement.

If the AER argument was to be strictly followed then EAs would be renegotiated every time there was a change in the labour skills shortage or in the general market. This would clearly add costs to the organisation due to the risk of industrial disputation and costs of EA negotiation making the organisation less efficient. ActewAGL Distribution has an EA in place which runs from 2008 and expires in June 2011. ActewAGL Distribution has therefore used the negotiated rate to escalate the overhead wage expenditure for the first year in the access arrangement period starting June 2010.

As noted in the ACT electricity network final decision in April 2009, the AER did not accept the business' developed escalators and applied new updated wage growth forecasts developed by Econtech. ActewAGL Distribution also notes that the AER expressed a preference to use state/territory specific forecasts.

Considering the AER's clearly expressed preference to use as current wage forecasts as possible, ActewAGL Distribution has not yet developed a new escalator report for corporate expenditure as more up to date escalators should be developed closer to the submission. For the purposes of this submission, ActewAGL Distribution has therefore applied the escalators in the report developed for the AER in March 2009 to the overhead wage expenditure for the second to fifth year of the access arrangement period commencing June 2011. ActewAGL Distribution own costs for engineers (being located in the ACT) have been escalated using the EGW escalators for the ACT from the same Econtech report. These costs are minor as a significant part of the expenditure for engineers is at JAM and located in Sydney. The wage escalators used are summarised in Table 9.9.

Table 9.9 General labour forecast wage escalators 2010/11 to 2014/15 for the ACT (real)

	2010/11	2011/12	2012/13	2013/14	2014/15
General labour	2.4%	1.0%	0.9%	0.2%	0.6%
EGW	3.6%	2.9%	2.5%	1.5%	1.5%

ActewAGL Distribution proposes that the most recent Econtech ANSIO report available prior to the final decision of the access arrangement period be used to escalate wages from 2011/12 and that the EA level of 5.0 per cent (nominal) should be applied in 2010/11. Econtech forecasts general labour compensation on a state/territory specific basis, which is consistent with the AER preference.

ActewAGL Distribution corporate overhead expenditure has also been escalated for increases in actual IT application costs and in other operating expenditure. IT application costs consists large of software licensing costs. Licence costs have increased substantially in the last few years causing ActewAGL Distributions licensing costs per unit to increase by approximately 30 per cent. ActewAGL Distribution expects this to continue during the access arrangement period and has therefore escalated the IT application costs as shown in Table 9.10. Other operating expenditure has been assumed to increase in line with CPI.

Table 9.10 Escalators for IT applications and other (real)

	2010/11	2011/12	2012/13	2013/14	2014/15
IT application costs	12.2%	13.3%	7.3%	7.3%	7.3%
Other	0%	0%	0%	0%	0%

9.2.1.5 Productivity on operating and maintenance costs

During the access arrangement period that commenced in 2000, a productivity factor of 3 per cent per annum was included in the approved operating expenditure. In the 2004 access arrangement period, the ICRC included a 1.5 per cent per annum productivity factor in its operating cost estimates. Over the period, ActewAGL Distribution and JAM have reduced operating costs by entering into third party agreements (for example, GIS mapping and meter reading). These productivity improvements represented about 2.5 per cent of the total JAM fees.

Based on benchmarking results and considering the history of productivity improvement over the 10 years of access arrangement regulation it is unlikely that there are further significant efficiencies to be pursued given the increased complexity of the network that is being serviced without cost increases.

However, some efficiency improvement due to technical innovation could be expected. For this reason, a productivity factor of 0.5 per cent per annum has been applied on all fees paid to JAM except the asset utilisation charge. This has been based on the historical productivity assumptions—3 per cent per annum in the 2000 access arrangement and 1.5 per cent per annum in the 2004 access arrangement. Based on this trend, a reduction of 1.5 percentage points every 5 years would result in the expectation of zero productivity improvement in the access arrangement period.

Given the significant 25 per cent reduction in real operating expenditure over the 10 year period between 2001 and 2010, further targeted productivity increases would not be a realistic expectation. ActewAGL Distribution has therefore applied an expectation of productivity improvement without identifying specific opportunities in the fees related to JAM. ActewAGL Distribution believes that the productivity increase of 0.5 per cent is a challenging target, yielding an overall increase in productivity of approximately 2.5 per cent over the period in what is a largely mature gas network with high uptake of the most current gas industry technology.

ActewAGL Distribution is taking on the risk of nominating efficiency improvements on the assumption that efficiency gains can continue to be achieved, albeit at a lower rate. This is an aggressive assumption for reasons set out in the benchmarking report (at attachment E to this access arrangement information) regarding declining opportunities for productivity improvement given the impact of 10 years of regulation. However, ActewAGL Distribution recognises the need to continue to be more productive in the interests of our customers.

Instead of applying a direct productivity factor to the costs directly generated within its own business, ActewAGL Distribution has assumed, consistent with the electricity final decision, no increase in employment over the access arrangement period. This treatment indirectly assumes an improvement in efficiency and employee productivity since the network is expected to grow substantially, the energy throughput to increase and customer numbers to grow by 14 per cent, while the number of employees remains constant.

Due to the uncertainties about future obligations and the growth of the network, ActewAGL Distribution has not been able to quantify this indirect assumed productivity gain, but notes that it could be substantial as no costs apart from the increased AEMO costs have been included in the forecast. It is likely, for example, that the new CPRS will entail additional administrative costs, to be achieved within existing staff numbers.

9.2.2 Forecast operating expenditure

Forecast operating expenditure for ActewAGL Distribution's ACT, Queanbeyan and Palerang gas distribution network is provided in Table 9.11.

Table 9.11 Forecast operating expenditure 2010-15

$ million (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Controllable costs						
Operating and maintenance	9.59	11.44	11.80	10.60	10.93	54.36
Corporate overheads	3.30	3.41	3.50	3.56	3.59	17.36
Non-system asset charge	0.52	0.52	0.52	0.52	0.52	2.61
Marketing	1.34	1.34	1.36	1.38	1.40	6.82
Other controllable costs	0.23	0.23	0.23	1.02	0.84	2.56
Total controllable costs	**14.98**	**16.95**	**17.42**	**17.08**	**17.28**	**83.71**
Other allowable costs						
Government charges	0.65	0.70	0.70	0.70	0.70	3.46
Utilities Network Facilities Charge	3.41	3.46	3.51	3.56	3.61	17.54
Contestability Charge	0.56	0.57	0.59	0.61	0.63	2.95
Unaccounted for gas	1.24	1.24	1.24	1.26	1.28	6.25
Other costs	0.26	0.26	0.26	0.27	0.27	1.33
Total other non-capital costs	**6.13**	**6.23**	**6.31**	**6.39**	**6.49**	**31.54**
Total operating expenditure*	**21.11**	**23.18**	**23.73**	**23.48**	**23.76**	**115.25**

* Excluding debt raising and self insurance costs

The following sub-sections describe each of the categories of costs and charges listed above in Table 9.11.

9.2.2.1 Operating and maintenance

Costs described as operating and maintenance costs above in Table 9.12 are a component of forecast operating expenditure. For simplicity these costs are taken to be those forecast to be incurred by ActewAGL Distribution under the DAMS Agreement with JAM. The JAM charges are incurred by ActewAGL Distribution for management and field services provided by JAM associated with the operation and maintenance of the ACT, Queanbeyan and Palerang gas distribution network. Expenditure in relation to IT support is for data maintenance of the GIS for the gas network. ActewAGL contracts Ecowise Environmental to provide this service and is directly paid by ActewAGL Distribution.

The operating and maintenance costs for the access arrangement period starting 2010/11 have been estimated as described in section 9.2.1 and are summarised in Table 9.12.

Table 9.12 Forecast operating and maintenance costs for the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Asset services	5.26	6.03	7.89	8.19	6.87	7.12	36.11
Asset Management	3.38	3.42	3.48	3.61	3.75	3.89	18.16
Productivity factor	-	(0.05)	(0.11)	(0.18)	(0.21)	(0.27)	(0.82)
IT Support	0.18	0.18	0.18	0.18	0.18	0.18	0.91
Total operating and maintenance costs	**8.82**	9.59	11.44	11.80	10.60	10.93	54.36

The operating and maintenance costs are forecasted to increase by 30 per cent corresponding to $12.5 million in the access arrangement period. The costs will increase in 2010/11 by $0.8 million mainly due to the step changes and in line with the escalators presented in section 9.2.1.4. The increase of $1.9 million in 2011/12 is due to the main integrity projects, explained in the step change section and in at attachment N to this access arrangement information. The inclusion of a productivity improvement is expected to offset the increase in costs by $0.82 million.

9.2.2.2 Corporate overheads

ActewAGL Distribution's ACT, Queanbeyan and Palerang gas distribution network business directly incurs a portion of the joint corporate overheads of the ActewAGL group. A range of central services and processes is carried out on behalf of TransACT, ACTEW Corporation and the business units within ActewAGL. The joint services originate from three different areas of the business as follows:

- Corporate Services, including:
  - Office of the Chief Executive
  - Internal Audit
  - Human Resources
  - Facilities Management
  - Legal and Secretariat
  - Corporate Finance
  - Business Systems & Commercial Development
  - Purchasing and accounts payable
- Retail, including:
  - Public relations
  - Media management and corporate brand management
  - Corporate sponsorship management

- Customer services through the Home Connect Stores

- Networks (Logistics) including:
  - Warehousing
  - Fleet management.

An annual cost allocation is undertaken for all joint costs arising from the above. The methodology is reviewed and cost drivers specific to each activity are applied. The cost allocation methodology is available at attachment Q to this access arrangement information.

In addition, and separate to the above, the cost of insurance premiums is allocated throughout the business on the basis of cost drivers specific to insurance. Insurance and marketing costs are discussed separately below. Corporate overhead's capital expenditures have not formed a part of ActewAGL Distribution's gas network capital base. A very small allocation, consistent with the other corporate overhead operating expenditure, for depreciation has instead been included in operating expenditure. The disposal of ActewAGL House in 2008 has therefore reduced the allocation of depreciation to gas networks.

The ActewAGL model for joint and shared services allows ActewAGL as a multi-utility service provider to access economies of scope and scale in these services that would not otherwise be available to single utility businesses serving the corresponding market. The efficiencies generated by this arrangement were measured by CRA International in January 2008. CRA International could demonstrate that ActewAGL Distribution was able to perform the functions significantly more cheaply than ACTEW as a stand-alone entity. ActewAGL Distribution is comfortable that similar efficiency gains are being realised by the ActewAGL Distribution gas Networks business reflecting the nature of multi utility structure operation, since the corporate expenditures are efficiently allocated across other parts of the ActewAGL joint venture. As described in section 9.2.1.5, ActewAGL Distribution has included further indirect efficiency gains through not assuming increased expenditure although the gas network will continue and grow and the introduction of new obligations such as the CPRS.

When forecasting other expenditure, ActewAGL Distribution has:

- reviewed historic costs and trends;
- applied escalation factors as described in section 9.2.1.4; and
- assessed regulatory requirements.

The forecasting approach adopted by ActewAGL Distribution for future other expenditures is that outlined in section 9.2.1.4 above. The shares of labour and miscellaneous costs are expected to remain the same as for the completed years in the current access arrangement period.

The costs of ActewAGL corporate overheads in the access arrangement period is summarised in Table 9.13.

Table 9.13 Forecast corporate overheads costs for the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Corporate overhead costs	3.30	3.30	3.41	3.50	3.56	3.59	17.36

The costs for corporate overheads are expected to increase by $4.7 million in the access arrangement period. A major reason for this is an increase of $1.2 million to reflect higher operating costs in relation to ActewAGL's new corporate headquarters from 2010. This impact arises primarily because the new corporate headquarters is leased, rather than owned by ActewAGL as was the case for the current corporate headquarters up until 2008. The financial justifications for the move were reviewed and accepted by the AER in its final decision of ActewAGL Distribution Electricity Network in April 2009. Increased costs for IT application explain $0.7 million of the increase.

Apart from these changes, the costs will increase in line with the escalators presented in section 9.2.1.4.

9.2.2.3 Non-system asset charge

The Non-system asset charge is paid to JAM for the return on and return of capital for non-system assets that were removed from ActewAGL Distribution's asset base when the partnership was set up. The assets, now owned by JAM, were for Agility to provide services to ActewAGL Distribution. The fee recognises that a return on those assets is prudent.

Its components are:

Asset utilisation = (depreciation + WACC) x RAB

Where:

- depreciation represents the return of capital;
- WACC is the weighted average cost of capital and is used to calculate the return on capital;[98] and
- RAB is the capital base.

It could be expected that the depreciation and WACC will remain constant over the period, leaving only the RAB to determine the rate at which the asset utilisation charge should escalate. The rate at which the RAB will change is given by the formula below:

RAB= carryfwd – depreciation + capex + indexation

Where:

- carryfwd is the value of the RAB at the end of the previous period;
- depreciation represents the return of capital;
- capex is the investment in capital for that period; and
- indexation ensures that the asset base remains in current dollar terms.

Since it is expected that capital expenditure will replace depreciated capital the remaining components of the formula are the carry forward amount and indexation. The carry forward

[98] The return on capital is calculated as the WACC multiplied by the value of capital that requires the return, in this case, the RAB.

is given by the previous period. The remaining component thus represents at what rate one would expect the RAB to change. Indexation is linked to CPI and so the asset utilisation charge will be escalated at this rate rather than the forecasting methodology outlined above.

The costs for the non system asset charge in the access arrangement period starting 2010/11 is summarised in Table 9.14.

Table 9.14 Forecast non system asset charge costs for the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Non system asset charge	0.52	0.52	0.52	0.52	0.52	0.52	2.61

The costs for the non system asset charge are expected to remain flat and not increase versus the earlier access arrangement period, accommodating for aged asset replacements from time to time.

9.2.2.4 Marketing and other controllable direct costs

Operating and maintenance expenditure, as defined in rule 69, specifically includes a reference to the inclusion of “expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services”.

Marketing expenditure includes marketing strategies, public safety campaigns, planning and performance and is to a large degree incurred by JAM. The costs have been estimated as described in section 9.2.1. Of the marketing expenditure 90 per cent has been escalated by the non-EBA escalator and 10 per cent by Other.

Other controllable costs consists of project related costs and regulatory costs. These costs have been escalated in accordance with the methodology described in section 9.2.1.4. Two step changes have been included in 2013/14 and 2014/15 due to the next regulatory submission as described in section 9.2.1.2.

The costs for marketing and other direct costs in the access arrangement period starting 2010/11 is summarised in Table 9.15.

Table 9.15 Forecast marketing and other controllable costs 2010-15

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Marketing	1.33	1.34	1.34	1.36	1.38	1.40	6.82
Other controllable costs	0.23	0.23	0.23	0.23	1.02	0.84	2.56
Total	1.56	1.57	1.58	1.59	2.40	2.23	9.38

The costs for network marketing will increase by 16 per cent in the access arrangement period compared to the prior five years, due to lower expenditure levels in the beginning of the earlier access arrangement period and the expected increase in the non-EBA escalator in order to cover public safety awareness. Other direct costs will remain in line with the expenditure level in 2009/10, but will increase significantly at the end of the period due preparation of the next access arrangement proposal. ActewAGL Distribution will include regulatory costs which were capitalised in the earlier access arrangement period of $1.4 million in 2013/14 and 2014/15 as described in the step changes section 9.2.1.2. Adjusted for the step changes at the end of the period, Other controllable costs are expected to increase by only 2.2 per cent.

9.2.3 Other allowable costs

9.2.3.1 Government charges

In 2006, the ACT Government introduced a UNFT. For the 2010–15 access arrangement period, ActewAGL Distribution has included in its operating expenditure forecasts an estimate of the UNFT payable to the ACT Government. It is difficult to accurately estimate future UNFT liabilities. Each year, the ACT Government provides the rate to apply for the coming year, but does not set the rate to apply to future years. The 2009/10 ACT Budget includes estimates for total UNFT revenue for each year to 2012/13.

ActewAGL Distribution has used the forecast growth in UNFT revenue from this source as a basis for estimating the UNFT applying to its electricity network. Estimated UNFT expenditures for the 2010–15 access arrangement period are shown in Table 8.17.

The Energy Industry Levy came into effect on 1 July 2007. The levy replaces licence fees associated with regulating the utility sector in the ACT. ActewAGL Distribution’s obligation under the Levy is estimated to be $527,000 in 2009/10 and has been escalated by CPI. A step change of $50,000 has however been included for AEMO in 2011/12 as described in the step change section. As noted above, these charges are all subject to an adjustment mechanism in the ActewAGL Distribution’s proposed tariff variation mechanism.

Government charges and the UNFT in the access arrangement period are expected to total $21 million as summarised in Table 9.16.

Table 9.16 Forecast government charges costs in the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Government levies	0.65	0.65	0.70	0.70	0.70	0.70	3.46
UNFT	3.33	3.41	3.46	3.51	3.56	3.61	17.54
Total	3.97	4.06	4.16	4.21	4.26	4.31	21.01

9.2.3.2 Contestability charge

This charge was introduced to reflect the additional services to support the day to day management of full retail contestability. Prior to the earlier access arrangement starting in 2004 these costs were passed through and included transitional elements such as establishing IT systems. The charge is paid to JAM.

The contestability charge has been forecasted applying the methodology outlined in section 9.2.1. Of the contestability expenditure, 90 per cent has been escalated by the non-EBA escalator and 10 per cent by Other.

The costs for the contestability charge in the access arrangement period are summarised in Table 9.17.

Table 9.17 Forecast contestability charges in the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Contestability charge	0.56	0.56	0.57	0.59	0.61	0.63	2.95

The costs for the contestability charge will increase by $0.3 million due to the expected increase in the non-EBA escalator. The productivity improvement factor of 0.5 per cent has been included in the forecast.

9.2.3.3 Unaccounted for gas

Unaccounted for gas is defined as the difference between the receipts (at custody transfer stations) and the deliveries of gas (measured by customer and operational gas meters) following correction for changes in the quantity of gas stored in the pipeline. UAG is caused by a variety of factors such as leakage from the system, metering error, theft and inaccuracy in the conversion from quantity of gas measured to energy. Any pipeline system will to incur some amount of UAG, due at least to the measurement uncertainties. Understanding of these uncertainties is pivotal in understanding UAG.

UAG is typically expressed and reported as a share of receipts. The relationship between UAG and its main components is summarised in the following formula:

$$\text{UAG} = \Sigma\ \text{Receipts} - \Sigma\ \text{Deliveries} + \Delta\ \text{Linepack} = \text{Metering Uncertainty} + \text{Billing System Uncertainty} + \text{Leakage} + \text{Theft}$$

The efficient level of UAG for a particular gas network will depend on a number of variables that are unique to each gas network. Estimating this efficient level is subject, similar to all measurement and estimation processes, to uncertainty.

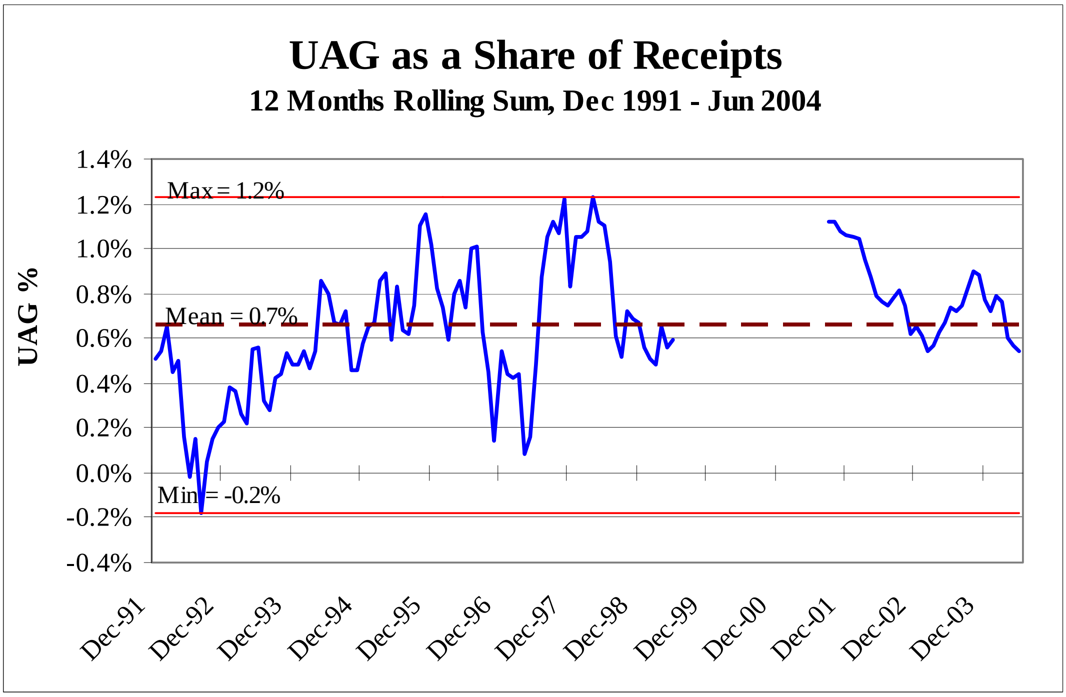
ActewAGL Distribution considers that it is being inappropriately penalised by the unsustainably low allowance for UAG of 1 per cent of receipts in the earlier access arrangement period. Based on its analysis of the circumstances of its network and a range of factors that affect UAG, ActewAGL Distribution estimates that the level up to which UAG can be efficiently controlled is 1.8 per cent of receipts. This level fits well within the range of levels of UAG experienced by similar networks, both within Australia and overseas.

ActewAGL Distribution's historic UAG performance

At that time of introduction of natural gas to the ACT in 1982, UAG on the network was not measured. Technology for this purpose was introduced and measurement of UAG commenced in January 1991. From July 1999 to Sep 2000, UAG measurement was again interrupted due to an IT systems changeover. This is reflected in Figure 9.3 which shows historic UAG performance on the network from December 1991 (the first available 12-month rolling sum measurement) to June 2004.

UAG was volatile in the period prior to the IT system changeover in 1999/2000. After the introduction of the new system, volatility materially decreased. As shown in Figure 9.3, during the period of December 1991 to June 2004, UAG in the ACT fluctuated between approximately -0.2 per cent and 1.2 per cent of receipts, with a mean of 0.7 per cent.

Figure 9.3 UAG in the ACT 1991-2003



In the access arrangement for ActewAGL Distribution's (then) ACT, Queanbeyan and Yarrowlumla network approved in January 2001, the level of UAG was set at 0.7 per cent for each year of the access arrangement period, which extended to June 2004.[99]

For the earlier access arrangement period (July 2004 to June 2009), ActewAGL Distribution proposed that the level of UAG be set at 1.5 per cent of gas receipts. ActewAGL maintained that this assumption was reasonable based on historic measurements of UAG and the accuracy range of metering equipment of ±2 per cent. In its draft decision, the ICRC rejected ActewAGL proposal and advanced its own UAG estimate of 1 per cent. ActewAGL subsequently did not oppose the ICRC estimate which has been applied in every year of the earlier access arrangement period.

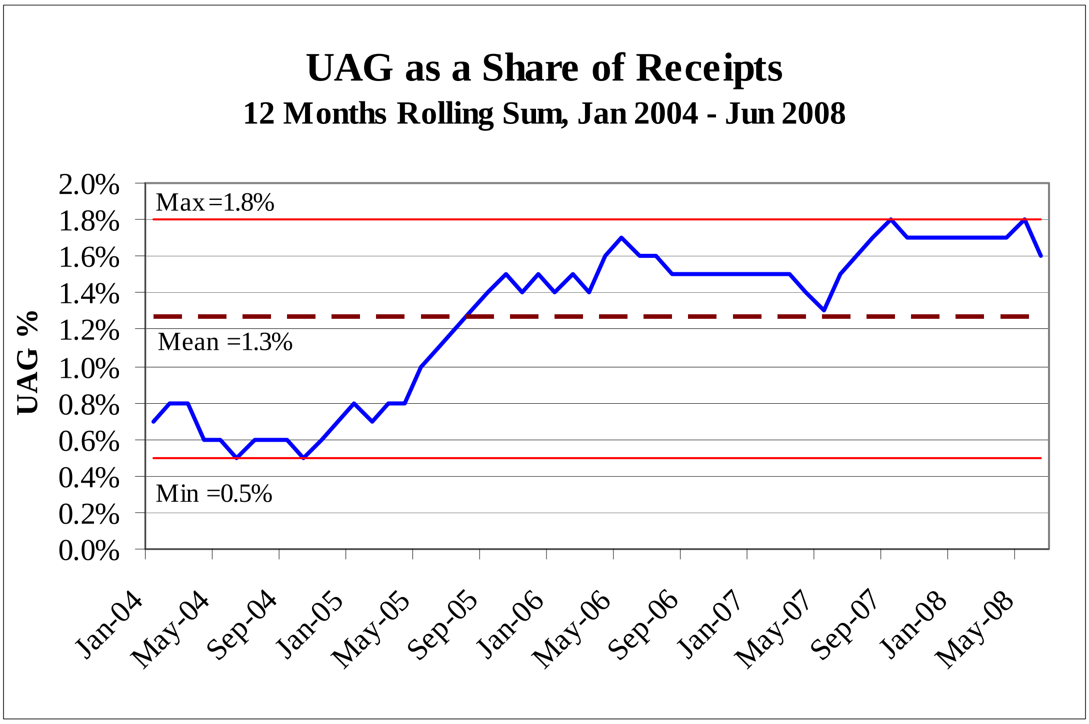
Over the course of the earlier access arrangement period, UAG has fluctuated between 0.5 and 1.8 per cent of gas receipts, with a mean of 1.3 per cent. ActewAGL Distribution's measurements of UAG in the earlier access arrangement period are shown in Figure 9.4

[99] ActewAGL Distribution, *Access Arrangement for ActewAGL Distribution System in ACT, Queanbeyan and Yarrowlumla*, 17 January 2001, p.38

shows that UAG increased from the average between January 2004 and April 2005 of 0.7 per cent to 1.5 per cent in October 2005. Thereafter, UAG was less volatile with the average of 1.6 per cent through the remainder of the period shown.

This is materially higher than the level of UAG experienced historically in the ACT. However, as explained further below, the measurement of UAG is subject to a significant degree of uncertainty resulting from metering and billing system uncertainties and losses from the gas network. Therefore, it is not unusual to observe volatility in UAG measurements.

Figure 9.4 ACT UAG in the earlier access arrangement period



ActewAGL Distribution conducted a detailed investigation of the causes of increased UAG between 2005 and 2008. Causes of the trend increase UAG on the network were determined as:

- the impact of moving from one to two network receipt points in 2002 and a shifting of the supply balance between these two over the subsequent period. As a result of the implementation of a point of supply from the EGP at Hoskinstown, gas receipts at Watson CTS (from the MSP) have declined from representing 100 per cent of receipts to approximately 50 per cent. The share of total receipts at Hoskinstown CTS has increased from 0 to approximately 50 per cent in the same period;
- the installation during 2006/07 and increasing use of four WBH at Hoskinstown CTS. These currently consume approximately 12 TJ of gas per annum—about 0.2 per cent of Hoskinstown CTS receipts—in their operation and, until recently, their gas consumption was unmetered; and

- the prudent extension of customer meter lives but with associated reductions in accuracy and increased numbers of undetected, non-registering meters.

Each of these is explained further in the series of boxes which follow.

Statistical modelling indicates that a reasonable range for ActewAGL Distribution's UAG is up to 1.8 per cent. This modelling and detailed discussion around the definition, measurement and sources of UAG is discussed further below.

In view of the trend increase in UAG during the earlier access arrangement period, ActewAGL Distribution is proposing changes to the method by which it is required to account for UAG during the access arrangement period.

ActewAGL Distribution proposes that, for the access arrangement period the approved (efficient) level of UAG for the ACT, Queanbeyan and Palerang network be 1.8 per cent of receipts.

As the price of UAG is not a matter that can be controlled by ActewAGL, Reference Tariffs should be allowed to be varied consistent with the actual price of UAG at the time of annual tariff variations on the basis that ActewAGL has demonstrated that it has used reasonable endeavours to purchase gas at the lowest available prices. A methodology similar to that in JGN's 2004 access arrangement provides an example of a useful approach. ActewAGL Distribution therefore further proposes that:

- the purchase price of UAG be passed through in reference tariffs based on ActewAGL's actual purchase price on the condition that ActewAGL a has undertaken a sound commercial process designed to achieve the lowest available price in the market;[100] and
- tariff adjustment mechanisms be approved for variation in the actual price of UAG from the forecast price.

The base costs of UAG included in the operating expenditure forecasts for the access arrangement period as shown in Table 9.18.

Table 9.18 Forecast unaccounted for gas costs in the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Unaccounted for gas cost	0.74	1.24	1.24	1.24	1.26	1.28	6.25

[100] Based on the most recent tenders for UAG, the forecast price for UAG be $8.75/GJ ($2008/09)

Box 9.2 Consumption by water bath heaters

On the ActewAGL gas network, water bath heaters are installed at the Fyshwick and Hoskinstown custody transfer stations. In addition, a smaller WBH unit supports the Bungendore pressure off-take station. The new Queanbeyan TRS including WBH is scheduled for completion in 2010/11.

WBHs consume certain quantities of gas flowing through the pipeline so as to perform their functions (discussed above). Thermal efficiency of large heaters can be around 75 to 80 per cent, but smaller heaters are less efficient.

The need to collect internal consumption by WBHs after their installation was not identified. However, ActewAGL identified this oversight and began measuring the WBH load in April 2008.

An adjustment to UAG for WBH consumption has been implemented since April 2008. For the period 01/04/2008 - 31/12/2008, WBH consumption on the ActewAGL gas network was estimated at 16 TJ. This could increase to 19-20 TJ for the full year. The current expectation is that the reduction in UAG due to the WBH adjustment would equal up to 0.2 per cent, depending on gas demand and ambient temperature.

Sources of UAG

Although some UAG on the ActewAGL Distribution network will inevitably arise though leakage, theft and unmetered operational use of gas, the main drivers of UAG and UAG uncertainty on the network are related to metering. The main metering issues are:

- uncertainties around receipt meter measurements;
- uncertainties around delivery meter accuracy;
- impact of delivery meter degradation and failure; and
- billing system uncertainties.

Inaccuracy in the conversion from quantity of gas measured to energy, reflecting discrepancies in temperature, pressure, heating value, altitude or the gas compressibility factor is also a factor.

Metering uncertainty

The uncertainty of gas measurements (both at injection into and withdrawal from the network) is one of the main contributors to UAG. Even though installed field meters are checked and calibrated by their manufacturers before being supplied to the network business, there are many reasons why meters might lose their calibration once installed on site. For instance, the calibration medium, and the pressure and temperature in the field are usually different from the factory calibration conditions. Any change in density, pressure or temperature will have an effect on the quality of measurements.[101]

There is inherent uncertainty associated with each of the meter types used by a gas pipeline or networks. The main characteristics of various meters typically deployed by gas pipelines and networks are set out in Box 9.5. Gas network businesses apply criteria for selection of the most appropriate meter type to adopt for the load it is to measure. Inherent

[101] Rudroff, Daniel, *Gas Meter Proving Can Ensure a Healthy Bottom Line*, Pipeline and Gas Journal April 2001.

in these selection criteria will be the cost and benefit of increasing accuracy associated with each meter type.

Box 9.3 Shift in supply balance between Watson and Hoskinstown

In winter 2002, ActewAGL completed construction of a trunk main extending the ACT network to connect with the EGP between Fyshwick and Hoskinstown. A meter station was installed at Hoskinstown to measure the receipts from the EGP.[102] The measurement is performed using an ultrasonic meter, which measures the speed of gas movement by reference to the speed at which sound travels in the gaseous medium within the pipe.

Even though the exact impact of interconnecting with the EGP on the level of UAG is not known, it is known that the Watson and Hoskinstown metering facilities have dramatically different measurement characteristics due to significantly different flow conditions being measured. It is also known that flows from the EGP into the ActewAGL network increase the range of flow rates over which the Watson meter is required to operate. Hence, it is reasonable to expect that the shift in balance between the Watson Custody Transfer Station and through the Hoskinstown Custody Transfer Station is associated with changes in levels of UAG. It is also known that increased use of the Hoskinstown Receipt Point will increase the amount of gas used to operate the WBHs at Hoskinstown and at Fyshwick. As identified above this has been taken into account in UAG measurements since June 2008

ActewAGL undertook some analysis to further examine this relationship. Figure 9.5 compares measurements of UAG (as a share of total gas receipts) to the measurements of gas flow through the Hoskinstown CTS (also as a share of total gas receipts through the pipeline network) for the most recent period, October 2005 to October 2008.

From Figure 9.5, it is clear that there is a correlation between the two variables – UAG tends to increase where the balance of flow between the Hoskinstown CTS and the Watson CTS moves towards Hoskinstown. The correlation between the two variables is 0.746. The R^2 of the line fitted through the data is 0.5565, meaning that for this particular sample, variation in gas flows through Hoskinstown explains 55.65 per cent of variation in the measurements of UAG. The remaining 44 per cent is due to other factors that contribute to UAG.

These results are important enough to suggest that the introduction of the Hoskinstown CTS to the ACT gas network may have contributed to the increase in the level of UAG over the period 2004-2008. However, additional studies are required to better understand this phenomenon.

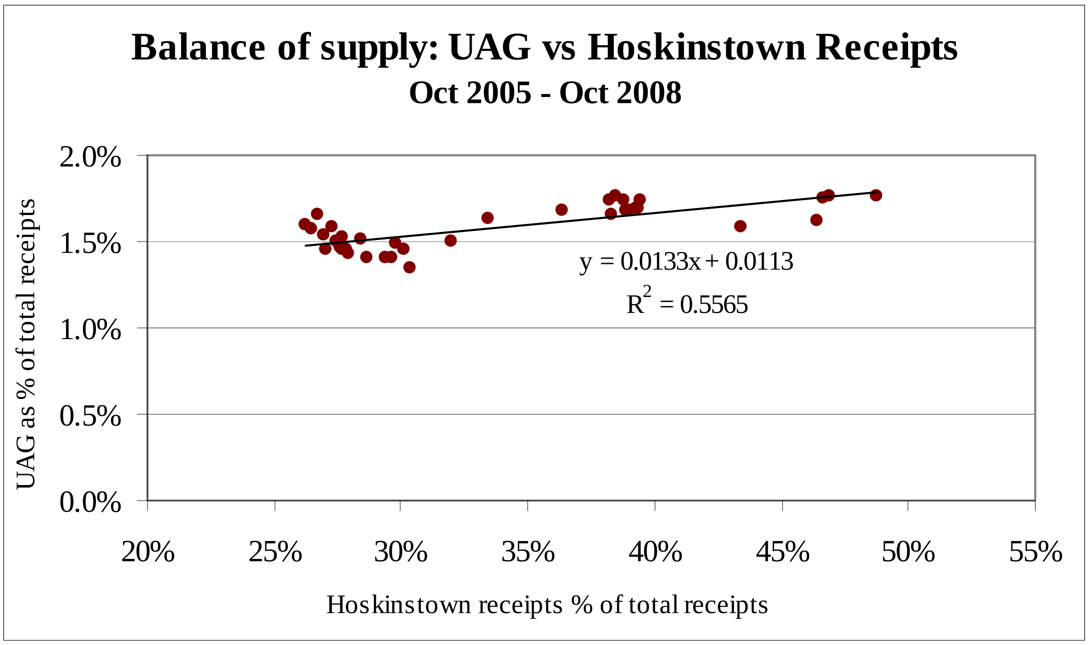
This result is unsurprising because the receipt meters will be within ±1 per cent accuracy, but each meter will be at a different point of accuracy within this range. The result is that the UAG will vary depending on the proportion of gas flowing through the two receipt meters (CTSs). It is important to note that this does not imply that either CTS is inaccurate (i.e. outside the acceptable accuracy level, but that small systematic differences in metering accuracy between the two CTSs will register as a relationship between the level of UAG and the balance of receipts.

Unmetered WBHs will impact of variation in gas used in WBHs and be part of the relationship between the balance between the level of UAG and the balance of receipts between Hoskinstown and Watson.

The commencement of measurement of gas consumption on WBHs can be expected to not only reduce he overall level of UAG, but also this relationship.

[102] Sheila Krishnan, *ACT Gas Network – An Efficient Evolution*, Agility Management Pty Ltd.

Figure 9.5 UAG compared to the measurements of gas flow through the Hoskinstown CTS



Box 9.4 Meter ageing and the extended meter life program

The ageing of the various types of meters used on the ActewAGL network may also contribute to an increase in UAG. This is driven by the fact that meter accuracy decreases over time while still remaining within the approved accuracy bounds.

The statutory asset life for ActewAGL's residential meters is 15 years. Life extension can be obtained beyond 15 years following satisfactory statistical testing of individual meter populations.

Statistical sampling of the installed meter population reaching 15 years of service confirmed that an acceptable proportion of the population passed the statutory accuracy requirements. The life of these meters has therefore been extended and they remain in service. Following the introduction of the new Australian Standard AS4944:2006 meter lives may extended by 5 years compared to the previous extension period of 10 years. The ACT and NSW regulatory bodies have approved the extension of meter lives following ActewAGL's fulfilment of the requirements of the Standard.

In 2011, the first of the life-extended meter populations will become due for assessment. It is not planned at this stage to seek a further life extension for these 25-year old meters.

As failure modes of diaphragm meters can be for them to read "fast" or "slow" the main impact of the extended meter life program will be to increase the uncertainty range for residential meter accuracy. However, a further effect of extending meter lives will be to increase the number of undetected non-registering meters with a consequent increase in UAG[103]. ActewAGL has not been able to quantify the effect of the meter life extension because the number of non-registering meters that are not detected cannot be known. However, given that the extension began in 2004/05, it is reasonable to expect a gradual increase in UAG from that time for extended meter life despite systems to identify non-registering meters.

[103] ActewAGL Distribution has a program to identify non-registering meters. However, it is recognised that not all non-registering meters will be identified, because the methods used require scanning of meter readings which will lead to delayed or non identification of some non-registering meters.

Box 9.5 Characteristics of meters deployed in gas pipelines and networks

Diaphragm or bellows meters are the most common residential/ small commercial customer meters with gas flowing through two or more chambers that alternately contract and expand producing a near-continuous flow of gas. This flow may be translated into electrical pulses for electronic recording/ readout. Residential meters are normally read visually from the index without using a pulse output.

Within **rotary meters**, two figure-eight shaped lobes (the rotors) spin with precise alignment. With each turn, they move a specific quantity of gas through the meter, which may then be recorded via electrical pulses to a flow computer, or by visual reading of the index.

Turbine gas meters infer gas volume by determining the speed of the gas moving through the meter. The speed of the gas, adjusted by a calibration or "K" factor, is transmitted to a mechanical or electronic counter.

Orifice meters consist of a straight pipe inside which a precisely known orifice affects the flow of gas. These meters are called inferential meters because they infer the rate of gas flow by measuring the pressure difference across a deliberately designed flow disturbance. The gas pressure, density, viscosity, and temperature must be measured in addition to the differential pressure.

Ultrasonic meters are more complex than mechanical or orifice plate meters as they measure the speed of gas movement by reference to the speed at which sound travels in the gaseous medium within the pipe. They are inferential meters.

Metering uncertainty is exacerbated by meter damage due to occasional mishandling and incorrect installation; and it is difficult to identify faulty meters due to variability of gas usage patterns, their large number, their geographical dispersion and inability to verify them on site.

ActewAGL achieves the standard of accuracy of gas measurement required by the ACT Gas General Metering Code and specified by the ACTPLA by:

- selecting measuring equipment that is capable of measurement with prescribed accuracy under the expected conditions;
- calibrating equipment to the acceptable tolerance using calibration equipment of appropriate precision and traceable to relevant National Reference Standards; and
- operating and maintaining measurement equipment in accordance with the appropriate procedures.

ActewAGL does not have direct control over the transmission pipeline operators' measurement equipment at custody transfer stations, but ensures accuracy in gas measurement to the extent possible through:

- approval of new or modified measurement systems including instruments, calculations, data communication, calibration and maintenance schedules, etc;
- witnessing scheduled and *ad hoc* calibrations; and
- verification of unwitnessed calibrations.

As part of the network purchasing program administered for ActewAGL Distribution by JAM, gas meters are required to be accurate to within ±1 per cent or less. However, this range will increase with factors such as meter age, loss of accuracy of meter regulators, and changes in throughput from the original design conditions. The *NSW Gas Supply (Gas Meters) Regulations 2002* allow customer meters to be within the accuracy range of +2 to –

3 per cent. ACTPLA has approved a similar range for ACT meters. For pipeline custody transfer applications, acceptable target errors used by industry are tighter—generally less than ±1 per cent—but this varies depending on flow rate range. However, meter accuracy changes with age. As a general trend, meters under-read (that is, read *slow*) as they age. This is more likely to be the case with meters at delivery points than at custody transfer stations because of real time monitoring and regular calibration of custody transfer meters.

Diaphragm meters may read slow or fast as they age, depending on the mode of degradation of the meter[104]. However, a proportion of these meters also stop registering before they reach their expected life after 15 years (or 20 years with a life extension program). Most non-registering meters are detected within one or two billing cycles but, for those that are not, the contribution to UAG is 100 per cent of their unmetered throughput.

Mechanical meters (rotary or turbine) tend to under-register as they age due to bearing wear and the associated increased drag. While both meter types will have higher under-registration at low flows, this is particularly a characteristic of turbine meters which would be measuring larger flows that rotary meters.

Orifice plate meters have no moving parts but, because they rely on pressure loss across the orifice, fouling of the orifice may increase the pressure drop and cause meters to over-register or, if the flow pattern upstream of the orifice plate is disturbed, to under-register. On the other hand, low flows through an orifice plate imply very low, difficult to measure, pressure drops. Orifice meters have a narrow accurate flow range, and tend to under-register at low flows.

The measurement bias of ultrasonic meters is more difficult to predict because they rely on more complex measurement processes (as described in Box 9.5). Meter biases may change over time as they may be related to flow, pressure, temperature, meter age or gas composition. Imperfections in heating value application may also cause biases in determinations of the energy flows.[105]

Industrial and commercial (I&C) meters have the same statutory life as residential gas meters. However, ActewAGL Distribution replaces rotary and turbine meters more frequently to ensure accurate billing of larger loads and to reduce the incidence of loss of supply due to meter failure. Meter replacement periods for I&C customers are:

- 5 years for turbine meters;
- 10 years for rotary meters; and
- 15 years for diaphragm meters.

Based on its experience and that of JAM, ActewAGL Distribution estimates the impact of meter degradation errors for each delivery meter type at the time of replacement to be as shown in Table 9.19.

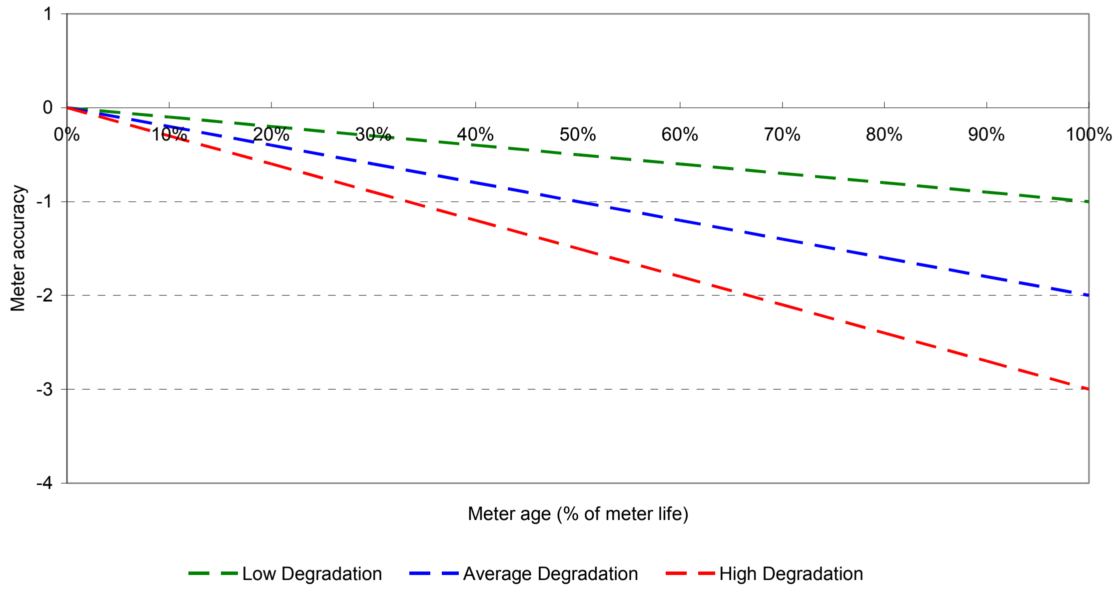
[104] Diaphragm meters typically have two modes of degradation: (1) diaphragm shrinkage where meters over-read and (2) valve leakage where meters under read
[105] VENCorp Un-Accounted-for Gas (UAFG) - Explanatory Notes, p1 www.vencorp.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=717&doc_id=713

Table 9.19 Impact of meter degradation errors for each delivery meter type at the time of replacement

Meter Type	Expected level of meter degradation	Comment
Turbine	-2.0%	
Rotary	-0.5%	
Diaphragm	-0.2%	Due to meters going NR

Figure 9.6 illustrates a model to estimate a likely range for the impact of meter degradation. The model assumes that meters will degrade their accuracy by 2.0 per cent over their life with an uncertainty about this estimate of ±1.0 per cent, and that the pattern of degradation is linear. This assumption of linearity is reasonable without empirical measurement. It also assumes that the average life of the population of meters is approximately half of the full life of meters. Accordingly, the model would estimate that the level of metering accuracy would be half that of a meter at replacement age. On a similar assumption that the estimate of the degradation of meter accuracy is 2 per cent (±1.0 per cent) at the end of its life the reduction of meter accuracy for the population of meters will be 1 per cent (±0.5 per cent).

Figure 9.6 Model to estimate a likely range for the impact of meter degradation



On this basis and given the mix of meters on the network, ActewAGL Distribution estimates that the effect of meter degradation on UAG can be reasonably estimated at 0.6 per cent, with an uncertainty range of ±0.3 per cent.

Billing uncertainty

All gas transactions are based on the energy content of gas supplied. Energy content is calculated by multiplying the volume of delivered gas by its heating value (HV). Because gas is compressible, the volume of gas measured by a meter is converted to standard volume, that is, its volume at standard conditions (temperature of 273.15°K and pressure of 101.325 kPa). To achieve this, gas temperature and pressure need either to be measured or assumed.

For large gas users, it is feasible to measure all gas parameters (volume, pressure and temperature) by installing flow correctors and data communication equipment to calculate daily gas consumption. For smaller gas users, usually less than 23 TJ/year a *fixed factor billing* approach is used, where gas pressure is controlled by a regulator and gas temperature and atmospheric pressure is estimated based on published long-term averages from the Bureau of Meteorology. The fixed factor billing approach leads to a degree of uncertainty.

System losses

System losses include such items as unavoidable loss of gas by purging pipelines, hits on mains and losses from other equipment; replacing and repairing gas mains and testing service lines during meter replacement.[106] Losses also include leakage of gas from the system, any unmetered gas used for operational purposes, and theft.

Leakage and gas theft

Apart from losses of gas from purging and hits on mains, leakage from distribution networks using modern materials and jointing techniques (as used in the ActewAGL Distribution network) is typically small, because it involves gas escaping through minute holes. In addition, leaks of any size are likely to be detected because of the effect of odorant that enables gas to be smelled, even at low concentrations. This kind of leakage is relevant to leaking pipes and pipe joints, above-ground fitting connections and venting of gas regulators. Leaking fittings, along with excessive regulator venting, is usually reported by the public and addressed in a timely manner. Leakage is much more prevalent for older cast iron mains.[107]

A significant proportion of reported leaks are associated with meters and regulators. Regulators are designed with relief valves that vent gas into the atmosphere in the event of the downstream pressure rising above the metering pressure. These sorts of events are not common, but with age regulator relief valves may leak. If leaks from relief valves are small, it may take some time before they are detected and replaced.

Gas theft is regarded as uncommon and of small impact on UAG.

Gas used for operational purposes

This category contains gas used for commissioning/decommissioning of gas mains and the water bath heaters.

When gas travels from high to low pressure areas, it cools quickly. The degree of cooling depends on the starting temperature and pressure, final pressure and gas composition. If

[106] J.M. Pickford and F.E. Vandaveer, Unaccounted-for Gas, Chapter 12, *Gas Engineer's Handbook*
[107] There are no cast iron mains in the ACT

water content of the gas is high enough and the final temperature is low enough, ice or hydrate can form at the regulator outlet. Solids formed in this way may block gas flow directly, or do so by clogging downstream equipment. This is particularly relevant in winter when ground temperatures are low. Preheating of gas using a water bath heater before letdown can avoid these problems.

The amount of gas used by water bath heaters as a share of throughput is typically small. This contribution can be eliminated by metering WBH usage and including the quantities measured as gas delivered and accounted for as system use gas. However, it is significant enough to affect the amount of UAG if not measured and included in the UAG calculation. (This issue is further addressed below in the context of ActewAGL Distribution.)

Estimation of a likely range for UAG in the ACT and Queanbeyan

The level and range of UAG are dependent on the characteristics of each individual network.

UAG is a sum of uncertainties, which may have either positive or negative impact. A low value of UAG, especially over a short period of time, does not necessarily mean that all measurements within a network are accurate. It may be the result of quite large values of opposite signs (+ and -) counteracting each other.

Some of the uncertainties are centred on zero: others are centred on a positive mid-point. For the latter, there is no cancelling effect and the result of the combination of these uncertainties will be an estimated range for UAG centred on a positive number. The distribution around the mid-point may be skewed toward the positive end. Without evidence ActewAGL is assuming that the distribution is symmetric. The likely range will differ for every gas network and will depend upon the characteristics of the network: its age and history, the market mix and a number of other variables.

Table 9.20 lists the contributors to UAG that are likely to be significant. Some contributors that may also be significant, eg meter damage, were not included.

Table 9.20 Contributors to UAG

Contributing Factor	Midpoint (%)	Uncertainty Range (±%)	Source
Receipt Points	0	0.71	Industry accepted range
Delivery Points	0	0.03	JAM model
Billing cycle issues	0	0.25	JAM estimate
Meter degradation	0.6	0.34	JAM model
Leakage	0.3	0.1	JAM estimate
Unmetered gas for operational purposes	0.05	0.05	JAM estimate
Theft	0.05	0.05	JAM estimate
Combined Estimate	**1.0***	**0.8***	Statistical addition
Range of uncertainty is 0.2 to 1.8 per cent			

Note: Summation of uncertainty ranges was performed by simple sum of midpoints and use of the standard statistical method of adding standard deviations.

The assumptions made in this analysis are conservative, particularly when it comes to leakage, the uncertainty range for which is assumed to be ±0.1 per cent with a mid-point of 0.3 per cent. This range is significantly lower than that assumed in the National Greenhouse and Energy Reporting Scheme Regulation. The regulation uses a methodology that results in estimates of leakage well in excess of this figure.

This analysis indicates that despite the best practices used to manage UAG, UAG within the range of 0.2 to 1.8 per cent is outside ActewAGL Distribution's control. The expenditure required to further reduce the level of UAG below this range would exceed the potential benefit in reduced UAG, leading to an inefficient outcome for the network and retailers and end users.

VENCorp estimates that:

> … because of the distribution of meter capacities and uncertainties the resultant best uncertainty (ie, all meters operating satisfactorily) on the summation of all the meters is ±1.23 per cent (assuming that all the meters are operating within their design range). [108]

VENCorp further states that, on this basis:

> … there is a 95 per cent probability of the injected energy and withdrawn energy of differing by up to ±1.65 per cent (assuming no errors in line pack calculation and no losses from the system). [109]

The conclusion is that UAG figures of up to ±1.65 per cent would not necessarily be indicative of faults in either the injection or withdrawal metering or losses from the system.

[108] VENCorp Un-Accounted-for Gas (UAFG) - Explanatory Notes, p 2
[109] VENCorp Un-Accounted-for Gas (UAFG) - Explanatory Notes, p 2

UAG Benchmarks

In order to verify that the UAG uncertainty range developed in the previous section is in line with that experienced in other Australian and foreign jurisdictions, ActewAGL Distribution has reviewed relevant access arrangements and other evidence based on general research in the public domain. The findings provide useful context for considering the uncertainty range proposed by ActewAGL Distribution. These are provided at attachment O to this access arrangement information.

It is important to keep in mind that while the use of benchmarking and comparisons across gas network companies clearly has a place in the regulatory process, differences among networks may arise due to factors such as geography, the age of the assets, usage patterns, pressures. These differences may have a significant impact on UAG.

Conclusion

There are a number of essential elements in understanding the level of UAG for a particular network that is reflective of efficient and prudent operation. These are:

- the factors that drive UAG;
- the fact that these factors vary depending of the individual characteristics of each network;
- the uncertainty of the measurements used to calculate UAG;
- the uncertainty of the estimates of the various factors that contribute to UAG; and
- the trade-offs of costs and benefits of investing in UAG reduction.

In the case of the ActewAGL network, the key drivers of UAG for older networks such as leakage are not significant and the majority of UAG is driven by factors associated with measurement of gas flowing into and out of the network.

ActewAGL's estimate of a reasonable level for its UAG is up to 1.8 per cent. This may in fact be conservative, because some contributors that would increase this level of UAG have not been included in the estimation of this range, as a result there is very little empirical data on which to make an estimate. It is also assumed that these contributions to UAG will be small.

ActewAGL's actual UAG levels have stayed under the reasonable level. The current level of UAG, while toward the upper end of both the historic and expected ranges, reflects the increasing complexity of the system, comprising two receipts points and an expanding high pressure network. It also reflects that the assets, in particular meters, are now mature. These elements are consistent with the increasing trend of UAG over the last 10 years.

It is also relevant that ActewAGL has had increasing incentives to contain the level of UAG, because of the increasing costs of gas in the wholesale gas market from which it must supply UAG—at its own cost.

Comparison of the Australian and international gas networks shows that ActewAGL's level of UAG is on the low side of the range of UAG that is typical even for a network that has a low incidence of leakage.

In 2004 the ICRC assumed that the historic average level of UAG of 0.7 per cent was representative and set it as the basis of reference tariffs in its 2004 Final Decision. It is now clear that adopting a UAG level of 1.0 per cent would not reflect the reasonable and efficient level of UAG that can be expected of ActewAGL. To continue to do so would be punitive.

ActewAGL Distribution proposes that UAG less than 1.8 per cent be considered efficient and that this be reflected in the access arrangement in relation to the efficient level of UAG. This has been reflected in the tariff variation mechanism in part 4 of the proposed access arrangement.

9.2.3.4 Other costs

Other costs relates to insurance and auditing fees as well as cost of network gas associated with the operation of water bath heaters. As mentioned above, the cost of insurance premiums is allocated throughout the ActewAGL group of businesses on the basis of cost drivers specific to insurance. Insurance costs are allocated on the basis of the appropriate measure for each premium including insured asset value, number of employees and number of directors and executives.

Premium categories are:

- Industrial Special Risk
- Public Liability and Professional Indemnity
- Directors and Officers
- Other.

The costs associated with the water bath heater assume gas consumption of 0.2 per cent of receipts at a cost of $8.75/GJ ($2008/09). The water gas heaters were not metered prior to 2008.

The other direct costs are expected to remain stable and only increase in line with the escalators during the access arrangement period starting in 2010.

A summary of forecast other direct costs during the access arrangement period is provided in Table 9.21.

Table 9.21 Forecast other costs in the access arrangement period

$ million (2009/10)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Other costs	0.22	0.26	0.26	0.26	0.27	0.27	1.33

The other costs will increase by $0.3 million in the access arrangement period starting 2010 versus the prior five years due to the expenditure related to the network gas for the water bath heaters. The other costs are expected to decrease by 24 per cent as insurance premiums have decreased compared to the beginning of the earlier access arrangement period.

9.2.3.5 Self insurance of asymmetric risks

Under the regulatory regime applying to ActewAGL Distribution's gas network business, controls on tariffs during the access arrangement period are set on the basis of expected costs. Typically, these expected cost forecasts are detailed projections of capital and operating expenditure based on anticipated requirements over the access arrangement period and changes expected to external cost drivers (such as demand).

Differences between actual costs and expected costs during the access arrangement period do not result in a revision of the price controls. As such there is a *de-linking* of allowed prices and costs during the regulatory period. This principle is at the heart of the incentives for efficiency provided under the regime. Specifically it provides an incentive for a regulated business to reduce the costs under its control below the level of costs used to set prices.

However, there will always be some aspects of a business's costs which are difficult to project, and which are not under the business's control. There may be additional costs or cost reductions which arise during the access arrangement period as a result of external factors which were not foreseen at the time the expenditure benchmarks were established.

Where there is equal uncertainty as to whether outturn costs will end up higher or lower than projected expenditure, the business faces both an upside and an equal downside risk. However, if it is expected that costs are more likely to increase than they are to decrease as a result of uncertain events, these potential cost variations represent asymmetric risks faced by the business. Such asymmetric risks are not compensated for by the WACC.

There are a number of *risk allocation* mechanisms that can be used to address the asymmetric risk arising from exogenous events. These include:

- Direct inclusion within the expenditure forecasts;
- Direct insurance;
- Self insurance; and
- Cost pass-through.

ActewAGL Distribution uses a combination of all of these mechanisms to manage the asymmetric risks it faces. The merits and tradeoffs associated with each approach vary. Recognising differing characteristics of each approach underlies a holistic approach to risk management. Each is briefly discussed in the following sections to provide a context for ActewAGL Distribution's self insurance expense claim.

In the earlier access arrangement period, no revenue allowance was proposed for self insurance. For risks where direct insurance was impractical or unavailable and where a cost pass-through event was not applied, ActewAGL Distribution effectively bore the risk of an exogenous event occurring. In such a case, ActewAGL Distribution would have borne the full cost of that event without compensation.

In this context, identifying and quantifying the self-insurance risk being borne by the business is important in ensuring that the business is fully compensated for the risks it is bearing.

Including expected costs in the expenditure forecasts

Where an identified asymmetric risk (or number of risks) is realised frequently, it becomes a relatively straightforward matter to incorporate these costs in forecasts so that it becomes an allowance in the regulatory decision. An example would be that, if a certain network asset type was accidently damaged by third parties on average, say, 100 times per annum over a number of years at a fairly stable average cost of repair per incident, then an allowance for this event could reasonably be sought in the regulatory decision for 100 times the average cost per annum.[110]

Allowance of such costs by the regulator effectively means that the business is compensated *ex-ante* for the expected cost of exogenous events. This option results in tariffs being marginally higher than they otherwise would have been if the event actually occurs at a lower rate or at lower average cost and the business were compensated on incurred cost of each event, but lower than if the event occurs at a higher rate or higher cost. In other words, the allowance is made at a particular justified level regardless of the actual cost incurred by the business.

In this case, customers are in effect paying an insurance amount that protects them from higher charges if actual costs are higher, but which they pay regardless of the actual incidence of the event. Thus for endogenous events that are likely to occur relatively frequently within the access arrangement period as part of the business's normal operations, and which are likely to have a minimal overall impact on costs, it is efficient for the business (and the regulator) to group the risks and treat them as part of the normal level of operating costs, rather than to submit a self insurance claim for each event.

By contrast, for more material exogenous events occurring less frequently, it is reasonable for a business to provide specific justification to the regulator regarding the amount being sought to compensate for such an event. In this context, less common and more expensive events will require a specific self insurance allowance, or the adoption of another mechanism such as direct insurance or cost pass-through.

[110] This example abstracts away from the potential for capital expenditure, such as the installation of barriers or markers, at a lower cost to mitigate such a risk.

Direct insurance

In some instances, a prudent business would take out direct insurance to mitigate the cost impact of an event outside of its control. If the exogenous event occurs, then the business's exposure would be limited by this insurance.

Where a business buys direct insurance, the cost of such insurance is included in the business's operating expenditure forecasts.[111] This option therefore results in tariffs being higher than they would otherwise have been because of the approved insurance allowance.

However, if the event insured against should occur, tariffs will not be increased further as a result, and would be lower than if a cost pass-through approach (discussed below) were adopted. Where the distributor takes out direct insurance, there is no impact on the distribution business's net profitability for the regulatory period regardless of whether the exogenous event occurs or not. The business needs to pay for the cost of the external insurance whether or not the event occurs. In the event the risk does materialise the actual costs faced by the distributor are limited by its insurance cover.[112]

In some instances direct insurance may prove to be more cost-effective than self-insurance, and therefore lead to smaller impacts on customer tariffs. This is because the direct insurance provider may be able to take advantage of risk pooling over a larger number of businesses. As a result it may be able to offer lower priced insurance products compared to the distribution business bearing that same risk alone.

However the option of direct insurance may not always be feasible or cost effective. There may be no appropriate external insurance product available (or available at a reasonable cost) for the distribution business to purchase. This is likely to be more common in instances where the exogenous event the distribution business wishes to insure against is uncommon, or the market for insuring against such events is particularly thin.

If a distribution business elects to directly insure against the cost impacts of a particular exogenous event, it is likely to still be required to pay an excess (or deductable) if and when that particular exogenous event occurs. The likelihood of the event occurring and the costs that would then be borne by the distributor are therefore a residual asymmetric risk that the distributor would need to bear. As a result, there is likely to be a self-insurance component associated even with risks that have been directly insured against.

There will also be a trade-off in terms of determining the balance between the level of excess borne by the distributor (and the self insurance requirement that that implies) and the premium paid for the direct insurance. Generally, if the distribution business selects a direct insurance product with a low excess, the premium is likely to be higher than if the excess is set at a higher level.

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[111] The cost of ActewAGL Distribution's direct insurance coverage forms part of operating expenditure for corporate overheads, discussed in chapter 9 of this access arrangement information.

[112] Any 'excess' payment by the distributor under the insurance policy would represent a risk to the business, which is typically covered by self-insurance. This is discussed further below.

Self insurance

An alternative to purchasing direct insurance is for a distribution business to self insure against the cost impact of an exogenous event. Under this approach, the business underwrites the risk of the event occurring, and accepts that it will pay the full cost of the event if it occurs. Self insurance will be practical only in instances where the business has sufficient capacity to credibly be able to bear the risk of incurring this cost, if the event occurs.

Where a business self insures, it is bearing the risk that if the event occurs it will not recover the costs associated with that event, over and above the self-insurance allowance included in the expenditure forecasts. The business therefore needs to be compensated for bearing this risk, which is not covered by the WACC.[113]

The cost of self insurance to the distribution business should therefore be included in the operating expenditure forecasts in the same way as the cost of direct insurance. The cost of self insurance is calculated by multiplying the full cost of the event if it occurred by the probability of the event occurring within the regulatory period (that is, the expected cost of the event).

If the exogenous event does not occur within the access arrangement period, tariffs for that period are effectively higher than they otherwise would have been if the self-insurance amount had not been included in the expenditure forecasts. As discussed above, the impact on tariffs as a result of self-insurance *vis-à-vis* the impact on tariffs from direct insurance will depend on any ability of direct insurers to pool risks between several parties, thereby lowering the costs of the insurance. The distribution business's profits would also be higher under the self insurance approach if the event does not occur, as the self insurance amount is not paid out to a third party but retained by the distribution business. However, this higher profitability is the compensation to the business for bearing the additional risk.

Where the distribution business self-insures and the event *does* occur there would be no additional impact on tariffs, just as in the case of direct insurance. However, since the distribution business has to bear the full cost associated with the event there would be an adverse impact on the distributor's profitability.

Regulated businesses typically adopt a combination of self-insurance and direct insurance to address specific risks. In some instances distributors may elect to purchase direct insurance against some specific loss amount and to self insure beyond that. This would be in circumstances where the distribution business considers itself in a better position to bear the highest level of risk than the market, that is, where the cost of direct insurance products are prohibitive for the highest level of risk. Conversely, a distributor may choose to self insure up to a certain threshold (that is, an excess), and then use insurance purchased on the direct insurance market to pay for losses above the specified self-insurance limit. This reduces the distributor's exposure to the highest level of risk (and therefore protects the

[113] The WACC compensates the business only for systemic or market risk, and not for the asymmetric risk associated with exogenous events beyond the business' control.

financial viability of the business if the event occurs). There will typically be a trade-off between the level of excess (which needs to be self-insured for) and the premiums paid for direct insurance, as discussed in the previous section.

Cost pass-through

A cost pass through mechanism allows for the pass-through of the cost of certain defined events in tariffs during the access arrangement period, if and when such events in fact occur. This is discussed here for the sake of completeness of this discussion on holistic risk management.[114]

Cost pass-through mechanisms allow tariffs to remain lower than they would under any of the other risk mitigation mechanisms if the uncertain event does not in fact occur, since the business is not bearing any risk in relation to these events and therefore does not need to be compensated for either bearing such risk, or taking out direct insurance.

However, in the event the exogenous event occurs, the cost pass-through mechanism will give rise to higher tariffs than those set under self insurance or direct insurance. Under both direct insurance and self insurance, tariffs are not further increased to reflect the actual costs of the event. By contrast, in the event a cost pass-through is triggered tariffs will be adjusted to ensure the distribution business is compensated for the full approved cost of the exogenous event.

Given that the distributor is bearing no risk in relation to the events for which a cost pass-through event is approved, there will be no impact on the business's profitability whether or not the event occurs. The only exception to this would be where there is a materiality provision associated with the operation of the pass-through mechanism that does not allow the full cost of an event to be recovered.

Claim for self insurance expenses

Following on from the discussion above, ActewAGL Distribution has undertaken a process of systematically identifying material asymmetric risks being borne by its gas distribution business and having them quantified by a qualified actuary. The resulting report by Marsh Pty Ltd, *ActewAGL: Self Insurance Risk Quantification* forms confidential attachment C to this access arrangement information.

The forecast annual insurance premium for self insurance in the access arrangement period is $0.53 million per annum or $2.65 million over the access arrangement period, as shown in Table 9.22.

Table 9.22 Forecast self insurance in the access arrangement period

$ million (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Self insurance costs	0.53	0.53	0.53	0.53	0.53	2.65

[114] ActewAGL Distribution is proposing several cost pass through events be approved in the access period under the tariff variation mechanism at Rule 97. These are discussed at section 11.3.2 of this access arrangement information.

The name and description of the event, any relationship of the event to a particular asset or class of assets and reasons for self insuring the event are listed at confidential attachment D to this access arrangement information. In no cases is ActewAGL Distribution able to provide the AER with details of insurance quotes. A decision whether to insure externally or to self insure is made by relevant ActewAGL officers and ActewAGL Distribution's insurance advisors on based on broad experience of the possible events and their likelihood. In the case of deductibles, an explicit trade off is made between the level of deductable and the premium cost.

ActewAGL Distribution has in place a process of continual identification and management of the key risks faced by the business. This comes under the auspices of the Joint Venture Board's Audit and Risk Management Committee. As part of the process, the Board is advised of and endorses the insured and uninsured risk position of ActewAGL. The position is reaffirmed when the Board accepts (or rejects) the terms and conditions of insurance quotations. In relation to the risk assessment undertaken by Marsh, the report has been conveyed to ActewAGL's risk and insurance manager who will report relevant findings known the Audit and Risk Management Committee. The Board has formally noted the set the self insurance quantification by Marsh at its 27 June 2009 meeting as part of its oversight of this gas access arrangement submission.

Treatment of self insurance in the ActewAGL's audited accounts

All self insured activity is expensed and treated as a normal operating cost. There is no compulsion to disclose this activity as a separate event in the ActewAGL financial statements under section 32 of the *ACTEW/AGL Partnership Facilitation Act 2000* (ACT), as it is regarded as a normal operating cost to the business as evidenced by the previously unqualified audit opinions expressed by the joint auditors Deloittes and the ACT Auditor-General's Office.

Self insured activity stems from the decision to exclude certain events which are outside the scope of a normal insurable event. The type of activity not covered by insurance covers things such as minor events that do not exceed the deductible amount, events which cannot be normally insured or events where the benefit of not insuring exceeds the anticipated cost of insuring. Self insured activity is a common occurrence in businesses and decided based on past events and experience by appropriately skilled personnel.

The Australian Accounting Standards Board AASB 137 Provisions, Contingent Liabilities and Contingent Assets (AASB 137) deals with matters in regard to events at 30 June (balance date) requiring disclosure. Events existing at balance date are disclosed as either a "provision" or a "contingency." AASB 137 only allows a provision to be recognised as a liability in the balance sheet amount if there is an obligation. Three tests need to be satisfied before an amount can be recognised. They are that:

- It is probable (that is, greater the 50 per cent chance) that the obligation has occurred;
- The obligation relates to a past event; and
- The obligation can be measured reliably.

If the event does not meet the three tests, then any claim that arises at balance date needs to be disclosed as a note in the accounts as a contingent liability.

A contingent liability is defined in AASB137 as follows:

(a) A possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non occurrence of one or more uncertain future events not wholly within the control of the entity; or

(b) a present obligation that arises from past events but is not recognised because:

   (i) it is not probable that an outflow of resources embodying economic benefits will be required to settle the obligation; or

   (ii) the amount of the obligation cannot be measured with sufficient reliability.

Where self insured events do not meet these parameters at balance date, they will not be disclosed in the accounts.

Should a self insured event approved by the AER occur during the access arrangement period, ActewAGL Distribution would, if required, notify the AER as part of its annual compliance reporting.

9.2.4 Debt raising costs

Many businesses raise debt to partly fund their capital investment programs. In raising debt, a company incurs debt financing costs or transaction costs, which, unlike equity raising costs (which only occur once), occur not only when the debt is initially raised, but also when the debt is rolled over. Such costs are likely to vary between each debt issue. However, the AER assumes a benchmark cost, which varies with size and depends on market conditions.

Consistent with previous regulatory precedent and with the AER's final determination of the WACC parameters, ActewAGL Distribution is assumed to have a gearing of 60 per cent. In the regulatory framework the regulated businesses must be compensated for the legitimate expense of assessed gearing levels.

In the PTRM, which ActewAGL Distribution is using, the debt raising costs are added to the operating expenses. In its Electricity Distribution final determination for the NSW and ACT businesses in April 2009, the AER outlined its preferred methodology for debt raising costs. ActewAGL Distribution has calculated an allowance for benchmark debt raising costs based on the methodology outlined by the AER in its final decision in April 2009.

The AER has assumed that the benchmark median bond issue size is $200 million comprising the debt share (60 per cent) of the capital base. ActewAGL Distribution has matched its debt part of the capital base at the commencement of the access arrangement period starting in 2010 with the corresponding debt raising cost benchmark as shown in Table 9.23.

Table 9.23 Benchmark debt raising costs

	1 issue	2 issues	3 issues	4 issues
Multiples of median Size bond ($m 2009/10)	200	400	600	800
Debt raising costs (basis points)	10.4	9.2	8.7	8.5

ActewAGL Distribution's debt share of the capital base at the commencement of the access arrangement period in 2010 will be $167 million. Consistent with the benchmark cost, ActewAGL Distribution's debt raising cost will be 10.4 basis points per annum.

Table 9.24 Forecast debt raising costs in the access arrangement period

$ million (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15
Debt raising costs	0.17	0.18	0.22	0.27	0.27

Equity raising costs are addressed in chapter 6 of this access arrangement information.

9.3 Summary of forecast of total operating expenditure

ActewAGL Distribution's proposed operating expenditure program continues and builds on the completed program for the earlier access arrangement period. The proposed program is aimed at ensuring ongoing network reliability and compliance as the network expands. Table 9.25 summarises the total proposed operating expenditure program for 2010–15 including debt raising costs, self-insurance and the UNFT.

Table 9.25 Forecast total operating expenditure for the access arrangement period

$ million (2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Controllable costs						
Operating and maintenance	9.59	11.44	11.80	10.60	10.93	54.36
Corporate overheads	3.30	3.41	3.50	3.56	3.59	17.36
Non-system asset charge	0.52	0.52	0.52	0.52	0.52	2.61
Marketing	1.34	1.34	1.36	1.38	1.40	6.82
Other controllable costs	0.23	0.23	0.23	1.02	0.84	2.56
Total controllable costs	**14.98**	**16.95**	**17.42**	**17.08**	**17.28**	**83.71**
Other allowable costs						
Government levies	0.65	0.70	0.70	0.70	0.70	3.46
UNFT	3.41	3.46	3.51	3.56	3.61	17.54
Contestability costs	0.56	0.57	0.59	0.61	0.63	2.95
Unaccounted for gas	1.24	1.24	1.24	1.26	1.28	6.25
Other costs	0.26	0.26	0.26	0.27	0.27	1.33
Total other non-capital costs	**6.13**	**6.23**	**6.31**	**6.39**	**6.49**	**31.54**
Self insurance costs	0.53	0.53	0.53	0.53	0.53	2.65
Debt raising costs	0.17	0.18	0.22	0.27	0.27	1.12
Total operating expenditure	**21.81**	**23.89**	**24.48**	**24.28**	**24.56**	**119.02**

9.4 Outsourced expenditure

The major outsourced expenditure in relation to the ACT, Queanbeyan and Palerang gas distribution network is that for asset management services provided by JAM. Given the significance of this contract, it is discussed in detail in chapter 3 of this access arrangement information. Other outsourced expenditure is listed at attachment S to this access arrangement information.

9.5 Associate contracts

9.5.1 Definition of associate contract

Associate contract means in the NGL:

(a) a contract, arrangement or understanding between a service provider and an associate of the service provider in connection with the provision of an associate pipeline service; or

(b) a contract, arrangement or understanding between a service provider and any person in connection with the provision of an associate pipeline service—

(i) that provides a direct or indirect benefit to an associate; and

(ii) that is not at arm's length. [115]

The same section of the NGL also includes the following definitions:

> *associate* in relation to a person has the same meaning it would have under Division 2 of Part 1.2 of the *Corporations Act 2001* of the Commonwealth if sections 13, 16(2) and 17 did not form part of that Act;
>
> …
>
> *associate pipeline service* means a pipeline service provided by means of a pipeline other than a pipeline to which a 15-year no coverage determination applies
>
> …
>
> *pipeline service* means—
>
> (a) a service provided by means of a pipeline, including—
>
> (i) a haulage service (such as firm haulage, interruptible haulage, spot haulage and backhaul); and
>
> (ii) a service providing for, or facilitating, the interconnection of pipelines; and
>
> (b) a service ancillary to the provision of a service referred to in paragraph (a), but does not include the production, sale or purchase of natural gas or processable gas

Under the *Corporations Act 2001*, referred to in the definition above from the NGL, a reference to *associate* includes (“if the primary person is a body corporate”) a reference to:

(a) a director or secretary of the body; and

(b) a related body corporate; and

(c) a director or secretary of a related body corporate.

A partnership in the ACT qualifies as a *body corporate* under the relevant parts of the Corporations Act (via its eligibility under the Act as a *registrable body*). The term *related* is not a defined term under the Act.

9.5.2 Approved associate contracts

Under section 7.1 of the Gas Code, a service provider could not enter into an Associate Contract without the approval of the relevant regulator. The ICRC was the relevant local regulator in respect of gas distribution pipelines in the ACT. Under the Code, the ICRC could only refuse to approve a proposed associate contract if it considered that the contract would have the effect, or would be likely to have the effect, of substantially lessening, preventing or hindering competition in a market.

Under the NGL, *approved associate contract* means an associate contract approved by the AER under an associate contract decision.[116] The savings and transitional provisions in the NGL deem an associate contract in effect immediately before the commencement of the

[115] NGL, Chapter 1, Part 1, Section 2—*Definitions*
[116] NGL, Chapter 1, Part 1, Section 2—*Definitions*

NGL and approved by a relevant Regulator under section 7 of the Gas Code to be an approved associate contract.[117]

In October 2005, the ICRC approved two associate contracts between ActewAGL Distribution and ActewAGL Retail for the provision of certain services required by the access arrangement to gas suppliers in the ACT.[118] The details in respect of the contracts are provided at attachment P to this access arrangement information.

In March 2004, the ICRC approved an associate contract in the form of a Distribution Services Agreement between ActewAGL Distribution and AGL Wholesale Gas for the provision of gas transportation services to AGL Wholesale Gas as part of interim gas supply arrangements introduced to supplement the supply of natural gas to east coast markets following a January 2004 fire at the Moomba gas plant in South Australia and the resultant constraints on production and supply. This contract had a period of three months and has now expired.[119]

ActewAGL Distribution considers that it has no contracts, arrangements or understandings with any person in connection with the provision of an associate pipeline service that would satisfy the definition in part (b) of the NGL meaning of *associate contract*.

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[117] NGL, Schedule 3, Part 9, Section 48—Approved associate contracts (in effect under NGL, Section 336)
[118] ICRC 2005, Decision, Assessment of Associate Contracts between ActewAGL Distribution and ActewAGL Retail, Report 11 of 2005, October
[119] ICRC 2004, Decision Assessment of Associate Contract between ActewAGL Distribution and AGL Wholesale Gas Limited, March

10 Derivation of total revenue

This chapter of the access arrangement information calculates the total revenue to be derived from the network, including cost of service and the impact of other factors such as incentive mechanisms for efficiency.

Specifically, it addresses the requirement of rule 72(1)(m) for the access arrangement information to include “the total revenue to be derived from pipeline services for each regulatory year of the access arrangement period”.

Total revenue is calculated using the cost building block approach estimated in accordance with Division 3 of Part 9 of the Rules in which the building blocks for each year of the access arrangement period. Rule 75 specifies that:

> Total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:
>
> (a) a return on the projected capital base for the year … ; and
>
> (b) depreciation on the projected capital base for the year … ; and
>
> (c) if applicable – the estimated cost of corporate income tax for the year; and
>
> (d) increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency … ; and
>
> (e) a forecast of operating expenditure for the year ….

Following the presented capital expenditure, capital base projection and operating expenditure described in earlier chapters of this access arrangement information and with the establishment of the tax asset base as described in section 10.4 of this chapter, ActewAGL Distribution’s gas network total revenue requirement for the access arrangement period starting in 2010 will be $370.6 million (nominal). The distribution of the revenues is presented in Table 10.1 below. The mechanism of estimating the revenue requirement is available in the PTRM at attachment 0 to this access arrangement information.

Table 10.1 Revenue requirement for ActewAGL Distribution’s ACT, Queanbeyan and Palerang gas network 2010/11 to 2014/15

Nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Return on capital	30.87	33.38	41.72	52.89	53.67
Depreciation	3.65	4.74	4.90	4.76	5.08
Operating and maintenance	22.26	24.90	26.05	26.37	27.24
Corporate income tax	1.20	1.36	1.63	1.97	2.00
Incentive mechanism payments (decrements)	na	na	na	na	na
Total	**57.98**	**64.38**	**74.29**	**85.99**	**87.99**

na – not applicable

10.1 Depreciation

ActewAGL Distribution's depreciation schedule for the regulatory period is outlined in chapter 7 of this access arrangement information discussing the capital base. ActewAGL Distribution has applied the Rules 88-90 in determining the depreciation allowance as outlined in section 7.2.3 of this access arrangement information. Details of the calculation can also be found in ActewAGL Distribution's PTRM at attachment 0 to this access arrangement information.

Consistent with the earlier access arrangement, ActewAGL Distribution has applied a straight-line approach to depreciation. This ensures that assets are only depreciated once.

ActewAGL Distribution's forecast depreciation has been calculated using the AER's post-tax revenue model and set out in Table 10.2.

Table 10.2 Economic depreciation 2010/11 to 2014/15

$000 nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Straight line depreciation	9.5	11.0	12.8	14.7	15.2
Inflation adjustment	-5.8	-6.3	-7.9	-10.0	-10.1
Economic depreciation	3.6	4.7	4.9	4.8	5.1

As discussed in chapter 7 of this access arrangement information, ActewAGL Distribution proposes to adopt a depreciation schedule that has been calculated using forecast capital expenditure for rolling forward the capital base from 1 July 2010 to 30 June 2015. This is consistent with the Rule 90.

10.2 Return on capital

The movements in the value of the capital base over the 2010/11 to 2014/15 access arrangement period are set out in Table 10.3.

Table 10.3 Roll forward of the capital base 2010/11 to 2014/15

$ million ($2009/10)	2010/11	2011/12	2012/13	2013/14	2014/15
Opening capital base	278.3	294.8	360.9	448.1	445.4
Net capital expenditure	25.8	76.7	99.2	10.8	11.4
Depreciation	9.3	10.6	12.0	13.6	13.7
Closing capital base	294.8	360.9	448.1	445.4	443.1

ActewAGL Distribution has rolled forward the capital base in the PTRM as described in chapter 7 of this access arrangement information.

The return on capital building block is reproduced in Table 10.4.

Table 10.4 Roll forward of the capital base 2010/11 to 2014/15

$ million (nominal)	2010/11	2011/12	2012/13	2013/14	2014/15
Return on equity	14.0	15.2	19.0	24.1	24.4
Return on debt	16.8	18.2	22.7	28.8	29.2
Return on capital	30.9	33.4	41.7	52.9	53.7

10.3 Operating expenditure

The calculation of operating and maintenance costs is detailed in chapter 9 of this access arrangement information. ActewAGL Distribution's operating expenditure forecasts for the 2010/11 to 2014/15 access arrangement period are shown in Table 10.5 .

Table 10.5 Operating expenditure 2010/11 to 2014/15

$ million (nominal)	2010/11	2011/12	2012/13	2013/14	2014/15
Operating expenditure	22.3	24.9	26.0	26.4	27.2

10.4 Corporate income tax

This section of the access arrangement information 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's total revenue requirement. ActewAGL Distribution is proposing that the access arrangement period should be modelled using a post-tax framework. This requires ActewAGL Distribution to establish a tax asset base (TAB) consistent with Rule 76(c).

10.4.1 Estimation of a tax asset base

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; and
- γ (the assumed utilisation of imputation credits) is deemed to be 0.65.

The estimate must take into account the depreciation of the TAB for tax purposes. Under the pre-tax approach previously approved by the ICRC and applying to ActewAGL Distribution in the earlier access arrangement period, the allowance for tax was embedded within the return on equity calculation. Thus there was no need to calculate a depreciation allowance and, accordingly, no need for a TAB. Under the proposed transition to a post-tax revenue model, ActewAGL distribution must establish a TAB.

ActewAGL Distribution notes that the NGR do not specify how the TAB should be estimated. However in June 2007, the AER released an issues paper titled *Transition of energy businesses from pre-tax to post-tax regulation,* which proposes an approach by which the TAB could be established for the transition to post-tax regulation. ActewAGL Distribution further notes the AER's statement in the issues paper that "there may be a degree of judgment required in establishing the initial tax base". [120] The AER's approach to setting the TAB requires an assessment of:

- the date ActewAGL Distribution was first subject to tax or the National Tax Equivalent Regime (NTER)
- the tax value of assets at that date, in sufficient details to distinguish capital base assets from non-capital base assets
- the vintage, or age, profile of the capital base assets when first subject to the NTER.

As per the issues paper, the AER's proposed approach is to roll forward the tax value of the asset base from "the date the business was first subject to tax (or the NTER)". In its final electricity decision on 28 April 2009, the AER decided to roll forward ActewAGL Distribution's TAB from the date that ACTEW Corporation was first subject to the NTER.

ACTEW Corporation and its subsidiary entities were first recorded on the NTER Entity Register on 1 July 2001. ACTEW Corporation Limited and its current subsidiary entities continue to be part of the NTER and are recorded in the current NTER Entity Register maintained by the NTER Administrator.

Consistent with the final electricity decision of 28 April 2009, ActewAGL Distribution has set its original TAB for gas to 1 July 2001. The value of assets installed prior to this date have been back calculated using straight-line depreciation the rate and installation dates from ActewAGL Distribution's as per the account books on the assumption that the installation costs and dates are consistent between account and tax books.

ActewAGL Distribution proposes to use standard tax lives for gas supply assets per the Tax Commissioner's ruling *TR 2000/18C4 Income tax: depreciation effective life.* Whilst this ruling was not in place at 1 July 2001, the then current ruling did not specify gas supply

[120] Appendix A to 'Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014', November 2007, p 63

assets' effective lives. The Tax Commissioner has stated that, where an asset life has not been specified, the asset owner must determine the asset's effective life. Therefore, for the purposes of the TAB RFM, ActewAGL proposes to use the Commissioner for Taxation's first available (and subsequently unchanged) specification of gas supply asset effective lives, TR 2000/18C4. Table 10.6 shows the resulting standard tax lives for ActewAGL's adopted asset classes.

Table 10.6 Adopted standard tax lives of assets

Asset class	Standard life (years)
TRS & DRS - Valves & Regulators	40.0
HP Mains	50.0
MP Mains	50.0
Meters - Tariff	15.0
Meters - Contract	15.0
MP Services	30.0
HP Services	30.0
IT Systems	5.0
Regulatory Costs	5.0

10.4.2 Tax Asset Base Roll Forward 2001-2010

ActewAGL Distribution's TAB was $168.6 million as at 1 July 2001. The value of these assets includes assets in the divisional tax asset register for gas distribution. Table 10.7 provides a breakdown of opening tax asset values for each category of assets in the TAB.

Table 10.7 Opening tax value and remaining lives in 2001/02

Asset class	Value $ million (nominal)	Remaining life 2001/02 (years)
TRS & DRS - Valves & Regulators	1.68	27.1
HP Mains	29.87	38.3
MP Mains	119.60	37.4
Tariff meters	7.14	9.4
Contract meters	1.02	9.4
MP Services	9.08	25.3
HP Services	0.18	44.4
IT Systems	-	-
Regulatory Costs	-	-

ActewAGL Distribution 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 base in chapter 7 of this access arrangement information. 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 tax asset base. Depreciation has been calculated on a straight-line basis consistent with the determined methodology for ActewAGL Distribution Electricity Network's tax asset base. ActewAGL Distribution notes that its actual tax asset base is depreciated using a diminishing value approach. The diminishing value method results in significantly higher depreciation rates for relatively new assets. Major assets in ActewAGL's tax asset base are relatively new with the result that the depreciation allowance on a straight-line basis is lower than that under diminishing value. This implies that the opening TAB value for the access arrangement period is higher (and ActewAGL Distribution's tax allowance lower) than it would have been had a diminishing value depreciation methodology been applied.

ActewAGL Distribution submits a TAB value of $197.08 million (nominal) for the start of the 2010-15 regulatory period as demonstrated in Table 10.8.

Table 10.8 Roll forward of the TAB from 2001/02 to 2009/10

Asset class	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	F2008/09	F2009/10
Opening TAB	168.58	174.09	177.74	179.41	182.85	183.26	187.31	188.56	189.55
Capital expenditure	10.91	9.33	7.59	9.84	7.28	11.23	8.75	8.86	15.63
Straight-line depreciation	-5.40	-5.67	-5.93	-6.40	-6.87	-7.18	-7.50	-7.87	-8.09
Closing TAB	174.09	177.74	179.41	182.85	183.26	187.31	188.56	189.55	197.08
Opening TAB at 1 July 2010									197.08

10.4.3 Tax Asset Base Roll Forward 2010 to 2015

Consistent with the roll forward of ActewAGL Distribution's capital base from 1 July 2010 to 30 June 2015 in chapter 7 of this access arrangement information, ActewAGL Distribution proposes to adopt tax asset base roll forward schedule that has been calculated using forecast capital expenditure. Similarly, ActewAGL Distribution 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 10.9 Roll forward of the TAB from 2010/11 to 2005/15

$ million nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Opening TAB	197.08	214.87	283.18	374.37	373.60
Forecast capital expenditure	25.30	76.66	101.28	11.33	12.23
Straight-line depreciation	7.51	8.35	10.09	12.10	12.54
Closing TAB	214.87	283.18	374.37	373.60	373.29

10.4.4 Tax depreciation concessions 2010-2015

ActewAGL Distribution has calculated the tax depreciation concessions available to the business in the 2010–15 access arrangement period. These can be found in Table 10.10.

Table 10.10 Tax depreciation concessions 2010/11 to 2014/15

$ million (nominal)	2010/11	2011/12	2012/13	2013/14	2014/15
Tax Depreciation Concessions	1.20	1.36	1.63	1.97	2.00

10.4.5 Corporate income tax building block

Consistent with rule 76 (c), ActewAGL Distribution proposes a corporate income tax building block as set out in Table 10.11.

Table 10.11 Corporate income tax building block 2010/11 to 2014/15

$ million (nominal)	2010/11	2011/12	2012/13	2013/14	2014/15
Tax Payable	3.4	3.9	4.6	5.6	5.7
Value of Imputation Credits	-2.2	-2.5	-3.0	-3.7	-3.7
Tax Allowance	1.20	1.36	1.63	1.97	2.00

10.5 Revenue requirement and X factors

In accordance with Rule 72, ActewAGL Distribution's proposed total revenue requirement and the annual revenue requirement for each year of the period have been calculated using the PTRM. A populated Post Tax Revenue Model is provided at attachment 0 to this access arrangement information.

The methodology used to determine reference tariffs for the access arrangement period is that used in earlier access arrangements.

Calculating reference tariffs involves the following steps:

1) Calculate the total revenue requirement using the cost of services building block approach as described in this chapter of the access arrangement information;

2) Allocate the total revenue requirement to the contract and tariff markets (see section 11.2 of this access arrangement information);

3) Determine the revenue requirement and price paths for the contract and tariff markets; and (see section 11.2.2.2 of this access arrangement information);

4) Calculate the reference tariffs for each service to deliver the required revenue paths.

The reference tariff and its calculation are shown in Table 10.12.

Table 10.12 Calculation of revenue allowance the reference tariff

Nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Regulatory depreciation	3.65	4.74	4.90	4.76	5.08
Return on capital	30.87	33.38	41.72	52.89	53.67
Tax allowance	1.20	1.36	1.63	1.97	2.00
Operating expenditure	22.26	24.90	26.05	26.37	27.24
Incentive mechanism payments (decrements)	na	na	na	na	na
Unsmoothed revenue requirement	**57.98**	**64.38**	**74.29**	**85.99**	**87.99**
Energy forecasts (TJ)	6,545	6,525	6,565	6,642	6,736
Revenue yield (tariff /TJ)	8,035	9,205	10,545	12,080	13,838
Smoothed revenue requirement	**55.35**	**63.13**	**72.78**	**84.33**	**97.42**
of which tariff revenue	*52.59*	*60.06*	*69.23*	*80.23*	*93.22*
of which contract revenue	*2.77*	*3.07*	*3.55*	*4.10*	*4.20*
X factor tariff revenue (%)*	12.21	12.21	12.21	12.21	12.21

na – not applicable
*The X-factors in the table above are indicative only. The proposed price path is shown in chapter 11 and in the access arrangement.

The allocation of revenues to tariff and contract services is provided in chapter 11 of this access arrangement information.

10.6 Incentive mechanisms

10.6.1 Previous period increments or decrements

Transitional Provision 5(1)(a) in Schedule 1 to the NGR requires the AER, in deciding whether to approve an access arrangement revision proposal for a transitional access arrangement, to take into account the operation of any incentive mechanism approved under clause 8.44 of the former Gas Code. An *incentive mechanism* under clause 8.44 clause permits a service provider to retain benefits of lower costs or greater sales than expected for the duration of the access arrangement period or for a longer period approved by the regulator.

ActewAGL's current access arrangement includes the following incentive mechanism provision:

> The incentive mechanism used in calculating the Reference Tariffs is that Reference Tariffs apply each year regardless of whether the forecasts on which the Reference Tariffs were determined are realised. [121]

As recognised by the AER,[122] the use of forecast demand (with no subsequent adjustment for actuals) encourages a service provider to develop the market and increase demand, as it benefits from retaining the additional revenue for the remainder of the access arrangement period.

Rule 72(1)(i) requires access arrangement information to include:

> … if an incentive mechanism operated for the previous access arrangement period—the proposed carry-over of increments for efficiency gains or decrements for efficiency losses in the previous access arrangement period and a demonstration of how allowance is to be made for any such increments or decrements.

Under the incentive mechanism applying in the earlier access arrangement there are no revenue increments or decrements that are formally carried over to the subsequent access arrangement period.

10.6.2 Proposed incentive mechanism for the 2010-2014 period

10.6.2.1 Rule requirements

Under Rule 98, the access arrangement may include (and the AER may require it to include) one or more incentive mechanisms, consistent with the revenue and pricing principles in the NGL, to encourage efficiency in the provision of services. The NGR does not specify the form or coverage of any incentive mechanisms, although Rule 98(2) clarifies that the mechanism could involve carrying over increments or decrements from one regulatory period to the next, that is, a *rolling carryover* mechanism.

10.6.2.2 Rationale

Rule 72(1)(l) requires the access arrangement information to include "the service provider's rationale for any proposed incentive mechanism" to operate in the new access arrangement period.

ActewAGL Distribution proposes to retain the current incentive mechanism relating to the use of forecast demand in the access arrangement period. As noted above, this mechanism provides an incentive to develop the market and increase demand during the period. As a consequence it is consistent with the revenue and pricing principles in the NGL and, in particular, the provision of effective incentives to promote the efficient use of the pipeline.[123]

[121] Clause 4.5 Incentive mechanism in Part 4 Reference tariff policy
[122] AER, Access Arrangement Guidelines, March 2009, p. 63
[123] NGL, 24(3)(c)

ActewAGL Distribution also proposes to introduce an additional rolling carryover incentive mechanism for the access arrangement period. The rolling carryover mechanism is set out in clause 4.6 of ActewAGL Distribution's access arrangement.

The introduction of a rolling carryover mechanism brings the incentive arrangements applying to ActewAGL Distribution's gas network business into line with those applying to gas distribution businesses in other jurisdictions, and to ActewAGL Distribution's electricity network business. The gas distribution businesses in Victoria and South Australia both have rolling carryover in their access arrangements that apply in relation to both operating and capital expenditure. ActewAGL Distribution's electricity network is subject to a rolling carryover mechanism under the AER's efficiency benefit sharing scheme (EBSS) for operating and maintenance expenditure.

The adoption of a rolling carryover form of incentive mechanism would enhance the incentives for efficiency already present under the fixed term access arrangement period. This is because this form of mechanism ensures that efficiency gains achieved compared to expenditure benchmarks determined for the access arrangement period would be retained by the business for a full five years, regardless of the when in the period the gain was made. Conversely, the penalty associated with any efficiency losses would be borne by the business for a full five years. As a result ActewAGL Distribution will receive the same reward (penalty) for an efficiency gain irrespective of the year in which that particular gain (loss) was made. As noted above, Rule 98(2) makes explicit provision for an incentive mechanism to involve carrying over increments or decrements from one regulatory period to the next.

As a result, ActewAGL Distribution considers the proposed mechanism to be consistent with the revenue and pricing principles set out in the NGL, and specifically the requirement that the service provider is provided with effective incentives to promote economic efficiency with respect to investment in the pipeline and provision of reference services.[124] Users will benefit from the lower costs of future service provision, which will be reflected in future cost projections and therefore tariffs. In the absence of a rolling carryover mechanism, the share of efficiency gains and losses received by ActewAGL Distribution would decline as the access arrangement period progresses, which would reduce incentives to improve efficiency towards the end of the period.

In addition to providing a constant incentive to make efficiency gains throughout the access arrangement period, the rolling carryover mechanism also provides distributors with an incentive to reveal actual efficient costs, which can then be used as a basis for establishing future expenditure forecasts. This feature was recognised by the AER in its development of the EBSS for electricity distribution.[125]

Rule 71 allows the AER to infer from the presence of an incentive mechanism that capital and operating expenditure are efficient, without embarking on a detailed investigation. As a result, through the adoption of a rolling carryover mechanism in this access arrangement period, ActewAGL Distribution expects that the AER will be able to adopt a more

[124] NGL, 24(3)(a) and (b)
[125] AER, *Electricity Distribution Service Providers, Efficiency Benefit Sharing Scheme*, June 2008, p. 1

lighthanded approach in assessing actual outturn capital and operating expenditure at the time of the next access arrangement revision.

10.6.2.3 Features of the proposed incentive mechanism

This section discusses the key features in relation to the rolling carryover mechanism ActewAGL Distribution has proposed in its access arrangement. Specifically:

- the mechanism is proposed to apply to both capital and operating expenditure;
- adjustments are proposed to be made at the end of the regulatory period, prior to calculating the carryover amount, to reflect differences between projected and outturn customer numbers and any changes in the scope of services; and
- any *negative* efficiency amount at the end of the regulatory period would be taken into account by the AER in determining the allowed revenue for the following access arrangement period.

Application to capital and operating expenditure

ActewAGL proposes that the rolling carryover mechanism should apply to both capital and operating expenditure. By treating the savings made in relation to either capital or operating expenditure in the same way, the mechanism ensures equal incentives to pursue savings in both operating expenditure and capital expenditure. As a result there is no imbalance in the incentives applying to different types of expenditure which might lead to the inefficient substitution of one form of expenditure for another.

The issue of whether rolling carryover mechanisms should apply to capital as well as operating expenditure is one that has been considered by several regulators. The Victorian ESC was the first of the jurisdictional regulators to introduce a rolling carryover mechanism, in 2000. The mechanism initially applied to both operating expenditure and capital expenditure for electricity distribution.[126] However, in its subsequent electricity distribution price review, the ESC was concerned that the mechanism could be providing incentives for distribution businesses to inefficiently reduce capital expenditure. Accordingly, in the subsequent decision the ESC removed the efficiency carryover mechanism from capital expenditure whilst retaining it for operating expenditure.[127]

The AER's EBSS for electricity distribution also applies the carryover mechanism to operating expenditure only. The AER decided not to develop an EBSS for capital expenditure considering that, while it was desirable in principle to provide DNSPs with a continuous incentive to make capital expenditure efficiency gains in order to provide balanced incentives to encourage efficiencies across both forms of expenditure, applying the EBSS to capital expenditure may provide inappropriate incentives to defer capital expenditure to a following regulatory control period.[128]

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[126] Office of the Regulator-General, Victoria, *Electricity Distribution Price Determination 20001-2005*, September 2000.
[127] ESC, *Final Decision for the 2006-2010 Electricity Distribution Price Review, Final Decision,* October 2005, Chapter 10
[128] AER, *Efficiency Benefit Sharing Scheme - Final Decision*, June 2008, p. 6

In the specific case of gas distribution, the ESC concluded in its 2008-2012 Victorian Gas Access Arrangement Review[129] that it was appropriate to continue to apply a rolling carryover mechanism to both operating expenditure and capital expenditure for gas distribution businesses on the basis that:

- the widespread capital expenditure deferrals observed in the electricity industry did not appear to have occurred in the gas industry;
- the nature of capital expenditure in the gas industry is such that the regulator is better able than in the electricity industry to monitor units and unit rates, providing it with the ability to adjust benchmarks to reflect the actual amount of capital works undertaken; and
- removing capital expenditure from the rolling carryover mechanism may create an imbalance in the regime's incentives.

Accordingly, the rolling carryover mechanism continues to apply to both capital expenditure and operating expenditure for gas distribution businesses in Victoria. It also applies to both capital expenditure and operating expenditure for the gas distribution business in South Australia. ActewAGL considers that such an approach is appropriate so as to provide balanced incentives to encourage efficiencies across both forms of expenditure.

Adjustments prior to calculating the rolling carryover amount

Under ActewAGL Distribution's incentive mechanism proposal, the appropriate carryover amount would be calculated at the end of the access arrangement period, and added to the revenue requirement for the following access arrangement period.

ActewAGL considers that there is a small number of circumstances when it would be appropriate to adjust the original expenditure benchmarks against which efficiency is being assessed, before calculating the incentive carryover amount. Such adjustments would reflect changes in circumstances (and therefore costs) outside of the business's control, and which do not therefore represent *true* efficiency gains (or losses). Such adjustments are necessary to ensure that the business is provided with a reasonable opportunity to recover at least the efficient costs incurred in providing reference services[130] and are a common feature of the rolling carryover mechanisms applied to other gas distribution businesses, and of the AER's EBSS for electricity distribution.[131]

The grounds on which ActewAGL could seek an adjustment to the original benchmarks in calculating the rolling carryover amount at the end of the regulatory period are set out in the revised access arrangement, and are as follows:

- a change in the scope of the activities which form the basis of the determination of the original benchmarks; and/or

[129] ESC, *Gas Access Arrangement Review Final Decision 2008-2012*, March 2008.
[130] NGR, Revenue and Pricing Principles, 24(2)
[131] The EBSS allows for an adjustment for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period, and changes in responsibilities that result from compliance with a new or amended law or licence or other statutory or regulatory requirement.

- a difference between forecast and actual connections; and/or
- any increase or decrease in actual operating and/or capital expenditure as a result of approved cost pass through events.

ActewAGL notes that these proposed adjustments to the original benchmarks are consistent with those approved for MultiNet, SPAusNet and Envestra in Victoria.

Where there is a change in the scope of services compared to those envisaged at the time at which the expenditure benchmarks were approved arising from exogenous factors and imposing material additional costs on ActewAGL Distribution, ActewAGL would provide the AER with details of the costs incurred and the proposed adjustment to the expenditure benchmarks at the time of the next access arrangement revision.

In relation to the process for seeking an adjustment to the benchmarks for the difference between forecast and actual connections, ActewAGL proposes that the adjustment amount be determined as follows:

Adjustment amount = $(A - F).R_U$

Where A is actual units completed
F is forecast units completed
R_U is the approved unit rate

Specifically, at the time of the next access arrangement revision, and prior to calculating the incentive amount under the rolling carryover mechanism:

- the operating expenditure benchmarks will be adjusted by $32 (2009/10) per connection, where the number of connections differs from those set out in Table 10.13. This cost per connection is consistent with that determined in section 9.2.1.3 of this access arrangement information:
- the capital expenditure benchmarks will be adjusted by $1,956 (2009/10) per connection, where the number of connections differ from those set out in Table 10.13. This capital cost per connection has been estimated based on the total market expansion capital expenditure less the expenditure in 2010/11 for the Hume data centre which is a special case. The adjusted market expansion capital expenditure was then divided by the expected number of new connections during the access arrangement period.

Table 10.13 Projected number of connections

	2010	2011	2012	2013	2014	2015
Tariff	116,083	119,711	123,429	127,030	130,284	133,420
Contract	41	41	41	41	41	42

The basis for the assumed number of connections is set out in section 5.2.5 of this access arrangement information.

Approved increases or decreases in actual operating and/or capital expenditure as a result of approved cost pass through events would also be excluded in calculating the carryover amount.

The AER’s EBSS determined in the final decisions for the NSW and ACT electricity distribution businesses allows for a number of nominated costs to be excluded DNPS to nominate at the start of the regulatory period uncontrollable expenditure that would be excluded from the EBSS. Expenditure categories that ActewAGL Distribution proposes to exclude from operation of the EBSS are specified in the access arrangement.

Treatment of negative efficiency amounts

The rolling carryover mechanism proposed by ActewAGL Distribution is symmetrical and applies to any increase in costs as well as decreases in costs.

In the event that there is an overall negative carryover amount at the end of the regulatory period, ActewAGL Distribution proposes that the treatment of this negative amount (that is, whether it will be carried over to the next period) be determined by the AER at the time of the next access arrangement revision having regard to the circumstances in which the negative carryover amount has arisen. ActewAGL Distribution considers that this approach provides a suitable balance between retaining the incentive benefits of a symmetric scheme, and having regard to the legitimate interests of the business and the requirement of 24(2) of the NGL.

11 Services, cost allocation and pricing

This chapter of the access arrangement information specifies the services offered and explains the basis and derivation of tariffs, including cost allocation, customer classes and tariff variation mechanisms.

11.1 Services offered

The NGR and the AER's RIN require the access arrangement to describe the pipeline services to be provided and to specify the reference services.[132] A reference service is defined in Rule 101 as "a pipeline service that is likely to be sought by a significant part of the market".

ActewAGL Distribution proposes to offer eight pipeline services, comprising six reference services and two non-reference services. These services are the same as those offered in the earlier access arrangement.

The six reference services, as set out in part 2 of the access arrangement proposal, are as follows:

Capacity Reservation Service—a transport service from the receipt point to a single non-tariff delivery point. Charges are determined on the basis of capacity reserved. Additional capacity reservation options for this service are:

- **Summer Tranche Option**—provides an option to book capacity between the months of October and April (inclusive);
- **Short Term Capacity Option**—available to end use customers using gas for purposes other than space heating (subject to available capacity). There are two options—one for 30 TJ or less of gas per year, the other for over 30 TJ of gas per year. A short term capacity charge (premium) may be charged for the under 30 TJ option;

Managed Capacity Service—a transport service from receipt point to a single non-tariff delivery point. Charges are determined on the basis of capacity reserved;

Throughput Service—a transport service from the receipt point to a single non-tariff delivery point. Charges are determined on the basis of throughput;

Multiple Delivery Point Service—a transport service from the receipt point to a number of non-tariff delivery points. Charges are based on the relevant service at each delivery point;

Tariff Service—a transport service from the receipt point to one or more tariff delivery points. Charges are determined on the basis of throughput;

[132] Rule 48(1)

Meter Data Service—a service comprising the reading of meters and handling of metering data.

The two non-reference services offered by ActewAGL Distribution are:

Interconnection of Embedded Network Service—a service to provide for the establishment of a single delivery point from the network to an embedded network; and,

Negotiated Service—any service negotiated to meet the needs of a user which is not met by the reference services.

ActewAGL Distribution's proposed reference services are those pipeline services which are likely to be sought by a significant part of the market. The non-reference services have not been sought by any customers or potential customers during the earlier access arrangement period, and ActewAGL Distribution considers that they are unlikely to be sought by a significant part of the market during the access arrangement period. The proposed reference and non-reference services therefore remain appropriate.

11.1.1 Allocating costs between services

The NGR set out requirements for allocating costs between reference services and other pipeline services.[133] The portion of total revenue allocated to reference services is determined by the ratio in which costs are allocated between reference and other services (Rule 93(1)). Rule 93(2) requires allocation of directly attributable costs to reference and other services as appropriate, and other costs (such as overheads) to be allocated (consistent with revenue and pricing principles) between these services on a basis determined or approved by the AER.

As outlined above, ActewAGL Distribution offers six reference services and two non-reference services. While the non-reference services continue to be offered, they are not currently used by any customers and therefore ActewAGL Distribution incurs no costs in relation to them. Further, the cost of maintaining the availability of non-reference services is negligible. Accordingly, ActewAGL Distribution's costs are fully allocated to reference services.[134]

Costs are allocated between customer classes in order to set the tariffs for each reference service, as described in the following sections.

11.2 Tariffs for reference services

11.2.1 Tariff classes

The NGR specify that, for the purpose of determining reference tariffs, customers must be divided into tariff classes. Tariff classes must be constituted with regard to grouping of

[133] Rule 93

[134] The AER may permit the allocation of costs of rebateable services to reference services. However, ActewAGL Distribution proposes no rebateable services.

customers together on an economically efficient basis and the need to avoid unnecessary transaction costs.[135]

ActewAGL Distribution's customers are grouped into two classes:

- Tariff customers; and
- Contract customers.

This grouping is appropriate and economically efficient, as required by the NGR. The split is based on the nature and size of the connection and load. Within each group customers have broadly similar load and connection characteristics. The tariffs available for each group reflect the different economic costs of supplying each group. Transactions costs, particularly the costs of metering, are also taken into account in determining the appropriate tariffs to be offered to each group, as discussed further in section 0 below.

Contract customers are those that consume more than 10 TJ of gas per annum. These customers have different load and connection characteristics to the tariff customers, often requiring multiple connection points, and are generally more responsive to price signals regarding capacity. The relatively large loads consumed by the customers in this group mean that the transactions costs associated with installing more sophisticated metering, to measure maximum daily and hourly consumption, are warranted.

The reference services for the contract customer class comprise:

- Capacity reservation services;
- Managed capacity services;
- Throughput services;
- Multiple delivery point services; and
- Meter data services.

While the contract customers face several service options, the existing contract customers all take the capacity reservation service with meter data services. Within the meter data services, most contract customers take the communications option that allows meters to be read remotely. However, one customer with 97 meters finds it more efficient to have its meters manually read monthly.

The tariff customer class comprises residential and business customers consuming fewer than 10 TJ per annum. The reference services for tariff customers are:

- Tariff services; and,
- Meter data services.

The tariff for the tariff service involves a fixed charge and a throughput charge consistent with an efficient two part tariff structure. More complex tariffs, involving capacity charges as for the contract market services, would require more costly metering capability.

[135] Rule 94

11.2.2 Revenue and cost allocation

The NGR require the access arrangement information to include the proposed approach to the setting of reference tariffs including the method used to allocate costs.[136]

ActewAGL Distribution has allocated the total cost of providing reference services between contract and tariff markets using the methodology approved by the ICRC in the earlier access arrangement period and applied since the 2001 access arrangement decision. The methodology uses a series of rules to allocate operating and capital costs to contract and tariff market segments in line with their respective use of network services. It is consistent with the requirements for allocating costs between reference and other services, as set out in Rule 93. Costs that are directly attributable to either market segment (contract or tariff) are allocated to that segment, while other costs which are shared between segments, are allocated on the basis of reasonable cost drivers. The cost allocation model is included as attachment R to this access arrangement information and is described below.

11.2.2.1 Allocation of operating costs

Operating costs are allocated between tariff and contract customers using an activity based costing methodology. ActewAGL Distribution has identified ten operating cost categories which account for approximately 99.1 per cent of total operating expenditure, to allocate costs to contract and tariff cost pools. The remaining 0.9 percent of the operating expenditure has been allocated in accordance with the average percentage derived from the ten operating cost categories. Costs for each activity are based on expenditure levels in the 2009/10 base year. Where a cost category is only driven by one market (tariff or contract), all costs have been allocated directly to that market segment. However, where costs are shared, an allocation 'key' provides the rule for attributing costs to either contract or tariff markets. The keys used to allocate costs to operating expenditure categories are the same as those approved in the 2004 Final Decision, with the exception of the UNFT which is added to government levies. The operating cost categories and the allocation keys are provided in Table 11.1.

[136] Rule 72

Table 11.1 Allocation keys used to allocate operating cost categories

Opex category	Allocation key
Asset Services costs	Where the costs have not been allocated directly to tariff and contract customers, they are allocated based on the allocation determined in the earlier access arrangement using relative size of MDQs (actual peak data from 2007/08), customer numbers, new connections and the actual revenue split in 2007/08.
Asset Management costs	Costs allocated by relative size of MDQs.
Corporate overheads	The actual revenue split in 2007/08 has been used as a proxy to distribute corporate overhead costs.
Non System Asset Charge	Costs allocated by relative size of MDQs.
Marketing	Costs allocated entirely to the tariff market.
Other direct costs	Costs allocated by relative size of MDQs.
Government levies & UNFT	The actual revenue split in 2007/08 has been used as a proxy to allocated government levies.
Contestability Charge	Costs allocated entirely to the tariff market.
UAG Other Opex	The actual revenue split in 2007/08 has been used as a proxy to distribute UAG and Other Opex.

11.2.2.2 Allocation of capital costs

Capital costs are split in proportion to the market segments' relative shares of the capital base. The methodology requires the regulated asset base (as at 1 July 2010 from the RFM) and capital expenditure over the access arrangement period to first be allocated to asset classes and second, split into contract and tariff markets. Two asset classes—contract meters and tariff meters—have been allocated directly to the relevant market segments. The other asset classes have been allocated via the relative size of contract and tariff MDQs. The capital costs for medium pressure mains—utilised almost entirely by the tariff market—have been allocated using the same allocator as in the earlier access arrangement period. The allocation of the rolled forward capital base is shown in Table 11.2.

Table 11.2 Allocation of the average values of the capital base 2010/11 to 2014/15

$million	Total	Contract	Tariff
HP Mains	174.15	15.59	158.56
HP Services	0.78	0.07	0.71
MP Mains	146.65	0.10	146.55
MP Services	61.39	0.04	61.34
TRS & DRS – Valves & Regulators	22.82	2.04	20.77
Contract meters	1.44	1.44	-
Tariff meters	16.88	-	16.88
Regulatory Costs	0.34	0.03	0.31
IT System	0.79	0.07	0.72
Total	**425.24**	**19.38**	**405.85**

Table 11.3 shows the allocation of operating and capital costs to the contract and tariff markets.

Table 11.3 Allocation of operating and capital costs

$ million nominal	Total	Contract	Tariff
Operating costs	142.32	7.28	135.04
Capital costs	228.32	10.41	217.91
Total allocation	370.64	17.69	352.95

11.2.2.3 Revenue allocation

For each year of the access arrangement period, ActewAGL Distribution has determined the costs allocated to each of the contract and tariff markets based on the operating expenditure and capital base splits described above. The proportion of total costs allocated to each of these classes over the period is used to allocate revenues.

Revenues for each tariff class are further split into meter provision, meter communication, meter reading and network use in order to allocate costs within contract and tariff customer classes to reference services.

The revenue allocation of operating and capital costs is presented in Table 11.4 in nominal dollars.[137]

[137] Assumes inflation of 2.09 per cent per annum.

Table 11.4 Revenue Allocation

$ million nominal	2010/11	2011/12	2012/13	2013/14	2014/15
Tariff	55.22	61.31	70.75	81.88	83.79
Contract	2.77	3.07	3.55	4.10	4.20
Contract- meter provision	0.37	0.41	0.47	0.54	0.56
Contract - meter communication	0.07	0.08	0.09	0.10	0.10
Contract - meter reading	0.03	0.04	0.04	0.05	0.05
Contract – network use	2.30	2.55	2.94	3.41	3.49
Tariff- meter provision	3.51	3.90	4.50	5.20	5.33
Tariff - meter reading	0.57	0.63	0.73	0.84	0.86
Tariff - network use	51.14	56.78	65.52	75.84	77.60

Note: ActewAGL Distribution has projected the earlier access arrangement period split between meter communications and meter provision for the access arrangement period.

11.2.3 Relationships between costs and revenues

In addition to a description of the proposed allocation of costs and revenues, the NGR require information on the relationship between costs and tariffs for tariff classes and reference services.[138] The NGR include requirements regarding costs and expected revenues from tariff classes and reference tariffs.

11.2.3.1 Standalone and avoidable costs

Rule 94 states that for each tariff class, the revenue expected to be recovered must lie between the standalone cost of providing the reference service to customers who belong to that class (upper bound) and the avoidable cost of not providing the reference service to those customers (lower bound).

The standalone cost for a tariff class is the cost that would be incurred if only that customer group were supplied. Any costs that would otherwise be shared with other customer groups would have to be fully attributed to the standalone customers. The standalone cost is effectively the cost of replicating or bypassing the infrastructure.[139] The avoidable cost for each tariff class is the cost that would be avoided if the customers in that class were removed from the network. Avoidable costs are therefore all costs that can be directly attributed to that customer group. Any cost incurred in jointly supplying other customers is not part of the avoidable cost, as it would still be incurred to supply the other customers.

The purpose of the standalone and avoidable cost test is to ensure that there are no cross subsidies between tariff classes. It is also designed to discourage inefficient bypass of the pipeline, which may occur if prices are above the standalone cost.[140] If any tariff class, or group of customers, is paying less than the lower bound of the avoidable cost, or the costs that arise directly from its use of the pipeline, then it is receiving a subsidy. If any tariff class

[138] Rule 72

[139] NERA 2006, *Distribution Pricing Rule Framework*, December, p. 22

[140] NERA 2006, *Distribution Pricing Rule Framework*, December p. 22

is paying more than the upper bound of the stand alone cost, or the cost if it alone was supplied, then it is subsidising other users. If the revenues from each group lie between the bounds of avoidable cost and stand alone cost, then each group is making some contribution to covering the joint or shared costs of supply. However, no group is receiving or paying an economic subsidy.

In applying this requirement to ActewAGL Distribution, it is important to note the dominance of the tariff market. The tariff segment of ActewAGL Distribution's gas market accounts for approximately 99.6 per cent of customers and 86 per cent of sales. Contract customers represent a very small part of the market and are allocated an appropriately small share of costs (as outlined in section 11.2.2 above).

The standalone cost for ActewAGL Distribution's tariff customers is therefore very close to the total cost of providing the network services. It is equal to total cost less those costs that are directly related to contract customers (and would not be incurred in the absence of the contract customers). The relevant contract customer costs to be deducted are the contract operating and meter costs.

The avoidable cost for the tariff customer class is the cost that would be avoided if tariff customers were not supplied. In principle, if tariff customers were excluded, then it would not be viable at all for ActewAGL Distribution to be supplying gas. In this sense the avoidable cost would be the full cost of the network—that is, without the tariff customers there would be no network and therefore all costs would be avoided. However, if it is assumed that the network would continue to exist, then avoidable costs for tariff customers would be defined as those costs which are directly attributable to tariff customers and hence would be avoided if they were not supplied. These avoidable costs would be the operating and meter costs.

Avoidable and standalone costs tariff classes are shown in Table 11.5.

Table 11.5 Avoidable and stand alone costs (2010/11)

$ million nominal	Avoidable Cost	Expected Revenue	Stand-alone Cost
Contract Class	1.39	3.07	39.33
Tariff Class	24.39	60.64	62.33

The expected revenue recovers the total cost of the contract and tariff class reference services. The stand alone cost for contract customers is calculated as the total cost less the avoidable cost of the tariff customers. Similarly, the stand alone cost for tariff customers is calculated as the total cost less the avoidable cost of the contract customers.

The costs and revenues of the contract class are derived from the Capacity Reservation Reference Service and the associated Meter Data Reference Service that relates to that service. While there are other Reference Services listed, there are no customers taking those services. The costs and revenues of the Tariff Class are derived from the Tariff Reference Service and the Meter Data Reference Service that relates to the tariff service.

The Meter Data Reference Service is an integral part of each of the pipeline services, as discussed above, and does not have its own avoidable or stand alone cost.

11.2.3.2 Long run marginal cost and transactions costs

The NGR also include requirements regarding long run marginal cost and transactions costs. Rule 94 says that each charging parameter for a tariff class must:

- take into account the long run marginal cost for the reference service or the element of the service to which the charging parameter relates; and
- be determined having regard to transaction costs and the ability of customers to respond to price signals.

The purpose of the long run marginal cost requirement is to ensure that prices signal to customers the forward-looking costs of expanding pipeline capacity, where appropriate.

Long run marginal cost is the cost of providing an increment in capacity. It includes the capital costs associated with the increment in capacity as well as the additional operating and maintenance costs. At times when pipeline utilisation is at or near capacity levels, prices should signal the costs of expanding capacity rather than the short run marginal costs which do not include capital related costs.

While the stand alone and avoidable cost requirement involves a specific requirement that revenues are within certain bounds (between stand alone and avoidable costs), the long run marginal cost requirement refers factors that are appropriate and necessary to be *taken into account*.

ActewAGL Distribution has provided indicative long run marginal costs of expanding the pipeline service to provide incremental capacity in the form of new customers. Excluding meter costs, these are estimated as follows:

- $1.24 per GJ to supply a government department;
- $2.28 per GJ to supply a retail market facility; and
- $4.64 per GJ to supply two residential developments estimated to supply 341 households.

These long run marginal costs are calculated as the amount per GJ required to recover the cost of the capital expenditure over a life of 15 years and applying a rate of interest assumed to be the post-tax nominal WACC of 11.09 per cent. They are the incremental cost of linking new customers to an existing pipeline network. They do not include the cost of providing the upstream network which is assumed to have the capacity to take the additional load. ActewAGL Distribution takes account of long run marginal cost, transactions costs and price responsiveness when setting reference tariffs. Reference Tariffs recover the long run marginal cost or the incremental cost of a new customer or group of customers. In addition, they must recover the cost of providing the upstream network. Therefore, Reference Tariffs must be higher than the long run marginal cost.

11.2.3.3 Charging parameters

Contract customers have a choice of two charging parameters, a capacity charge and a throughput charge. The capacity charge reflects the cost of providing capacity and provides an incentive for contract customers to manage their daily demand. The Throughput Reference Service would suit a customer with a variable load as it has only a throughput charge and does not have a capacity charge. There are no customers in the ACT region that have chosen this service.

Contract customers have separate parameters for meters that reflect the varying cost of meters with different capacities. Meter communications costs and meter reading costs do not vary with the capacity of the meter. However, where a customer has multiple meters and multiple meter sites, meter communications and meter reading charges may apply to each meter, depending upon the location of the meters.

Reference tariffs for tariff customers have fixed, throughput, metering and meter reading parameters. They do not include capacity charges. ActewAGL Distribution has assessed that the transactions costs involved in moving from the relatively simple tariff structure, comprising a throughput charge and a fixed charge, to one with capacity charges would more that offset any potential benefits of signalling the cost of providing capacity, particularly when capacity constraints are not binding. Relevant transactions costs include the costs of more sophisticated metering, the costs of more complex billing and the costs to customers of understanding, and responding to, a more complicated tariff structure.

The fixed charge signals the cost of connecting and maintaining a connection service to the consumer. Where a customer does not require a service, it encourages the customer to disconnect and lower the cost of providing network services.

There are 4 price steps in the throughput charges for the tariff service. The first two price steps are of most relevance to the majority of residential consumers. The first step is the highest and is the marginal price faced by consumers consuming at the rate of up to 15 GJ per annum such as those that may use gas only for cooking. Customers with this level of consumption have a more price inelastic load. About 25 per cent of the residential load is consumed in this price step and 2 per cent of the business load.

The second step is 21 per cent lower than the first step and applies to around 75 per cent of the residential load and 47 per cent of the business load. It is the marginal cost faced by customers consuming at the rate of more than 15 GJ and less than 1 TJ per annum. Residential customers faced with this step are known to be relatively more price sensitive. It is the marginal price that is likely to apply to residential consumers with space heating and hot water appliances. It is also the marginal price that is faced by most small business consumers.

The third step is 9 per cent lower than the second step and applies to 39 per cent of the business load. It is the marginal price faced by larger, primarily business, customers consuming at the rate of more than 1 TJ and less than 5 TJ per annum.

The fourth step is 30 per cent lower than the third step and applies to 13 per cent of the business load. It is the marginal price faced by customers consuming at the rate of more than 5 TJ per annum who do not qualify or have not moved to a contract service. This step is the intermediate rate between tariff services and contract services.

There are two metering charge options for tariff customers. For those with a meter capacity of less than 6 cubic meters per hour, there is a fixed annual charge. For meters with a capacity of more than 6 cubic meters per hour, the metering charge is based upon the throughput. There are two meter reading charge options for tariff class customers depending upon whether the meter is read quarterly or monthly.

11.2.3.4 Revenue equalisation

Rule 92(2) requires that the reference tariff variation mechanism be designed to equalise (in terms of present values) forecast revenue from reference services over the access arrangement period; and the portion of total revenue allocated to reference services for the access arrangement period.

Capacity reservation service

The revenue requirement for the capacity reservation service customers using the building block approach for contract customers is as shown in Table 11.6.

Table 11.6 Revenue requirement for capacity reservation service customers

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Contract revenue	2.66	2.96	3.41	3.95	4.04

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $12.27 million.

The proposed revenue stream in nominal dollars using the building block approach for contract customers is as per Table 11.7.

Table 11.7 Proposed revenue stream for capacity reservation service customers

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Contract revenue	2.95	3.14	3.35	3.58	3.84

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $12.27 million which is equal to the revenue requirement.

Tariff service

The revenue requirement for the tariff service customers in nominal dollars using the building block approach for contract customers is as per Table 11.8.

Table 11.8 Revenue requirement for the tariff service customers

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Tariff revenue	54.65	60.68	70.02	81.04	82.93

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $251.66 million.

The proposed revenue stream for the tariff service customers in nominal dollars using the building block approach for contract customers is as per Table 11.9.

Table 11.9 Proposed revenue stream for tariff service customers

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Tariff revenue	59.99	63.93	68.65	73.97	79.88

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $251.66 million which is equal to the revenue requirement.

Meter data service

The revenue requirement for the meter data service in nominal dollars using the building block approach for contract customers is as per Table 11.10.

Table 11.10 Revenue requirement for the meter data service

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Meter data revenue	0.671	0.745	0.859	0.995	1.018

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $3.09 million.

The proposed revenue stream for the meter data service in nominal dollars using the building block approach for contract customers is as per Table 11.11.

Table 11.11 Proposed revenue stream for the meter data service

$million nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Meter data revenue	0.771	0.806	0.845	0.884	0.923

When discounted at the nominal vanilla WACC of 11.09 per cent, the net present value of these revenues is $3.09 million which is equal to the revenue requirement.

Other reference services

While there are other reference services available, there are no customers taking those services or expected to take them.

11.3 Reference tariff variation

This section sets out ActewAGL Distribution's proposed reference tariff variation mechanisms for the access arrangement. Rule 97 provides for the inclusion of reference tariff variation mechanisms in an access arrangement. ActewAGL Distribution has included two tariff variation mechanisms as part of its access arrangement:

1. The annual reference tariff adjustment formula mechanism; and
2. A cost pass-through mechanism.

These are discussed below.

11.3.1 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 access arrangement. ActewAGL Distribution proposes to include an annual tariff variation adjustment formula in its reference tariff variation mechanism in the access arrangement.

ActewAGL Distribution's previous access arrangement included an annual tariff variation formula in its tariff variation mechanism to escalate prices by CPI. ActewAGL Distribution proposes to retain this annual tariff variation adjustment, but add four parameters to the mechanism to take account of:

- The difference between forecast and actual costs for three specified externally determined charges (Part 1):
    - the AEMO fee;
    - the UNFT; and
    - the Energy Industry Levy; and
- A UAG parameter, being the difference between UAG forecast as 1.8 per cent of actual network gas receipts at $9.10 (2009/10 dollars) per GJ and 1.8 per cent of actual network gas receipts at the efficient tendered market price per GJ (Part 2).

The application of these parameters vary tariffs on an annual basis in a single annual tariff variation formula mechanism.

11.3.1.1 Specified externally-determined charges adjustment part

ActewAGL Distribution proposes to include an adjustment in its annual tariff variation formula to account for differences between forecast amounts for three specified externally determined charges and those amounts actually paid. ActewAGL Distribution has proposed this adjustment to ensure that it and users do not face forecasting risk for costs that are not within ActewAGL Distribution's control. This provides a benefit to both ActewAGL Distribution and users, in that neither is exposed to the risk of under or over recovery of these costs, which are not correlated with efficiency performance.

ActewAGL Distribution considers that this approach is consistent with the NGL Objective, and with Rule 97(3)(a), which requires the AER to have regard to the need for efficient tariff structures in deciding on a reference tariff variation mechanism.

ActewAGL Distribution notes that the AER rejected its proposal for a similar adjustment mechanism in respect to the UNFT in its final decision on the ACT electricity network price determination. In doing so, the AER stated that it "did not consider that the transitional chapter 6 rules allowed the pricing process to be used to adjust for expenditure other than TOUS charges".[141] ActewAGL Distribution does not consider that the AER is subject to the some limitation in respect to this proposed adjustment factor in the access arrangement, as the NGR clearly provide for this type of adjustment mechanism.[142]

ActewAGL Distribution further notes that, in rejecting its proposed adjustment mechanism for the UNFT, the AER did not question the appropriateness of adjusting for changes in the UNFT, just its ability to approve a specific adjustment mechanism. The AER instead suggested that, as the UNFT may vary as a result of a change in a determined rate set by the ACT Government, "the transitional chapter 6 rules allow ActewAGL to apply for a cost pass through, as a tax change event"[143].

While ActewAGL Distribution notes that a similar approach could be adopted in this access arrangement through the operation of the Change in taxes pass through event discussed below, ActewAGL Distribution considers this to be an inferior outcome to including an adjustment factor in the annual tariff formula. ActewAGL Distribution considers that the operation of an annual tariff variation formula imposes lower administrative costs for both ActewAGL Distribution and the AER than the cost pass through assessment process. This is because differences between forecast and actual costs associated with the specified charges can be readily determined and verified, and therefore detailed analysis of the kind that usually characterises pass through applications is not necessary. The operation of a formula is also more transparent to users and prospective users.

In the event that the AER does not approve this adjustment, changes in these costs are expected to be managed through cost pass through mechanisms discussed further below.

11.3.1.2 Unaccounted for gas adjustment part

ActewAGL Distribution proposes also to include an adjustment in its annual tariff variation formula to account for differences between an efficient benchmark level of UAG at a forecast price and at the actual market price.

As the price of UAG is not a matter that can be controlled by ActewAGL Distribution, Reference Tariffs should be allowed to be varied consistent with the actual price of UAG at

[141] AER 2009, Australian Capital Territory distribution determination 2009-10 to 2013-14, Final Decision, p 70
[142] NGR 97(1)(b)
[143] AER 2009, Australian Capital Territory distribution determination 2009-10 to 2013-14, Final Decision, p 71

the time of annual tariff variations on the basis that ActewAGL Distribution has used reasonable endeavours to purchase gas at the lowest available prices. A methodology similar to that in JGN's 2004 access arrangement provides an example of a useful approach. ActewAGL Distribution therefore further proposes that:

- the purchase price of UAG be passed through in reference tariffs based on ActewAGL Distribution's actual purchase price on the condition that ActewAGL Distribution has undertaken a sound commercial process designed to achieve the lowest available price in the market;[144] and
- a tariff adjustment mechanism be approved for variation in the actual price of UAG from the forecast price. The variation due to quantity is removed from the adjustment by applying the actual and forecast price to the actual gas receipts.

11.3.1.3 Proposed annual tariff variation formulae

In accordance with the earlier access arrangement period, ActewAGL Distribution proposes that all Reference Tariffs be varied by CPI each year. The specified externally determined charges part and the UAG part (collectively, the "Adjustment factor"), however, will only apply to Reference Tariffs that relate to capacity and throughput. This is appropriate as these costs most closely relate to the network, as opposed to metering, meter reading or fixed charges that have been maintained constant in real terms.

Therefore, capacity and throughout tariffs are proposed to be varied in accordance with the following formula:

$$P_t = P_t^*(1 + CPI_t)(1 + A_t)$$

Where:

P_t	is the varied reference tariff in year t;
P_t^*	is the unadjusted and published reference tariff;
CPI_t	the CPI in year t relative to the base year prices;
A_t	is the Adjustment Factor in year t; and
t	is the financial year for which reference tariffs are being set.

All other Reference Tariffs (such as metering charges), will be varied in accordance with the following formula:

$$P_t = P_t^*(1 + CPI_t)$$

CPI is calculated in accordance with a formula in the access arrangement as follows:

$$CPI_t = \left(\frac{CPI_{Mar\ t-2} + CPI_{Jun\ t-2} + CPI_{Sep\ t-1} + CPI_{Dec\ t-1}}{CPI_{Mar2008} + CPI_{Jun2008} + CPI_{Sep2008} + CPI_{Dec2008}} - 1 \right)$$

The Adjustment Factor is calculated in accordance with the following formula:

[144] Based on the most recent tenders for UAG, the forecast price for UAG be \$9.10/GJ (\$2009/10)

$$A_t = \left(\frac{(U_{t-2} - U^*_{t-2} + F_{t-2} - F^*_{t-2} + T_{t-2} - T^*_{t-2} + L_{t-2} - L^*_{t-2})(1+r)^2}{ER^*_t} \right)$$

U_{t-2} is the actual cost to ActewAGL Distribution of UAG in year t-2. The actual cost of UAG is 0.018 times actual gas receipts (GJ) times the market price per GJ paid by ActewAGL Distribution at the relevant time;

U^*_{t-2} is the forecast value of UAG in year t-2. The forecast value of UAG is 0.018 times actual gas receipts (GJ) times the base price per GJ adjusted for CPI in year t-2. Base price per GJ is defined as $9.10/GJ (in real 2009/10 dollars);

F_{t-2} is the actual cost to ActewAGL Distribution of AEMO fees in connection with the gas distribution business as determined by AEMO in year t-2;

F^*_{t-2} is the forecast cost used to derive the Reference Tariffs in the access arrangement (adjusted for CPI to year t-2) to ActewAGL Distribution of AEMO fees in connection with the gas distribution business for year t-2;

T_{t-2} is the actual cost to ActewAGL Distribution of UNFT in connection with the gas distribution business in year t-2;

T^*_{t-2} is the forecast cost used to derive the Reference Tariffs in the access arrangement (adjusted for CPI to year t-2) to ActewAGL Distribution of UNFT in connection with the gas distribution business in year t-2;

L_{t-2} is the actual cost to ActewAGL Distribution of the Energy Industry Levy in connection with the gas distribution business in year t-2;

L^*_{t-2} is the forecast cost used to derive the Reference Tariffs in the access arrangement (adjusted for CPI to year t-2) to ActewAGL of the Energy Industry Levy in connection with the gas distribution business in year t-2;

r is the weighted average cost of capital used to derive the Reference Tariffs in the access arrangement, the nominal vanilla WACC;

ER^*_t is the forecast energy revenue from Reference Tariffs relating to capacity and throughput in year t assuming that the adjustment factor A_t were equal to zero (ie adjusted for CPI only).

By virtue of the application of the Adjustment factor, relevant reference tariffs are first varied by this part of the formula (accounting for UAG and specified charges) in year 3 of the access arrangement period.

The formulae also take account of the time value of money by including an adjustment for the WACC. The cost of capital is squared in this adjustment because two years elapse between the time that the additional cost is incurred and when it is recovered. The formula is intended to make ActewAGL Distribution neutral to the effect of increments and decrements between forecast and actual values for these parameters.

For the purposes of the specified charges adjustment part, the forecast costs for the three specified externally determined charges are shown in Table 11.12.

Table 11.12 Forecast costs of specific externally determined charges ($2009/10)

Year	2010-11	2011-12	2012-13	2013-14	2014-15
Australian Energy Market Operator	$42,413	$92,883	$92,862	$92,841	$92,820
Utilities Network Facilities Tax	$3,407,614	$3,457,482	$3,508,079	$3,559,417	$3,611,506
Energy Industry Levy	$532,192	$532,065	$531,942	$531,821	$531,704

11.3.2 Cost pass through mechanism

Rule 97(1)(c) specifically allows a service provider to propose in the access arrangement a reference tariff variation mechanism that allows tariffs to vary as a result of a cost pass-through for a defined event. The Rules do not define or limit the types of events for which a cost pass-through mechanism may be adopted, however Rule 97(3) requires that, in deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to:

(a) the need for efficient tariff structures; and

(b) the possible effects of the mechanism on administrative costs of the AER, the service provider, and users or potential users; and

(c) the regulatory arrangements (if any) applicable to the relevant reference services before the commencement of the proposed mechanism; and

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

(e) any other relevant factor.

Rule 97(4) also requires that “a reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff”.

The purpose of the cost pass through mechanism is to ensure ActewAGL Distribution can recover incremental costs resulting from a relevant pass-through event. ActewAGL Distribution does not intend for the existence of the cost pass-through mechanism to adversely impact upon ActewAGL Distribution’s efficiency, risk management decisions or its decision to take reasonable action to reduce the magnitude of an adverse event. This section discusses ActewAGL Distribution’s proposed cost pass through tariff adjustment mechanism.

11.3.2.1 Proposed cost pass through events

ActewAGL Distribution proposes that the events listed in Table 11.13 be eligible for cost pass through for the purposes of the access arrangement. To this end, and in accordance with the requirements and guidance set out above, this section:

- defines the proposed pass-through events;
- sets out ActewAGL Distribution’s reasoning and justification for proposing these events be treated as cost pass-through events, with specific reference to the factors contained in Rule 97(3); and

- explains how each proposed event is relevant to a building block component and is either foreseen or unforeseen and that the costs of the event are uncontrollable and therefore would not be appropriate to include in forecasts for total revenue.

Defining the proposed pass through events

ActewAGL Distribution has included the following seven cost pass-through events in its access arrangement:

- Change in taxes event;
- Service standard event;
- Regulatory change event;
- Carbon Pollution Reduction Scheme event;
- National Energy Customer Framework or National Energy Connections Framework event;
- A Short Term Trading Market Event; and
- General nominated pass through event.

Table 11.13 sets out the definitions for each of these cost pass through events.

Table 11.13 Definitions of cost pass through events

Event name	Definition
Change in tax event	Change in Tax Event means: (a) a change in the amount of a Relevant Tax, or the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of a Relevant Tax), except where the change falls within the scope of the Annual Reference Tariff Variation Formula Mechanism; or (b) the removal of a Relevant Tax or imposition of a new Relevant Tax. which, in each case, occurs after the Commencement Date of the Access Arrangement. Relevant Tax means any tax (including any rate, duty, charge or levy or other like impost) that is imposed by or payable directly or indirectly by ActewAGL to the Commonwealth of Australia, a State or Territory, or an Authority of the Commonwealth or of a State or Territory (including goods and services tax), but excluding: (a) income tax (or State or Territory equivalent income tax) or capital gains tax; (b) stamp duty, financial institutions duty, bank account debits tax or similar taxes or duties; (c) penalties and interest for late payment relating to any tax; and (d) any tax which replaces a tax referred to in (a) - (c) above, where “tax” includes any rate, duty, charge or other like impost.
Service standard event	Service Standard Event means any decision made by the Relevant Regulator or any other Authority, or any introduction of or amendment to applicable law or Gas Law, which: (a) has the effect of: (i) imposing or varying standards (including Network Design and operational standards) on ActewAGL relevant to any one or more of the Services, that are more onerous than the standards imposed at the Commencement Date; or (ii) altering the nature or scope of services that comprise any one or more of the Services; or (iii) substantially altering the manner in which ActewAGL is required to undertake any activity forming part of, or ancillary to, any one or more of the Services (including through rules for the operation of competitive gas markets); and (b) results in ActewAGL incurring (or being likely to incur) materially higher costs in providing any one or more of the Services than it would have incurred but for that event.
Regulatory change event	Regulatory Change Event means a change in a regulatory obligation or requirement that: (a) substantially affects the manner in which ActewAGL provides the Services (or any one of them) or otherwise operates its gas business (or any part of it); (b) materially increases or materially decreases the costs of providing those Services or operating its business; and (c) does not fall within any other category of Cost Pass Through Event under this clause.
Carbon Pollution Reduction Scheme event	Carbon Pollution Reduction Scheme Event means an event which results in the imposition of legal obligations on ActewAGL or a third party arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth, a State or Territory or an Authority and results in ActewAGL incurring costs directly or indirectly (including under statute or contract) and includes: (a) the cost of acquiring emissions allowances, permits or units (howsoever called); (b) costs incurred in order to reduce liability for carbon emissions associated with the production, transport or supply of gas, or otherwise in connection with ActewAGL’s gas distribution business or the Services; and (c) administrative and compliance costs associated with the introduction or operation of such a scheme, including reporting costs.
An NECF or NGCF event	National Energy Customer Framework/ National Energy Connections Framework Event means the introduction of new laws (including through proposed National Energy Retail Law and Rules, or by additions or changes to the National Gas Law or Rules) or

Event name	Definition
	additions or changes to the existing Gas Law, to implement either or both of the proposed National Energy Customer Framework or National Energy Connections Framework, which results in the imposition of legal obligations on ActewAGL or a third party and results in ActewAGL incurring costs directly or indirectly (including under statute or contract) from the operation of those frameworks.
An STTM event	Short Term Trading Market Event occurs if any part of ActewAGL's Network is made or becomes part of a trading hub under the gas Short Term Trading Market operated by the Australian Energy Market Operator, or ActewAGL otherwise participates in that Short Term Trading Market, resulting in: (a) changes in costs that ActewAGL incurs directly or indirectly (including under statute or contract); or (b) the need to change services provided to accommodate the market, leading to additional costs.
General pass through event	General Pass-Through Event occurs in the following circumstances: (a) an uncontrollable and unforeseeable event that falls outside of the normal operations of a business such that prudent operational risk management could not have prevented or mitigated the effect of the event; (b) which results in a material change in the cost of providing the Services (or any of them) or the operation of its gas business (or any part of it); and (c) does not fall within any other category of Cost Pass Through Event under this clause.

Justification for and nature of proposed cost pass through events

Merits of using cost pass through to manage exogenous risk

It is well understood that regulated businesses face a number of legitimate risks as part of their normal business that are not covered by the rate of return set under the regulatory framework. This means the businesses must be compensated for the cost of these risks through other aspects of the regulatory arrangements.

Risk mitigation options include self insurance, direct insurance, a cost pass-through mechanism and including the expected value of the costs associated with various risk(s) in the business's expenditure forecasts (submitted as part of the access arrangement approval process). A cost pass-through mechanism allows for the pass-through of the cost of certain defined events in tariffs during the access arrangement period, if and when such events in fact occur.

Providing for cost pass-through events involves an administrative burden, both upfront (to the extent the regulator must approve the specific events that will trigger the cost pass-through mechanism for that regulatory period), and more significantly in the instance the event actually materialises (and the regulator must assess the validity of the pass-through event and determine any efficient pass-through amount to be allowed). Where the costs of an event are relatively low and/or the options of direct insurance or self insurance are feasible, direct insurance or self insurance may be preferred to a cost pass through mechanism, as they impose a lower administrative burden in the case that the event occurs.

However, where a particular exogenous event is associated with a *material* impact on costs, the cost of direct insurance is likely to be substantial and it is unlikely to be credible for the business to self insure, as it may not be able to bear the costs if the event actually occurred. In these cases a cost pass-through event is likely to be the most appropriate option for managing that risk.

Cost pass-through events, including those proposed in Table 11.13, may materially increase or decrease ActewAGL Distribution's capital expenditure and/or operating expenditure beyond the levels that were provided for in the access arrangement. Cost pass through events are either foreseen (for example, the Carbon Pollution Reduction Scheme Event) or unforeseen (for example, the circumstances covered by the general pass-through event), and the cost of these events are uncertain and uncontrollable. By consequence, it is not appropriate to include estimates of these costs within the expenditure forecasts.

<u>Current cost pass through arrangements for ActewAGL Distribution</u>

Under the earlier access arrangement, a cost pass-through event is defined as either a:

- change in tax event (defined as Table 11.13);
- service standard event (defined as in Table 11.13); or
- terrorism or major natural disaster event, where a terrorism or major natural disaster event is "an act of terrorism or a major natural disaster (including, but not limited to, fire, flood or earthquake) which results in costs which are substantially different from those reasonably foreseen by the commission and ActewAGL Distribution and incorporated in this price direction."

Under NGR 97(3)(c), in considering any proposal for a cost pass-through mechanism the AER is to consider, "the regulatory arrangements (if any) applicable to the relevant reference services before the commencement of the proposed reference tariff variation mechanism". ActewAGL Distribution considers that a 'change in tax event' and a 'service standard event' should remain eligible cost pass-through events for the access arrangement period. These events have the potential to result in material, unforeseen costs over the access arrangement period. ActewAGL Distribution has amended the definition of a Change in tax event, however, to reflect the operation of its proposed annual tariff variation formula.

ActewAGL Distribution further notes that these two events are also defined cost pass through events under the National Electricity Rules (see below) and, as a result, apply to ActewAGL Distribution's electricity network business. They are also included as cost pass-through events in the access arrangements applying to gas distributors in other jurisdictions. Under NGR 97(3)(d), in considering any proposal for a cost pass through mechanism the AER is to consider: "the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)".

As discussed in section11.3.1.1, ActewAGL Distribution has proposed that a separate tariff variation mechanism be applied to adjust tariffs for changes in the UNFT imposed on ActewAGL Distribution's gas distribution business, as well as changes in the Energy Industry Levy, and AEMO fees. ActewAGL considers that an automatic formula based adjustment is the appropriate approach to dealing with the expected changes in the level of these charges during the access arrangement period, as it results in a lower administrative cost than if these are treated as a cost pass-through event.

However, in the event that the AER does not accept ActewAGL Distribution's proposed specified externally-determined charges adjustment factor to take account of differences between forecast and actual amounts of these externally imposed charges, ActewAGL Distribution would expect to be able to recover these costs through the cost pass-through mechanism, as a change in tax event, and would amend the proposed definition accordingly. This is consistent with the AER's Final Decision for ActewAGL Distribution's electricity distribution business, in which it states:

> The AER notes that the UNFT liability may vary due to a change in the determined rate set by the ACT Government. In such a circumstance, the transitional chapter 6 rules allow ActewAGL to apply to the AER for a cost pass through, as a tax change event. The AER will consider any pass through application in respect of these costs on its merits, at the time the application is made to the AER.[145]

However, where the AER accepts the charges adjustment factor, the change in tax event would apply to any changes in taxes or the introduction of new taxes outside of those covered by the factor.

As noted above, ActewAGL Distribution's earlier access arrangement also includes a 'terrorism or major natural disaster event'. ActewAGL Distribution notes that a 'terrorism event' is a defined cost pass-through event under the National Electricity Rules (see below).

The events captured under the current definition of 'terrorism or major natural disaster event' would lead to material and uncertain and uncontrollable costs for ActewAGL Distribution's gas distribution business. As a result, ActewAGL Distribution considers that it continues to be appropriate to capture these events within the cost pass-through mechanism. However, ActewAGL Distribution notes that in the AER's recent Final Decisions for ActewAGL Distribution's electricity network business and for the NSW electricity distribution businesses, the AER's preferred approach is to include a pass-through for natural disasters within a broader category of 'general nominated pass-through event':

> The AER considers that there is a risk in attempting to capture all natural disaster type events in a single definition. It would be undesirable for a similar event occurring in two jurisdictions to be recoverable under the pass through provisions in one jurisdiction, and not recoverable in another jurisdiction based simply on the drafting of the event. Rather than attempting to capture all appropriate events in a specific definition, the AER considers that these types of events should be considered under the general nominated pass through event if they occur.[146]

ActewAGL Distribution has therefore adopted this approach in its access arrangement. ActewAGL Distribution considers that the 'general pass-through event' would also apply to terrorism events. The proposed general pass-through event is discussed further below.

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[145] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14, April 2009*, p. 71
[146] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 134-5

Regulatory arrangements for similar services

ActewAGL Distribution considers that the cost pass through provisions included in the earlier access arrangement require change. The current limited definitions of cost pass through events leave ActewAGL Distribution exposed to a wide range of exogenous risks. In addition, given that a number of electricity and gas distribution and transmission businesses have been subject to regulatory review since 2004, there are now material differences between the cost pass through arrangements applying to ActewAGL Distribution, and those in place for similar businesses.

Under NGR 97(3)(d), in considering any proposal for a cost pass through mechanism the AER is to consider "the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)".

The National Electricity Rules provides for two categories of pass through events in electricity distribution:

- Defined events—the following four events are set out in chapter 10 of the NER as pass through events:
    - a regulatory change event;
    - a service standard event;
    - a tax change event;
    - a terrorism event; and
- Nominated pass through events:
    - other events that the DNSPs may propose to the AER to include as 'nominated pass through events' in its determination.

It is in this context that ActewAGL Distribution considers that it is appropriate to define a 'regulatory change event' in respect of this access arrangement, consistent with defined events applying to electricity distribution businesses.

In relation to nominated pass-through events, ActewAGL Distribution notes that the following pass-through events are amongst those that have recently been approved by the AER in its final decisions for ActewAGL Distribution's electricity network business and the NSW electricity network businesses:

- Emissions trading scheme event; and
- A general nominated pass-through event.

In approving these events, the AER noted that pass through events could be classed as either foreseeable or unforeseeable, and that different approaches were appropriate for each of these types of events.[147]

[147] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, pp 127-8

In particular, the AER recognised that some events could be anticipated as likely to occur within a period, but that the timing and/or the cost impact may be unforeseeable at the time of lodgement of the regulatory proposal. In respect of these *foreseeable* events (also classed as specific nominated events), the AER concluded:

> …the AER considers it preferable that these costs be included when the costs of these activities are able to be forecast on a reasonable basis and when the timing of these events is known with certainty.[148]

The AER further stated:

> The costs associated with these events would have been included, without regard to the materiality of the financial impact of the event on the DNSP, had the necessary information been available at the time of the final decision.[149]

A key factor in identifying a foreseeable event was that "at the time the AER makes its distribution determination, the event was more likely than not to occur during the regulatory control period".[150]

In respect of *unforeseeable* events, the AER recognised the possibility of events occurring during the regulatory period that are uncontrollable, unforeseen and which have a material impact on costs. For these events, the AER concluded:

> 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 or the NER, it is appropriate that costs associated with the event should be passed through to consumers.[151]

By virtue of being unforeseeable, the AER considered that there were specific difficulties in trying to define appropriate pass-through events:

> An unforeseeable event that materially impacts on a DNSP's ability to provide direct control services should not be precluded from pass through solely on the basis that is [sic] not possible to specifically define the event in advance of its occurrence.[152]

A key factor in indentifying an unforeseeable event was "if, at the time of submitting a regulatory proposal, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the regulatory control period".[153]

The AER approved *Emissions trading scheme event* was deemed an example of a foreseeable pass-through event, and the *general nominated pass through event* was developed as a way to address uncertainty in defining specific unforeseeable pass-through events.

It is in this context that ActewAGL Distribution considers that, in addition to the 'Regulatory Change Event' discussed above, it is appropriate to define a 'Carbon Pollution Reduction

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[148] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 128
[149] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 130
[150] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 128
[151] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 128
[152] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 127
[153] AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 129

Scheme Event', a 'National Energy Customer Framework or National Gas Connections Framework Event' and a 'Short Term Trading Market Event' as foreseeable pass through events in the access arrangement. In addition, ActewAGL Distribution considers that it appropriate to define a 'general pass through event' to address unforeseeable events in the access arrangement.

These events are discussed below.

Regulatory change event

Regulatory change event is defined in the NER as:

> A change in a regulatory obligation or requirement that:
>
> (a) falls within no other category of pass through event; and
>
> (b) occurs during the course of a regulatory control period; and
>
> (c) substantially affects the manner in which the Transmission Network Service Provider provides prescribed transmission services or the Distribution Network Service Provider provides direct control services (as the case requires); and
>
> (d) materially increases or materially decreases the costs of providing those services.

This cost pass-through category currently applies to a number of electricity distribution businesses, including ActewAGL Distribution's electricity distribution business and those of the NSW DNSPs. However, in addition to enhancing consistency between regulatory arrangements for similar services, defining a 'regulatory change event' as an eligible cost pass through event in the access arrangement is also important in the context of reducing ActewAGL Distribution's exposure to regulatory events that are outside of the businesses' control, that are *not* captured by any other category of eligible pass through event, but that could materially impact on the financial viability of ActewAGL Distribution. It can reasonably be expected that there will be regulatory change events occurring during the access arrangement period, however the precise nature of those events and the costs that they may give rise to are not currently foreseeable. An example of a foreseeable regulatory change event, also described in chapter 4 of this access arrangement proposal, is the introduction of new gas fitting rules in the ACT during the access arrangement period, or new climate change, energy efficiency or other environmental obligations.

Carbon Pollution Reduction Scheme Event

To provide for the pass-through of costs associated with meeting any future CPRS, ActewAGL Distribution proposes that a carbon pollution reduction scheme event be included as a pass through event. Relevant costs covered by this event include the direct costs of buying permits, costs incurred in order to reduce carbon emissions, and administrative costs of the scheme.

Under the Federal Government's CPRS, now due to commence in July 2011, it is expected that gas distribution businesses will incur costs associated with the CPRS, both directly and through third parties, associated with the requirement for permits in line with emission liabilities.

ActewAGL Distribution also notes that there is significant scope for schemes in NSW or the ACT to have a similar effect, either in conjunction with, or instead of, a federal scheme. As highlighted in section 4.3.4.2 of this access arrangement information, the ACT Government has in place a long term strategy for climate change which includes jurisdictional targets for emissions reductions. Details of future policies in respect of climate change, in particular through the current inquiry into ACT Greenhouse Gas Reduction Targets, may also yield further emission reduction targets or schemes.

ActewAGL Distribution considers that the imposition of a CPRS or similar scheme by the Commonwealth, a State or Territory or an Authority, is more likely than not to occur in the access arrangement period. This event should therefore be considered as a foreseeable event.

In line with the AER's recent decision with respect of the NSW and ACT distribution businesses to approve an emissions trading event as a nominated pass through event, ActewAGL Distribution proposes to include a carbon pollution reduction scheme event in its access arrangement as follows:

> **Carbon Pollution Reduction Scheme Event** means an event which results in the imposition of legal obligations on ActewAGL or a third party arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth, a State or Territory or an Authority and results in ActewAGL incurring costs directly or indirectly (including under statute or contract) and includes:
>
> (a) the cost of acquiring emissions allowances, permits or units (howsoever called);
>
> (b) costs incurred in order to reduce liability for carbon emissions associated with the production, transport or supply of gas, or otherwise in connection with ActewAGL's gas distribution business or the Services; and
>
> (c) administrative and compliance costs associated with the introduction or operation of such a scheme, including reporting costs.

The definition proposed by ActewAGL Distribution is consistent with that approved by the AER for the NSW DNSPs and ActewAGL Distribution's electricity distribution business, however some enhancements have been made to provide further clarity of the types of costs to be covered by the proposed event. This includes ensuring that the incentives intended under the CPRS to take action to reduce emissions where the costs of these actions is less then the costs of permits, is retained.

National Energy Customer Framework or National Gas Connections Framework Event

As outlined in chapter 4, the MCE SCO is currently developing a new National Energy Customer Framework, and a National Gas Connections Framework. Legislation and Rules associated with both frameworks are expected to be introduced into the South Australian Parliament in 2010. While ActewAGL Distribution has engaged with officials in the development of these frameworks, there is still considerable uncertainty as to their final form. In addition, no details are currently available on transitional arrangements associated with these frameworks.

Due to the timing of the legislation, and lack of detail as to transitional arrangements, ActewAGL Distribution considers that there is a reasonable possibility that they will come into effect during the access arrangement period. The imposition of one or both of these frameworks should therefore be considered as a foreseeable pass-through event.

ActewAGL Distribution has included a pass-through event associated with these frameworks in the access arrangement as follows:

> **National Energy Customer Framework/ National Energy Connections Framework Event** means the introduction of new laws (including through proposed National Energy Retail Law and Rules, or by additions or changes to the National Gas Law or Rules) or additions or changes to the existing Gas Law, to implement either or both of the proposed National Energy Customer Framework or National Energy Connections Framework, which results in the imposition of legal obligations on ActewAGL or a third party and results in ActewAGL incurring costs directly or indirectly (including under statute or contract) from the operation of those frameworks.

ActewAGL Distribution considers that a specific pass through event is appropriate to address this risk due to the potential for the new framework to significantly change the scope and application of the current rules, including the scope of reference services, liabilities and risks faced by the business.

These types of costs may not be covered by ActewAGL Distribution's proposed regulatory change event, which explicitly refers to events that increase or decrease costs of providing *reference services*. Changes to the definition of references services, which is clearly within the scope of possible changes under the NECF and NGCF, and associated costs, may therefore not be captured under this generic pass-through provision. A specific pass through event is therefore included in the access arrangement.

<u>Short Term Trading Market Event</u>

The STTM will come into effect in July 2010 with two trading hubs; one in Sydney and one in Adelaide. As outlined in Chapter 4, there is a possibility that Canberra will become a trading hub during the access arrangement period or that ActewAGL Distribution is otherwise required to participate in the STTM. ActewAGL Distribution considers that this should be considered as a foreseeable pass through event.

ActewAGL Distribution has included a pass through to apply in the event that ActewAGL Distribution is required to take part in the STTM during the access arrangement period as follows:

> **Short Term Trading Market Event** occurs if any part of ActewAGL's Network is made or becomes part of a trading hub under the gas Short Term Trading Market operated by the Australian Energy Market Operator, or ActewAGL otherwise participates in that Short Term Trading Market, resulting in:
>
> (a) changes in costs that ActewAGL incurs directly or indirectly (including under statute or contract); or

> (b) the need to change services provided to accommodate the market, leading to additional costs.

ActewAGL Distribution considers that a specific pass-through event is appropriate to address this risk as it is unclear whether the regulatory change event defined above would adequately encompass changes to services anticipated under the STTM. These could include changes to reference services, particularly in respect of capacity reservation services or gas storage. ActewAGL Distribution therefore considers that a specific pass-through mechanism is appropriate for inclusion in the access arrangement.

Supply curtailment event

ActewAGL Distribution has noted in several parts of this access arrangement information that the ACT, Queanbeyan and Palerang gas network is particularly susceptible to upstream events that could lead to a shortfall in supply to the ACT.

The ACT Government has in place regulations under the *Utilities Act 2000* to allow the responsible minister to approve a scheme to restrict the use of gas in the ACT in the event of a shortage.[154]

It could take weeks or months to reinstate network operations and customer supply in the event of a sustained disruption that led to the need to curtail significant numbers of customers. ActewAGL Distribution's *Contingency Plan* sets out expected supply losses and estimates of restoration times in the event of various emergency scenarios.

ActewAGL Distribution proposed a supply curtailment event as part of its electricity network regulatory proposal submitted to the AER in June 2008. The AER, however, rejected this proposal in its Draft Decision, stating:

> …the AER considers that no provision is made in the NER for DNSPs to recover foregone revenue through a pass through mechanism. The transitional chapter 6 rules specifically confine pass through events to event that materially increase or decrease the costs of providing direct control services. [155]

ActewAGL Distribution remains of the view that a supply curtailment pass through event is the most appropriate way to manage the risk of a widespread shortfall in gas supply that leads to a sustained disruption of customers.

While ActewAGL Distribution notes that the NGR do not contain provisions similar to those in the National Electricity Rules in respect of pass through, in light of the AER's previous decision for its electricity network, and an expectation that it would apply a similar approach, ActewAGL Distribution has instead included a self insurance allowance as an alternative, but inferior, means to acknowledge this risk. In the event that the AER does not accept this proposed allowance, or where the AER considers pass through to be acceptable to acknowledge this risk, ActewAGL Distribution proposes that its preferred position for a pass through event be included in the cost pass through tariff variation mechanism in its access arrangement. This pass through event would apply in the event

[154] *Utilities (Gas Restrictions) Regulation 2005*
[155] AER, *Draft Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 170

that insufficient gas is delivered to the ActewAGL Distribution gas network to fully meet the required demand as forecast in this access arrangement information, including interstate transmission or production plant failure or supply or demand constraints, or where a restriction scheme is introduced, and this event is outside the control of ActewAGL Distribution and impacts the revenue earning of the business relative to what would have earned had that gas supply been supplied as forecast, that this revenue foregone and any associated costs be subject to a pass-through event.

ActewAGL Distribution proposes that a supply curtailment event should be included in the access arrangement as follows:

> **Supply Curtailment Event** occurs when insufficient gas is transported to the ActewAGL Distribution gas network or is rationed to or within the ActewAGL Distribution gas network and cannot be supplied to meet normal demand requirements, as represented by the ActewAGL Distribution forecasts used to derive the Reference Tariffs in the Access Arrangement, and the event is outside the control of ActewAGL Distribution.

ActewAGL Distribution would be able to claim the full costs of foregone revenue that is directly attributable to this supply curtailment event, plus the costs of any customer claims and the increased costs imposed on it related to restoration of supply.

General pass through event

As noted above, in the AER's recent Final Decisions for ActewAGL Distribution's electricity distribution business and for the NSW electricity distribution businesses, the AER's preferred approach has been to include a *general nominated pass-through event*, in lieu of specific definitions of a 'major natural disaster event' and a 'force majeure event'.

The AER notes in its recent electricity network final decisions that it considers that the occurrence of major natural disaster events and force majeure events are possible, but there is no reason to consider that they are expected to occur. The AER therefore considered these events to be unforeseeable.

ActewAGL Distribution considers that the AER's definition of an 'unforeseeable event' captures both events that are difficult to define (because their precise nature is uncertain) and events that are able to be defined (where it is the occurrence of the event during the regulatory period that is uncertain, but the nature of the event is not uncertain). However, ActewAGL Distribution agrees with the AER's statement above that events which materially impact on a regulated business' ability to provide regulated services should not be precluded from pass through solely on the basis that it is not possible to define the event in advance of its occurrence.

In the light of the AER's articulation of its preferred approach to cost pass through in the recent electricity distribution decisions, ActewAGL Distribution has adopted the same approach in the access arrangement. That is, ActewAGL Distribution has proposed a 'general pass-through event' in lieu of defining specific 'major natural disaster', 'terrorism' and 'force majeure' events.

However, in adopting this approach ActewAGL Distribution notes that it has the potential to increase the risk faced by the regulated business, in that it does not make clear *a priori* what events will fall within the scope of a 'general cost pass through.' In order to reduce this risk, ActewAGL Distribution considers that the AER in its decision in relation to the access arrangement should make clear that events relating to natural disasters and terrorism would be expected to fall within this definition.

11.3.2.2 Cost pass through materiality threshold

As noted above, section 97(3) of the Rules 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".

ActewAGL Distribution proposes that most pass-through applications be considered as part of the annual tariff variation process (outlined further below), with tariffs varying once annually at the same time as the annual reference tariff variation formula mechanism, adjusting for CPI, UAG and the difference between forecast and actual amounts for specified charges, takes effect. This approach minimises administrative costs associated with cost pass through events for ActewAGL Distribution, the AER and users, as recognised by the AER in its Access Arrangement Guideline.[156] This is because it limits the number of tariff changes that parties face.

The AER's recent decision in respect of the ACT and NSW electricity distribution networks also provides some relevant guidance on appropriate materiality thresholds for *foreseeable* events:

> In some circumstances, however, the AER may determine that a lower materiality threshold is appropriate. [..]. In these circumstances [ie, costs associated with a specific nominated event], it is appropriate that a lower materiality threshold be adopted that represents the administrative costs of assessing such an application. [..].. The costs of assessing a cost pass through may, in certain circumstances be very low.[157]

For these *foreseeable* events that ActewAGL Distribution would have included the associated costs in its proposal in full if adequate information were available at the time of making its proposal. These include the application of new or changing obligations associated with the NECF, NGCF, STTM and the CPRS, including the potential for new gas fitting rules to apply in the ACT.

The two considerations outlined above suggest that a very low materiality threshold should apply to pass through events that are made as part of the annual tariff variation cycle. The administrative costs associated with these events are likely to be low, both to the extent that the events reflect foreseen events and that, in all cases, the process will occur at the same time as the annual tariff review, and so the impact on all parties is limited to one annual change. ActewAGL Distribution therefore considers that these pass through event applications should be subject to no explicit materiality threshold, recognising the minimal costs associated with considering these claims on ActewAGL Distribution, the AER and

156 Australian Energy Regulator, Access Arrangement Guideline, March 2009, p 78
157 AER, *Final Decision – Australian Capital Territory Distribution Determination 2009/10-20013/14*, April 2009, p. 130

users where these are considered as part of an annual tariff variation process. An implicit materiality threshold will apply to ActewAGL Distribution's decision to include a claim for pass through at the time of lodging its annual tariff variation notice, associated with the costs of preparing a detailed claim, which will limit claims of negligible value.

ActewAGL Distribution also notes that in the event that the AER does not approve the proposed specified charges factor in the annual tariff variation formula, then changes in UNFT, AEMC fees and the Energy Industry Levy considered under the cost pass through mechanism as a change in tax event should have a zero materiality threshold applied. Imposing a positive materiality threshold would prevent ActewAGL Distribution recovering its efficient costs in relation to those schemes.

ActewAGL Distribution considers that a different threshold should apply to pass through claims made outside of the annual tariff variation cycle. These claims will result in higher administrative costs, as they impose an additional change in tariffs on users. ActewAGL Distribution considers that a materiality threshold that reflects the administrative costs of consideration and application of these claims on ActewAGL Distribution, the AER and users should apply in these cases.

In this respect, ActewAGL Distribution proposes that an appropriate materiality threshold is $0.5 million (2009-10 dollars). That is, the effect of the cost pass through events must be such that the cost incurred, or forecast to be incurred, by ActewAGL Distribution as a result of the event must be at least $0.5 million above the costs approved in the access arrangement. This amount is consistent with the existing materiality threshold applying in ActewAGL Distribution's access arrangement in the earlier access arrangement period, and is considered to be greater than the expected administrative costs incurred by the AER in assessing the legitimacy of a proposed pass through event. This materiality threshold will therefore ensure that the proposed cost pass through mechanism complies with NER 97(3)(b), that is, that the possible effects of the mechanism on administrative costs of the AER, the service provider, and users or potential users, are considered.

11.3.3 Reference tariff variation process

This section sets out how the reference tariff variation mechanisms will operate, and the roles and responsibilities of relevant parties. As such, it provides information pursuant to Rule 97(4), requiring a reference tariff variation mechanism to "give the AER adequate oversight or powers of approval over variation of the reference tariff".

The mechanisms proposed by ActewAGL Distribution constitute a number of key stages that impose various respective roles and responsibilities on the AER and ActewAGL Distribution. In particular, this section identifies how the proposed cost pass through mechanism complies with the relevant requirements in the NGR.

11.3.3.1 ActewAGL Distribution notification of relevant reference tariff variation

Annual reference tariff variation formula mechanism

In applying the annual reference tariff variation formula mechanism, ActewAGL Distribution proposes to notify the AER of its tariffs for the coming year of the access arrangement 50 business days before the tariffs are expected to come into effect. This notification will include:

- The new reference tariffs to apply; and
- Information on how tariffs were calculated, including details of how tariffs have been varied in accordance with the formulae set out in the access arrangement.

The new tariffs will be calculated on the basis of the formulae set out in section 11.3.1.3 and so will include, as appropriate, an adjustment for changes in CPI, UAG, and externally imposed charges (as specified in the formula).

If ActewAGL Distribution does not intend to make an application for the pass through of costs as part of the annual tariff variation process for the relevant year, the notice will also provide a statement to this effect.

Cost pass through mechanism

ActewAGL Distribution considers it appropriate to, in most cases, provide for consideration of cost pass through claims as part of the annual tariff variation process. This approach minimises administrative costs for ActewAGL Distribution and the AER in considering cost pass through claims, as well as the costs of retailers and other users arising from tariff changes occurring more frequently than once annually.

ActewAGL Distribution notes that this approach is consistent with that suggested in the AER Access Arrangement Guideline:

> To assist users and prospective users as well as lower administrative costs…, where possible the timing of cost pass through applications should be considered together with any other proposed periodic (annual) changes to tariffs arising from other tariff variation mechanisms in an approved access arrangement.[158]

ActewAGL Distribution therefore proposes that in the majority of instances, if a relevant pass through event occurs, it will make an application to the AER for the pass through of costs at the same time as its notification of tariffs under the annual reference tariff variation formula mechanism. These need not relate to the immediately preceding year. This approach recognises that a relevant event may occur close to or after the submission of an annual tariff variation statement to the AER (outlined below), making it difficult to calculate relevant costs in time for inclusion in that statement, while also providing the AER with adequate time to consider claims.

Recognising that there may be a significant delay between ActewAGL Distribution facing changes in costs as a result of a pass through event, and their reflection in tariffs, ActewAGL Distribution proposes that pass through amounts include symmetrical compensation for the time value of money.

There is also the potential for some pass through events to have a financial impact that requires costs to be reflected in prices as soon as possible, rather than waiting for the annual tariff variation process. ActewAGL Distribution considers this to be an exceptional

[158] Australian Energy Regulator *Access Arrangement Guideline*, March 2009, p 78

circumstance that may only arise as a result of events that lead to very high costs on the business. Without timely compensation, these costs may undermine ActewAGL Distribution's ability to provide the reference services.

The access arrangement therefore also includes scope for ActewAGL Distribution to make a pass through event application at any time, with the consent of the AER. This consent cannot be reasonable withheld. ActewAGL Distribution also proposes that a different materiality threshold would apply to such events, recognising the administrative costs of such a claim on ActewAGL Distribution, the AER, and users, as discussed in section 11.3.2.2.

When ActewAGL Distribution considers that a relevant pass through event has occurred for which it is appropriate to seek the pass through of costs (that is, the costs are material), either as part of the annual tariff variation cycle or as a stand alone application, ActewAGL Distribution will provide the AER with the following information in a statement:

- details of the relevant pass through event concerned;
- the date the relevant pass through event took or will take effect;
- the applicable reference tariffs that currently apply;
- the estimated financial effect of the relevant pass through event on ActewAGL Distribution, and how that financial effect has resulted in a variation to the relevant reference tariffs;
- the pass through amount or change in reference tariffs ActewAGL Distribution proposes in relation to the relevant pass through event;
- the basis on which the pass through amount or change in reference tariffs is to apply;
- how the pass through amount or change in reference tariff complies with the pass through mechanism;
- the date from and period over which ActewAGL Distribution proposes to charge the pass through amount or change the Reference Tariffs; and
- if applicable, how ActewAGL Distribution proposes to allocate the pass through amount over that period, and between users, and the price or charging structure that ActewAGL Distribution proposes to use to recover the pass through amount from users (being the basis on which ActewAGL Distribution proposes the pass through amount is to apply).

Where provided as part of the annual tariff variation cycle, this statement will be provided to the AER at least 50 business days before the start of the next financial year, to allow relevant pass through amounts to be incorporated into tariffs as part of the annual tariff variation process.

11.3.3.2 AER assessment and decision on proposed variation of reference tariffs

This stage of the process for processing a proposed cost pass through event demonstrates that the proposed cost pass through mechanism complies with NGR 97(4) which states that “a reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff”.

Annual reference tariff variation formula mechanism

Upon receipt of a notification from ActewAGL Distribution regarding the application of annual reference tariff variation formula, the AER must notify ActewAGL Distribution of its confirmation in respect of the correct application of the relevant formulae, or any revisions it may require.

ActewAGL Distribution proposes that the AER confirm ActewAGL Distribution’s calculations not later than 20 business days before the tariffs are scheduled to change. This timing allows ActewAGL Distribution to prepare and publish tariffs in accordance with the decision at least 10 business days before they come into effect, and for retailers to reflect those prices in tariffs as part of an orderly annual tariff change at the start of each financial year.

Cost pass through event mechanism

Upon receipt of a statement from ActewAGL Distribution to increase or decrease reference tariffs in accordance with the cost pass through event mechanism, the AER must notify ActewAGL Distribution in writing of its decisions in respect to:

- whether the notification relates to a relevant cost pass-through event;
- the pass through amount change in Reference Tariffs; and
- the basis on which any pass through amount is to apply.

Where an application for pass through of costs is made outside of the annual tariff variation cycle, ActewAGL Distribution considers that the AER should also include a decision on ActewAGL Distribution’s proposed date for the tariff variation to take effect.

In taking these decisions, the AER must ensure that the financial effect on ActewAGL Distribution associated with the relevant pass through event concerned is economically neutral taking into account:

- the relative amounts of reference services supplied to each user;
- the time cost of money for the period over which the pass through amount is to apply, including any delay in the recovery of a pass through amount associated with recovery of costs inline with the annual tariff variation cycle;
- the manner in which and period over which the pass through amount or change in reference tariffs is to apply;
- the financial effect to ActewAGL Distribution associated with the provision of reference services directly attributable to the relevant pass through event concerned, and the time at which the financial effect arises;
- if the relevant pass through event is a change in taxes event, the amount of any change in another tax which, in the AER’s opinion, may have been introduced as complementary to or may substitute for the change in taxes event concerned;

- the effect of any other previous relevant pass through event since the last decision made in respect of a cost pass-through event under clause 6.10 of the access arrangement;
- any pass through amount applied relating to a previous relevant pass through event which resulted in ActewAGL Distribution recovering an amount either more or less than the estimated financial effect on ActewAGL Distribution of that previous relevant pass through event; and
- any other factors the AER considers relevant.

As outlined above, ActewAGL Distribution proposes that the AER make its decision not later than 20 business days before the tariffs are scheduled to change, to allow the preparation and publication of tariffs before 1 July each year.

11.3.3.3 Variation of reference tariffs

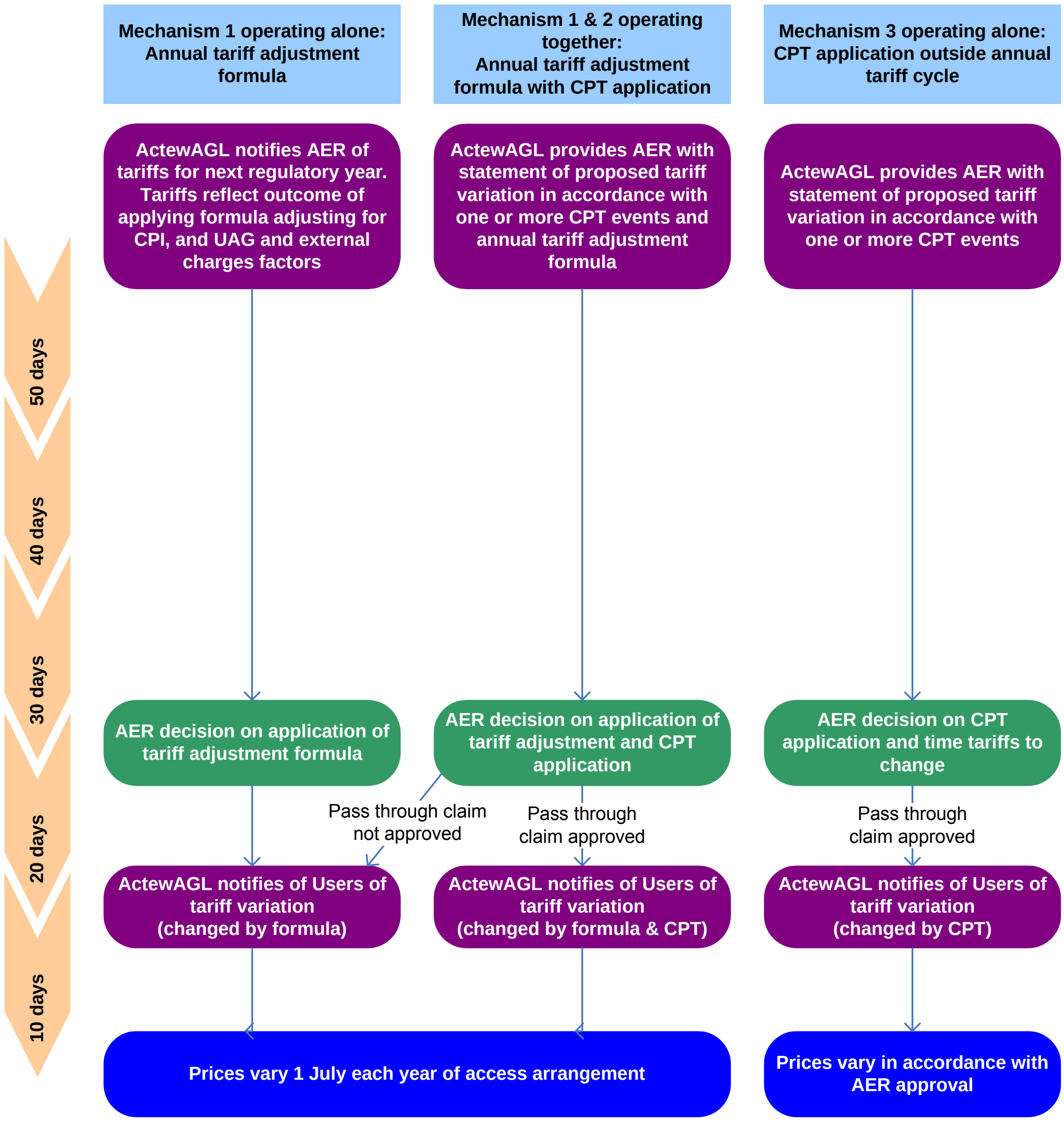
The new tariffs (as approved by the AER) will come into effect on 1 July each year of the access arrangement.

In line with the tariff variation mechanism in the earlier access arrangement, where the AER does not make a decision in the required time on a proposed tariff variation, tariffs will change automatically vary in accordance with ActewAGL Distribution's notification (including the application of the adjustment formula and any relevant cost pass through amounts) on the date stated in ActewAGL Distribution's notification. If the AER subsequently decides against all or part of the variation of tariffs, it may require ActewAGL Distribution to amend tariffs in the following year to take account its decision. The adjustment to tariffs in the following year should leave ActewAGL economically neutral compared with a situation in which the AER's decision had been implemented at the time of the earlier tariff variation.

In addition, ActewAGL Distribution *must*, after receipt of a notice as to a negative pass through amount apply the negative pass through amount on the basis decided by the AER.

These arrangements are illustrated at a high level in Figure 11.1.

Figure 11.1 Proposed reference tariff variation mechanism notification and approval process



11.3.4 Conclusion

In summary, ActewAGL Distribution considers that the proposed reference tariff variation mechanisms:

- are compliant with section 97 of the NGR;
- build on ActewAGL Distribution's current tariff variation mechanism by providing greater clarity over the tariff variation process;
- will enhance the consistency of cost pass through regulatory arrangements across similar businesses and jurisdictions;

- draw on the lessons and experiences of the most recent and relevant regulatory reviews undertaken in Australia namely, the ESC’s Access Arrangement Review, and the NSW and ACT Electricity Distribution Reviews; and
- will build on ActewAGL Distribution’s cost pass through arrangements in the earlier access arrangement period so as to ensure that the business is not unduly exposed to exogenous risk and that customers do not face inappropriately high reference tariffs.

12 Changes to the access arrangement

The chapter of the access arrangement information summarises proposed revisions to the access arrangement.

ActewAGL Distribution is proposing to substantially retain its access arrangement from the earlier access arrangement period. Terms and conditions of access to the network remain largely unaltered and changes mostly reflect changed requirements from those of the former Gas Code to those of the NGL and NGR. The reference tariff structure applying in the earlier access arrangement period has been retained.

Some changes are proposed to the tariff variation mechanism (in relation to cost pass through and an adjustment mechanism for unaccounted for gas and fees, taxes and levies), to ensure that the impacts of ongoing developments in the regulatory framework and gas market can be appropriately managed. These have been discussed in detail at section 11 of this access arrangement information.

12.1 Revisions to Part 1—Introduction

Part 1 of the access arrangement has been amended to refer to the NGR as the governing legislation rather than the Gas Code.

ActewAGL Distribution has selected to submit revisions to the access arrangement 4 years after this access arrangement takes effect. It is intended that those revisions will take effect 5 years after this access arrangement takes effect. These dates reflect the “general rule” stated at Rule 50 of the NGR.

References to “Greater Queanbeyan” now refer to “Queanbeyan”. This reflects the proclamation of “Queanbeyan City” council in place of “Greater Queanbeyan City” council on 17 December 2004. References to Palerang have been included with respect to the extension of the network to Bungendore in the Shire of Palerang during the earlier access arrangement period.

12.2 Revisions to Part 2—Services policy

No significant amendment is proposed for this part of the access arrangement.

12.3 Revisions to Part 3—General terms and conditions for access

Part 3 of the Access Arrangement has been updated to reflect the change from the National Gas Code to the NGL/NGR. For example, the access arrangement now refers to “Access Determinations” in place of “arbitrated access decisions”, reflecting Chapter 6 of the NGL. No other significant amendments have been made.

ActewAGL Distribution has clarified the position with respect to title to gas in clause 3.41, as this is important for some aspects of the proposed CPRS. However, this does not represent a change to the position under the current access arrangement, merely a confirmation of that position.

ActewAGL Distribution submits that these terms and conditions of access are reasonable, and in particular seek to impose a reasonable risk allocation between ActewAGL Distribution and Users. As the result of consultations with Users and the ICRC in the before approval of the access arrangement in the earlier access arrangement period, the terms and conditions were substantially re-written to put them into a plain English style that is more readily understood by Users.

ActewAGL considers that the terms have worked well over the term of the earlier access arrangement, with Users who have negotiated Transport Agreements for access to the network not seeking significant change to the terms.

12.4 Revisions to Part 4—Reference tariff policy

Part 4 of the access arrangement has been amended to:

- refer to the building block approach (in respect of calculating the Capital Base);
- refer to “new capital expenditure” in place of “new facilities investment” to reflect the NGL/NGR;
- specify a new incentive mechanism to encourage efficiency, discussed in section 10.6.2 of this access arrangement information; and
- include new fixed principles to reflect changes to the incentive mechanism.

12.5 Revisions to Part 5—Reference tariffs

Part 5 of the access arrangement has been amended to reflect applicable dates and updated references to the NGR.

12.6 Revisions to Part 6—Variations to reference tariffs

As mentioned above, ActewAGL Distribution is proposing changes to the tariff variation mechanism (in relation to cost pass through and an annual tariff variation formula, to ensure that the impacts of ongoing developments in the regulatory framework and gas market can be appropriately managed. These have been discussed in detail at section 11 of this access arrangement information.

12.7 Revisions to Part 7—Extensions and expansions policy

No significant amendment is proposed for this part of the access arrangement.

12.8 Revisions to Part 8—Trading policy

This section of the access arrangement has been updated to refer to the NGR. In particular:

- Clause 8.1 has been added to clarify that capacity trading is done through the Gas Market Business Rules;
- Clause 8.3 has been amended to reflect that it is the transferor who now has to give the service provider notice; and
- The NGR do not refer to the concept of a “bare transfer”, although a similar concept is described in Rule 105(2). ActewAGL Distribution has addressed this change by retaining the definition of bare transfer, but updating that definition to refer to the equivalent provision in the NGR.

12.9 Revisions to Part 9—Queuing policy

ActewAGL Distribution has amended Part 9 of the access arrangement to refer to an “Access Determination” in place of an “arbitrated access decision”. In other respects, the queuing policy is consistent with the NGR, as it provides a mechanism to treat prospective users on a fair and equal basis (NGR 103(3)). As required by Rule 103, it also allows users to understand:

- the basis of priority; and
- their position in the queue.

12.10 Revisions to Part 10—Capacity management policy

Section 3.7 of the Gas Code used to require an access arrangement to include a statement on whether the Covered Pipeline is a Contract Carriage Pipeline or Market Carriage Pipeline. The equivalent provision in the NGR (Rule 105) contains no such obligation. Accordingly, this section is no longer required and has been removed.

12.11 Revisions to access arrangement attachments

Attachment 2—*Requests for service* has been amended for minor changes in section 112 of the NGR.

13 Key Performance Indicators

This chapter of the access arrangement information addresses the requirement to include Key Performance Indicators in the access arrangement information.

13.1 Relevant requirements

There is limited guidance provided in the NGR as to the appropriate scope of Key Performance Indicators (KPIs). Rule 72(1)(f) requires the access arrangement information to include “the key performance indicators to be used by the service provider to support expenditure to be incurred over the access arrangement period”. The AER’s *AA Guideline* states:

> The NGR does not specify any particular KPIs that should be included in the access arrangement information as they will be specific to the type of pipeline and access arrangement… A range of financial, technical and user/customer KPIs may also be included in the access arrangement information.[159]

13.2 Proposed Key Performance Indicators

ActewAGL Distribution has selected 21 KPIs that it considers are reflective of performance level for the network and are key drivers for capital and operating expenditure. These indicators can be categorised on basis of objective and activity type, and reflect the maintenance and response procedures for the assets. ActewAGL Distribution has also selected a mixture of input and outcome KPIs, showing the drivers of expenditure (inputs, such as preventative maintenance) and performance (outcomes, such as reliability or utilisation). The KPIs, and their definitions, are set out in Table 13.1. This table also includes information on how the KPIs drive capital and operating expenditure.

[159] Australian Energy Regulator, *Access Arrangement Guideline*, March 2009, pp 70-1

Table 13.1 ActewAGL Distribution Key Performance Indicators

Indicator	Definition
Supply reliability	
Major unplanned outages ≥5 customers	The number of unplanned supply outage incidents that impact 5 or more customers. Performance under this indicator reflects the adequacy of the design of the network. Performance under this measure is mostly driven by third party hits to the network, and so is linked to performance under the “hits to network” indicator.
Asset integrity	
Third Party Reported Gas Leaks per 10 kilometre of main	The frequency of gas leaks reported by parties external to the distributor per each 10 kilometre of main. These are usually very minor reports such as the smell of gas. Performance under this indicator is mostly driven by leaks at customer metering equipment and drives metering equipment replacement capital expenditure and maintenance expenditure.
Hits to Network per 10 kilometre of main	The number of mechanical damage incidents per 10 kilometre of main. These incidents may have serious consequences in regard to supply reliability, safety and the environment. Minimising this measure has a direct impact on unplanned maintenance and it therefore a significant driver of operating costs, for example UAG and gas losses.
% Unaccounted for Gas	The proportion of gas measured as being received into the network that is not measured as being delivered. This is direct driver of network operating expenditure.
Emergency management	
% Emergency Response within 60 minutes	The annual percentage of times that responses to emergency incidents have been inside 60 minutes. This is an important indicator of responsiveness to emergency incidents. ACTPLA uses this measure to determine emergency responsiveness in accordance with regulatory obligations. This indicator also provides a measure to assist understanding of factors that influence response times and the ability to deliver outcomes that exceed regulatory compliance and mitigate network and community risks.
Preventative Maintenance (PM) Completion	The level of PM work completed within the 12 month period, as a percentage of all PM of scheduled for completion with the year. PM extends the life of assets and ensures operational effectiveness and efficiency, thereby influencing stay in business capital expenditure and network reliability. It also contributes to safety outcomes as PM can identify asset integrity issues that may lead to safety issues before they occur.
PM/CM Ratio	The number of PM service orders completed during the year, compared with the number of Corrective Maintenance (CM) service orders as a percentage. A high level of CM may highlight specific problems within a system that may be used to identify poorly performing assets, or a change in asset risk profiles, driving the need for capital improvements.
Pipeline Patrol Compliance	Tracks whether the several types of pipeline patrol with different frequencies are being completed on schedule. This can be used to determine the adequacy of current resource levels, particularly with regard to standby resources and third party contractor management.

Indicator	Definition
Simulations Conducted	Number of emergency simulations conducted each year. Simulations of incidents and emergency exercises are conducted at regular intervals to confirm the adequacy of resources and robustness of emergency response management systems. Rotating simulations across regions and asset classes ensures that staff emergency training is maintained.
Utilisation	
Customers per kilometre Mains	The customers connected per kilometre of the mains laid. This indicator shows the utilisation of infrastructure as a lead indicator for load and capacity planning for capacity development and stay in business capital expenditure, together with network marketing strategies.
Network Performance	
Cathodic Protection Reliability	The percentage the level of cathodic protection in the network. Cathodic protection is an important indicator for the protection of key high pressure assets to ensure maintenance (and extension) to asset lives.
SAIFI per 1000 customers	System average interruption frequency index (SAIFI) is the ratio of total number of events to the total number of customers, expressed per 1000 customers. This is an important indicator of network performance and system reliability.
Back Office/ Market interface	
Contract Billing	The timeliness of monthly read of daily read sites as a percentage. This shows customer billing management performance, allowing network revenue management and customer service levels to be maintained.
Quarterly and Monthly Tariff Reading	The percentage of quarterly and monthly meter reading completed within ±2 days of the scheduled date. This shows customer billing management performance, allowing network revenue management and customer service levels to be maintained.
Service Order Delivery	The provision of the requested service within the specified timeframe for the activity. This shows that customer and retailer service level obligations are met in line with regulatory requirements.
Health and safety	
Lost Time Injury: JAM	Lost Time Injury (LTI) to JAM employees. ActewAGL Distribution has obligations under the *Work Safety Act 2008* (ACT) to ensure the safety of its employees, including contractors. This indicator assists in monitoring the safety performance of JAM. LTIs are also a driver of costs.
Lost Time Injury: Contractors	This keeps account of LTIs of contractors to JAM. ActewAGL Distribution has obligations to sub-contractors as well as direct employees under the Work Safety Act.
Environment	
Reportable Environment Incidents	The number of times ActewAGL Distribution is directly involved in an environmental incident with requires external reporting to the EPA (NSW) or Environment ACT. Environmental incidents are costly and damage ActewAGL Distribution's reputation. Minimisation of this measure, through appropriate environment management plans, practices and procedures is a key driver of expenditure.
Safety and Operating Plan	

Indicator	Definition
Non-Conformance Report not actioned	Percentage of SAOP non-conformance reports (NCRs) that are followed up within the required timeframe. This is a measure of compliance with the SAOP. This includes application and compliance with relevant Australian Standards, which are called up in the SAOP and management of distribution authorisation and licence obligations.
Customer service	
New Customer Connections on time	Percentage of new customer connections made on time. This is a measure of customer service, as well as relating to a Consumer Protection Code Minimum Service Standard rebate. This is also a key driver of ActewAGL Distribution revenue, as late connections lead to foregone revenue.
Consumer Protection Code Compliance	Compliance with the Consumer Protection Code. The Code outlines the basic rights of customers and consumers and utilities with respect to access to, and provision of, utility services. Compliance with the Code is a key obligation on ActewAGL Distribution.

The KPIs in Table 13.1 can be linked directly to outcomes in the various asset management, safety and environmental plans in place for the ActewAGL Distribution gas network. As asset management contractor, JAM is directly accountable for its performance against the majority of these KPIs, and is subject to penalties under the contract for underperformance. Past performance against proposed KPIs, and targets for the access arrangement period, are provided in Table 13.2.

Table 13.2 ActewAGL Distribution KPI performance and targets

Indicator	2005*^	2006*	2007*	2008*	2009†	2010 target	2010-15 target
Major Unplanned Outages ≥ 5 customers	0	3	3	0	4	2	2
Third party reported gas leaks per 10km mains	3.3	3.0	2.5	2.4	3.3	3	3
Hits to Network per 10km mains	0.60	0.56	0.57	0.65	0.66	0.7	0.7
Unaccounted For Gas (%)	1.11	1.66	1.47	1.61	1.70	1.70	1.80
Emergency Response within 60 minutes (%)	100	100	100	100	100	100	100
PM Completion	100	100	100	100	100	100	100
PM / CM Ratio (%)	50	49	50	57	50	50	50
Pipeline Patrol Compliance (%)	96	100	100	100	100	100	100
Simulations conducted	0	0	1	2	2	2	2
Utilisation: customers per km mains	23	24.5	25	25.2	25	25	25
Cathodic Protection reliability	Not available		100	90	100	100	100
SAIFI - per 1000 customers	1.24	1.51	1.35	1.24	0.93	<10	<10
Contract Billing-Monthly read of the Daily Read Sites (%)	100	99	100	100	100	98	98
Tariff Reading Quarterly/ Monthly/MDL within ±2 of the scheduled read date (%)	100	99	99	99	100	95	95
Service Order delivery within the specified timeframe of the activity (%)	99	100	100	100	100	100	100
LTI:AAM	0	0	0	0	0	<5	<5
LTI: Contractors	1	0	0	0	0	<5	<5
Reportable environmental incidents	0	0	0	0	0	0	0
NCR not actioned	1	0	0	0	0	0	0
New Customer Connections on time (%)	98.70	98.60	100	99.80	100	100	100
Consumer Protection Code Compliance (%)	100	100	100	100	100	100	100

* Year ending June.
^ All values are for performance on the ACT and Queanbeyan network, with the exception of pipeline patrol compliance and utilisation, which are values and targets for the ACT network only.
† Values are for June 08 to May 09.

The targets set out in Table 13.2 have been set with reference to average past performance, and outcomes expected from the level of expenditure included in the access arrangement period. Reductions in forecast capital and/or operating expenditure would be expected to influence performance under these KPIs, and may drive the need to change targets.

Attachments

A Abbreviations used in the access arrangement information

Table A.1 Abbreviations used in the access arrangement and access arrangement information

Abbreviation	*Meaning*
AA	access arrangement
ABN	Australian Business Number
ACN	Australian Company Number
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
ACTEW	ACTEW Corporation Ltd
ACTHERS	ACT House Energy Rating Scheme
ACTPLA	ACT Planning and Land Authority
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	The Australian Gas Light Company
AMP	Asset Management Plan
APT	Australian Pipeline Trust
AS	Australian Standard
ASIC	Australian Securities and Investment Commission
ASR	Additional Services Request
ASX	Australian Stock Exchange
BCA	Building Code of Australia
capex	capital expenditure
CAPM	Capital Asset Pricing Model
CAR	Client Acceptance Report
CEG	Competition Economics Group
CGS	Commonwealth Government Securities
CM	Corrective Maintenance
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
Cth	Commonwealth
CTS	custody transfer station
DAMS	Distribution Asset Management Services Agreement
DGM	Dividend Growth Market
DWE	NSW Department of Water and Energy
E to G	electricity to gas conversions

Abbreviation	Meaning
EA	Enterprise Agreement
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
EBT	earnings before tax
EEH	energy efficient homes
EER	energy efficiency rating
EGP	Eastern Gas Pipeline
EGW	electricity, gas and water
EPA	NSW Environmental Protection Authority
ERL	Energy Rating Labelling
ESC	Victorian Essential Services Commission
FPSC	fixed price service charge
GDP	Gross Domestic Product
GIS	geographic information system
GJ	Gigajoule(s)
GMC	Gas Market Company
GSP	Gross State Product
HDD	heating degree day
HFL	Hoskinstown to Fyshwick Loop
HP	high pressure
I&C	industrial and commercial
ICRC	Independent Competition and Regulatory Commission
IT	Information Technology
JAM	Jemena Asset Management Pty Ltd
km	kilometre(s)
kPa	kilopascal(s)
KPI	Key Performance Indicator
LGA	local government area
LP	low pressure
LTI	Lost Time Injury
m	metre(s)
MAOP	maximum allowable operating pressure
MCE	Ministerial Council on Energy
MDQ	maximum daily quantity
MEPS	Mandatory Energy Performance Standards
mm	millimetre(s)
MP	medium pressure

Abbreviation	Meaning
MRET	Mandatory Renewable Energy Target
MRP	Market Risk Premium
MSP	Moomba to Sydney Pipeline
na	not applicable
NCR	Non Conformance Report
NECF	National Energy Customer Framework
NEMMCO	National Energy Market Management Company
NERA	NERA Economic Consulting
NGCF	National Gas Connections Framework
NGERS	National Greenhouse Emissions Reporting Scheme
NGL	National Gas Law
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research (also known as National Economics)
NSW	New South Wales
NTER	National Tax Equivalent Regime
OH&S	Occupational Health and Safety
opex	operating and maintenance expenditure
PM	Preventative Maintenance
POTS	Package offtake station
PRS	primary regulating station
PTRM	post tax revenue model
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
RET	Renewable Energy Target
RFM	roll forward model
RIN	Regulatory Information Notice
RUGS	Request Utility for Gas Service
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAOP	Safety and Operating Plan
SCADA	supervisory control and data acquisition
scmh	standard cubic metres per hour
SCO	MCE Standing Committee of Officials
SDRS	secondary district regulator set
SRS	secondary regulator set
STTM	Short Term Trading Market

Abbreviation	Meaning
T&C	terms and conditions
TAB	taxation asset base
TJ	Terajoule(s)
TP	Transitional Provision
TRS	trunk receiving station
TWAW	Thanks Water Act Water
UAG	unaccounted-for gas
UNFT	Utilities Network Facilities Tax
WACC	weighted average cost of capital
WBH	Water Bath Heater
WELS	Water Efficiency Labelling and Standards
WTP	willingness to pay

B Information required by the Regulatory Information Notice

B.1 Index of information

The Regulatory Information Notice (RIN) served on ActewAGL Distribution on 11 May 2009 specifies that:[160]

> As the AER is not mandating the form and manner of all information that is required to be provided in this Notice (including that is to be provided in the pro formas) to demonstrate compliance with this Notice the service provider must provide an index or list of where the information and documentation required to be provided in the Notice is included in the access arrangement proposal submission.

Table B.1 forms such a list including, where applicable, the location within ActewAGL Distribution's access arrangement proposal submission of the required information. .

Table B.1 Location in the submission of information required by Regulatory Information Notice

RIN reference			Access arrangement information reference	Access arrangement proposal reference
2.1 Service provider details and business context				
2.1.1		**Details of service providers**		
	(a)	Trading name	Section 2.1	
	(b)	Australian Company Number	Section 2.1	
	(c)	Type of service provider (owner, controller or operator)	Section 2.1	
	(d)	Type of legal entity	Section 2.1	
2.1.2		**Local agent of a service provider**		
		Provide a statement that the service provider in 2.1.1 is not a local agent of a service provider of the pipeline.	Section 2.1	
2.1.3		**Service provider acting on behalf of other service providers**		
		Provide a statement that the service provider in 2.1.1 is not acting on behalf of another service provider of the pipeline.	Section 2.1	
2.1.4		**Associate contracts providing goods and services**		
For each associate contract relevant to the delivery of pipeline services:				
	(a)	The name of the associate contract	Section 9.5, Attachment P	
	(b)	The name of all parties to the associate contract	Section 9.5, Attachment P	

[160] Regulatory Information Notice under Section 48(1) of the NGL, section 1.6.2.

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(c)	An outline of the nature of goods or services provided by or obtained from the associate contract	Section 9.5, Attachment P	
(d)	An outline of the relationship of the party or parties to the associate contract to each service provider of the pipeline	Section 9.5, Attachment P	
2.2 Background to the pipeline			
2.2.1	**Pipeline and pipeline services**		
(a)	Identify the pipeline to which the access arrangement relates and include a reference to a website at which a description of the pipeline can be inspected	Section 2.3	Part 1
(b)	Describe the pipeline services the service provider proposes to offer to provide by means of the pipeline	Section 11.1	Part 2
(c)	Specify the reference services identified in the response to 2.2.1(b)	Section 11.1	Part 2
(d)	Outline and explain how the proposed reference services are those that are sought by a significant part of the market	Section 11.1	
2.2.2	**Demand**		
(a)	Demand		
	Minimum, maximum and average demand for the earlier access arrangement period	Section 5.1	
	Forecast maximum and average demand and customer numbers for the access arrangement period	Section 5.2	
(b)	Volumes		
	Actual and estimated volumes for the earlier access arrangement period	Section 5.1	
	Forecast volumes for the access arrangement period by tariff class and pipeline service	Section 5.2	
(c)	Customer numbers		
	Actual and estimated customer numbers for the earlier access arrangement period	Section 5.1	
	Forecast customer numbers for the access arrangement period by tariff class and pipeline service	Section 5.2	
(d)	Details of the key driver behind the demand forecasts	Section 5.2.3	
(e)	The methodology that has been used to support the demand forecasts, including the key assumptions and inputs that have been used and how demand for pipeline services is differentiated	Section 5.2 Attachment G	
(f)	An explanation of how the volume only forecasts have been used to develop the service provider's capital expenditure and operating expenditure forecasts	Section 5.2.5.1	
(g)	An explanation of any trends of demand and volumes over the earlier access arrangement period and the access arrangement period	Section 5.2 Attachment G	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.2.3	**Pipeline capacity and utilisation**		
	To the extent that it is practicable to forecast pipeline capacity and utilisation of pipeline capital over the access arrangement period, a forecast of pipeline capacity and utilisation of pipeline capacity over that period and the basis on which the forecast has been derived.		
2.3 Building block revenue			
2.3.1 Return on the projected capital base			
2.3.1.1	**Opening capital base at the beginning of the earlier access arrangement period**		
(a)	The opening capital base by asset class at 1 July 2003 and 1 July 2004	Section 7.2.1	
(b)	The capital base approved by the jurisdictional regulator as at 1 July 2003 and 1 July 2004	Section 7.2.1	
(c)	remaining asset lives that reflect the capital base as at 1 July 2004 and the asset lives that reflect the capital base as approved by the jurisdictional regulator as at 30 June 2004	Section 7.2.1	
(d)	a reconciliation of the opening capital base in 2.3.1.1(a) and 2.3.1.1(b). Include in that reconciliation adjustments for any difference in estimated and actual capital expenditure and other adjustments made to the opening capital base as at 1 July 2004 and explain these variations	Section 7.2.1	
(e)	a reconciliation of any changes in asset classes between the earlier access arrangement period and the access arrangement period	Section 7.2.1	
2.3.1.2	**Capital expenditure in the earlier access arrangement period**		
(a)	An explanation for:		
	i. Any significant variations between capital expenditure approved by the jurisdictional regulator and the actual and/or estimate capital expenditure for the earlier access arrangement period	Section 6.1	
	ii. How conforming capital expenditure added to the capital base in the earlier access arrangement period meets the code requirements	Section 6.1	
(b)	By asset class for each year of the earlier access arrangement period		
	i. Amounts added to the opening capital base for conforming capital expenditure	Section 6.1.5 RFM	
	ii. Amounts for non conforming capital expenditure identified as recovered by surcharge, added to a speculative capital expenditure account (under the code the speculative investment fund) amounts, other amounts of non conforming capital expenditure	Section 6.1.5	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.3.1.3	**Capital contributions, speculative capital expenditure account (under the code speculative investment fund), reused assets, redundant assets, disposals in the earlier access arrangement period**		
By asset class for each year of the earlier access arrangement period:			
(a)	Amounts added to the opening capital base for capital contributions	Section 6.2.3.1	
(b)	Amounts added to the opening capital base from the speculative capital expenditure account (under the code the speculative investment fund)	Section 7.1.3	
(c)	Amounts added to the opening capital base for the reuse of redundant assets	Section 7.1.3	
(d)	Amounts deducted from the opening capital base for redundant assets	Section 7.1.3	
(e)	Amounts deducted from the opening capital base for disposals	Section 7.1.3	
(f)	Explanation for how amounts added to the opening capital base from the speculative capital expenditure account (under the code the speculative investment fund) meet the relevant code criteria	Section 7.1.3	
(g)	Explanation for how amounts added to the opening capital base for the reuse of redundant assets meet the relevant code criteria	Section 7.1.3	
2.3.1.4	**Depreciation in the earlier access arrangement period**		
(a)	For each year of the earlier access arrangement period, for each asset class amounts deducted from the opening capital base for depreciation, including amounts of depreciation for changes to the capital base in the earlier access arrangement period. Depreciation for the earlier access arrangement period should account for and distinguish depreciation referable to the opening capital base and amounts added to, or deducted from, the opening capital base for reused redundant assets, redundant assets, disposals, conforming capital expenditure, capital contributions included in the capital base and amounts from the speculative capital expenditure account (under the code the speculative investment fund)	Section 7.1.4 RFM	
(b)	For each year of the earlier access arrangement period, asset lives of each asset	Section 7.1.4 RFM	
2.3.1.5	**Rate of inflation and adjustment to the capital base in the earlier access arrangement period**		
(a)	The actual or estimated rates of inflation used to adjust the capital base for inflation over the earlier access arrangement period	Section 7.1.5 RFM	
(b)	The adjustments to the capital base for inflation over the earlier access arrangement period	Section 7.1.5 RFM	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.3.1.6	**Capital base in the earlier access arrangement period**		
	The capital base by asset class for each year of the earlier access arrangement period	Section 7.1.2 RFM	
2.3.1.7	**Forecast conforming capital expenditure in the access arrangement period**		
(a)	Amounts by asset class for each year of the access arrangement period for forecast conforming capital expenditure	Section 6.2.1	
(b)	The extrapolation rates, where applicable, used in deriving forecast conforming capital expenditure	Section 6.2.1.1 Section 8.2	
(c)	The nature of forecast conforming capital expenditure projects or programmes material to an asset class including a brief description of the capital expenditure and the location on the distribution pipeline or network. And define the materiality threshold used.	Section 6.2.2	
(d)	Any assumptions used in deriving the forecast conforming capital expenditure These may include: the unit rates used for key items of expenditure, how these have been developed (including source material) and evidence that they reflect efficient costs; specific rates used to derive or extrapolate expenditure estimates (for example, labour and materials). Where relevant provide: the specific rate used in each year of the access arrangement period; whether the rate is in real or nominal terms; how the derivation or extrapolation has been developed (including source material).	Section 6.2.1.1	
(e)	Any relevant internal decision making documents including but not limited to business cases, feasibility studies, forecast demand studies and internal reports and the date of board resolution/management decisions relating to approval of the forecast capital expenditure. Any other internal or external documentation or models to justify the forecast conforming capital expenditure	Section 3.4 Attachment H	
(f)	Details as to whether the forecast conforming capital expenditure is to be funded by parties other than the asset owner and details of contractual agreements with parties where capital contributions are made by users to new capital expenditure as subject to Rule 82	Section 3.2.2.3 Section 6.2.3.1	
(g)	An explanation of how the forecast capital expenditure conforms with the criteria under Rule 79(1)	Chapter 3 Section 6.2.1.1	
(h)	The reason why the forecast capital expenditure is justifiable under Rule 79(2). In explaining why the forecast capital expenditure is justifiable outlining, which sub rule in 79(2) is relied on	Section 6.2.2	
If Rule 79(2)(a) is relied on to justify new capital expenditure:			

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(i)	An explanation and the quantitative analysis which demonstrates how the capital expenditure is justifiable under Rule 79(2)(a)	Section 6.2.2	
(j)	An outline of the nature and quantification of the economic value that directly accrues to the service provider, gas producer, users and end users to address Rule 79(3)	Not applicable	
If Rule 79(2)(b) is relied on to justify new capital expenditure provide in the access arrangement proposal submission:			
(k)	An explanation of how the capital expenditure is justifiable under Rule 79(2)(b). The explanation (including relevant information and documentation) will need to outline: i. The incremental service or services with reference also to Rule 79(4)(a) ii. The incremental revenue, with reference to the derivation of incremental revenue in Rule 79(4)(b) iii. The incremental expenditure with reference to Rule 79(4)(b) iv. Quantitative analysis that demonstrates the capital expenditure is justifiable under Rule 79(2)(b), showing: The present value of expected incremental revenue and how it is determined consistent with Rules 79(4)(a) and 79(4)(b) The discount rate that is used to determine the present value is equal to the rate of return implicit in the reference tariff The present value of the expected incremental Expenditure	Section 3.2.2 Attachment H Attachment Q.4	
If Rule 79(2)(c)(i)-79(2)(c)(iii) is relied on to justify new capital expenditure provide in the access arrangement proposal submission:			
(l)	The relevant statutory obligation or technical requirement and the relevant authority or body enforcing the obligation or requirement (m) An explanation of how the forecast capital expenditure satisfies the relevant statutory obligation or technical requirement	Section 3.2.2 Chapter 4	
(n)	Supporting technical or other external or internal reports about how the forecast capital expenditure complies with the relevant statutory obligation or technical requirement	Section 3.2.2 Attachment H	
If Rule 79(2)(c)(iv) is relied on to justify new capital expenditure provide in the access arrangement proposal submission:			
(o)	An explanation of the change in demand for existing services necessitating the new capital expenditure, including a measure of the change in demand	Section 3.2.1 Section 6.2.2	
(p)	Reports or other information and documentation that supports how the forecast capital expenditure will meet the increase in demand for existing services	Section 3.2.1 Attachment H Attachment Q	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.3.1.8	**Capital expenditure that is not conforming in the access arrangement period**		
(a)	The amount by asset class for each year of the access arrangement period for forecast non conforming capital expenditure classified into: i. non conforming capital expenditure forecast to be recovered through surcharges ii. non conforming capital expenditure forecast to be added to the speculative capital expenditure account iii. other non conforming capital expenditure	Section 7.2.2.1	
(b)	Details of the forecast speculative capital expenditure account by asset class for the access arrangement period	Section 7.2.2.1	
(c)	If the balance of the speculative capital expenditure account increases at a rate different to the rate of return implicit in a reference tariff (Rule 84(2)), the access arrangement proposal submission a justification for the different rate of return	Section 7.2.2.1	
(d)	The amount of forecast capital contributions by asset class for each year of the access arrangement period	Section 7.2.2.2	
(e)	The amount of capital contributions by asset class for each year of the access arrangement period proposed to be rolled into the capital base under Rule 82(3)	Section 7.2.2.2	
(f)	Where relevant, the extrapolation rates used in deriving forecasts for capital other than conforming capital if different from extrapolation rates provided in 2.3.1.7 (b) of this Notice	Not applicable	
(g)	Details of the mechanism to prevent the service provider from benefiting, through increased revenue, from the capital contributions by a user in the access arrangement period as referred to in Rule 82(3)	Section 6.2.3.1	
2.3.1.9	**Capital redundancy policy in the access arrangement period**		
(a)	An outline of the proposed mechanism to remove redundant assets from the capital base including when the mechanism will take effect and if the mechanism includes a proposal for cost sharing between the service provider and users associated with a decline in demand for pipeline services	Section 7.2.7	AAP 4
(b)	A justification for the mechanism	Section 7.2.7	
(c)	Explain what uncertainty the mechanism may cause and the effect of this uncertainty on the service provider	Section 7.2.7	
If the service provider does not propose to include a mechanism to remove redundant assets:			
(d)	Explain what uncertainty such a mechanism may cause and the effect of this uncertainty on the service provider	Section 7.2.7	
2.3.1.10	**Forecast depreciation in the access arrangement period**		
Refer to 2.3.2 below			

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.3.1.11	**Forecast disposals in the access arrangement period**		
	Amounts by asset class for each year of access arrangement period for forecast disposals	Section 7.2.4	
2.3.1.12	**Rate of inflation and adjustment to the projected capital base in the access arrangement period**		
(a)	The adjustment to the capital base to take account of the effects of inflation over the access arrangement period	Section 7.2.5	
(b)	The rates of inflation used to adjust the capital base over the access arrangement period	Section 8.2 PTRM	
2.3.1.13	**Closing projected capital base in the access arrangement period**		
	The closing balance by asset class for each year of the access arrangement period	PTRM	
2.3.1.14	**Rate of return for the projected capital base**		
(a)	The values of each of the parameters that comprise the weighted average cost of capital (WACC) methodology and capital asset pricing (CAPM) methodology	Section 8.1	
(b)	A justification for the values of each of the parameters used in the WACC derivation	Section 8.1	
(c)	An explanation about how the proposed rate of return complies with Rule 87	Section 8.1	
Method other than weighted average cost of capital and CAPM			
(d)	An outline of the proposed methodology for the rate of return	Not applicable	
(e)	A quantification of the rate of return using this methodology including any justification for the use of parameters in this methodology	Not applicable	
(f)	An explanation about how the proposed rate of return complies with Rule 87	Not applicable	
Rate of return and taxation method			
(g)	Details of the proposed method for dealing with taxation and a demonstration of how the tax allowance is calculated	Section 10.4	
(h)	Where a pre-tax rate of return is proposed provide an explanation of how the proposed tax rate complies with Rule 74(2)(a).	Not applicable	
2.3.2	**Forecast depreciation**		
i.	Amounts for forecast depreciation disaggregated for components by asset class for each year of the access arrangement period. The forecast depreciation should account for and identify depreciation referable to the opening capital base forecast conforming expenditure, other capital expenditure, forecast disposals and other amounts that may be added or deducted to the projected capital based under the Rules	Section 7.2.3 PTRM	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
ii.	Details of the asset lives for each asset	Section 7.2.3 PTRM	
iii.	How the depreciation schedule varies over time in a way that promotes efficient growth in the market for reference services	Section 7.2.3 PTRM	
iv.	How each asset or group of assets is depreciated over the economic life of that group of assets	Section 7.2.3 PTRM	
v.	If applicable, what adjustments have been made to reflect changes in the expected economic life of a particular asset or group of assets	Section 7.2.3	
vi.	How each asset is depreciated only once	Section 7.2.3	
vii.	How the depreciation schedule allows for the service provider's reasonable needs for cash flow to meet financing, non capital and other costs	Section 7.2.3	
viii.	How the depreciation schedules comply with the requirements in Rule 89(2)	Section 7.2.3	
2.3.3	**Estimated cost of corporate income tax**		
(a)	An estimate of the cost of corporate income tax over the access arrangement period	Section 10.4	
(b)	Details of how the estimated cost of corporate tax was calculated	Section 10.4	
2.3.4	**Proposed incentive mechanism in the access arrangement period**		
This section also applies to incentive mechanisms already in place for the earlier access arrangement period that are proposed to continue for the access arrangement period. *For each operating or proposed incentive mechanism:*			
(a)	An outline of the incentive mechanism and its operation in the access arrangement period	Section 10.6.2	
(b)	An explanation of the rationale for any proposed incentive mechanisms including how the incentive mechanism is intended to encourage efficiency of the provision of services and is consistent with the revenue and pricing principles, with reference to those principles	Section 10.6.2	
(c)	Any relevant analyses or reports that support the proposed incentive mechanism	Section 10.6.2	
2.3.5 Operating expenditure			
2.3.5.1	**Operating expenditure in the earlier access arrangement period**		
(a)	Actuals and estimates of operating expenditure by category for each year of the access arrangement period	Section 9.1	
2.3.5.2	**Forecast operating expenditure in the access arrangement period**		
(a)	Operating expenditure forecasts by category for each year of the access arrangement period	Section 9.2.2	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(b)i.	Outline and explain the change in operating expenditure categories between the earlier access arrangement period and the access arrangement period	Section 9.2	
ii.	Describe and explain the nature of material forecast operating expenditure in an operating expenditure category and define the materiality threshold used. This explanation should also outline if there have been changes to the operations of the pipeline from the earlier access arrangement period that have resulted in material changes to operating expenditure category and total operating expenditure in the access arrangement period	Section 9.2	
iii.	An explanation of how the proposed operating expenditure complies with Rule 91, with particular reference to operating expenditure identified in (ii.)	Section 9.2	
iv.	Any assumptions used in deriving the forecast operating expenditure. Note these may include: the unit rates used for key items of expenditure, how these have been developed (including source material) and evidence that they reflect efficient costs; specific rates used to derive or extrapolate expenditure estimates (for example, labour and materials). Where relevant provide: the specific rate used in each year of the access arrangement period; whether the rate is in real or nominal terms; how the derivation or extrapolation has been developed (including source material)	Section 9.2	
2.3.5.3	**Self insurance**		
(a)	The forecast annual insurance premiums over the access arrangement period	Section 9.2.3.5	
(b)	The name and a description of the event	Section 9.2.3.5	
(c)	Whether the event is in relation to a particular asset or class of assets and, if so, identify those assets	Section 9.2.3.5	
(d)	Reasons for self insuring the event. If the event has not previously been self-insured, reasons why it is now being proposed and how the risk of the event was previously accommodated in the access arrangement. If a proposed self-insurance event was previously insured externally, details of existing or previous insurance policies and reasons why external insurance is not relevant in the access arrangement period.	Section 9.2.3.5	
(e)	Details of any quotes obtained from external insurers	Section 9.2.3.5	
(f)	Full details of how the premiums were calculated, including any underlying assumptions used to derive the premiums	Section 9.2.3.5	
(g)	Any expert consultant's report relied on by the service provider in deriving the estimates	Section 9.2.3.5 Attachment C	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(h)	A resolution (including the date of resolution) of the service provider's decision making body to self insure events.	Section 9.2.3.5	
(i)	Details of the administrative arrangements that: i. outline how the self insurance risk is to be reported in the audited special purpose financial statements prepared under section 32 of the ACTEW/AGL Partnership Facilitation Act 2000 ii. outline the procedure for notification and information that will be provided to the AER when the self insurance event occurs	Section 9.2.3.5	
2.3.5.4	**Outsourced expenditure**		
(a)	The name of the external party or parties and contract	Section 3.1.1 Section 9.2.1, Attachment Q	
(b)	Details of how the contract was awarded (for example, by competitive tender)	Section 3.1.1 Section 9.2.1, Attachment Q	
(c)	Details of fees and charges and a description of the goods or services provided	Section 3.1.1 Section 9.2.1, Attachment Q	
(d)	The commencement date and term of the contract	Section 3.1.1 Section 9.2.1, Attachment Q	
(e)	Reasons why the functions were outsourced	Section 3.1.1 Section 9.2.1, Attachment Q	
(f)	Details of the relationships with the party or parties named in (a) including if a party to the contract is an associate of any of the service providers of the pipeline	Section 3.1.1 Section 9.2.1, Attachment Q	
(g)	Define the materiality threshold used	Section 9.2.1, Attachment Q	
(h)	Maintain all contracts identified in the response to 2.3.5.4 in (a) at the service provider's business address identified in the response to 2.1.3 of this Notice.		
2.3.6	**Total revenue**		
	A summary of total revenue for each year of the access arrangement period which includes each of the relevant building block components for the access arrangement period	Chapter 10	
2.4	**Tax asset base**		
(a)	Tax standard life for each asset class as at 1 July 2010	Section 10.4 PTRM	
(b)	Remaining tax life for each asset class as at 1 July 2010	Section 10.4 PTRM	
(c)	Tax asset base or remaining tax asset value for each asset class as at 1 July 2010	Section 10.4 PTRM	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(d)	An estimate of the carry forward tax loss as at 1 July 2010	Section 10.4 PTRM	
2.5 Tariffs			
2.5.1	**Revenue equalisation**		
	Demonstrate that the net present value of the proposed revenue stream is equal to the net revenue stream generated from the building block approach for each reference service.	Section 11.2.3.4	
2.5.2	**Total revenue allocation**		
(a)	Identify and quantify cost pools according to relevant asset classes and operating cost categories for the direct costs of reference services, the direct cost of pipeline services other than reference services, other costs from building block revenue and rebateable services	Section 11.2.2	
(b)	Reconcile total revenue for pipeline services allocated to each reference service and other services	Section 11.2.2	
(c)	An outline of the nature of the allocation keys used to allocate relevant cost pools, explain why these allocation provide the best estimate and provide analysis to support their derivation	Section 11.2.2	
(d)	Supporting information and derivation for any allocation key use to allocate total revenue	Section 11.2.2	
(e)	For rebateable services, a description of the mechanism that the service provider will use to apply an appropriate portion of the revenue generated from the sale of rebateable services to price rebates (or refunds) to users of reference services	Not applicable	
2.5.2.1	**Tariffs – distribution pipelines**		
(a)	Provide a description of each tariff class for each reference service	Section 11.1	
(b)	Explain how tariff classes identified in 2.5.2.1(a) are comprised for each reference service	Section 11.2	
(c)	In explaining the response in 2.5.2.1(b) the service provider needs to provide information about the basis for grouping customers in a tariff class and how this grouping is economically efficient	Section 11.2	
(d)	In explaining the response to 2.5.2.1(b) the service provider needs to provide information about the type of transaction costs it has considered in determining tariff classes, what transaction costs are relevant to the proposed tariff classes and what transaction costs have been avoided. This explanation may include a quantification of the transaction costs that relate to the tariff class and those transaction costs avoided	Section 11.2	
(e)	Define the stand alone cost for each tariff class of each reference service which should outline what costs comprise the stand alone cost of providing each reference service to customers in each tariff class	Section 11.2	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(f)	Define the avoidable cost for each tariff class of each reference service which should outline what costs comprise the avoidable cost of providing each reference service to customers in each tariff class	Section 11.2	
(g)	Demonstrate that expected revenue recovered for each tariff class for each reference service lies on or between stand alone cost and avoidable cost	Section 11.2	
(h)	Define long run marginal cost for each reference service or for each element of the service to which the charging parameter relates, whichever is relevant. The definition of long run marginal cost needs to outline what costs comprise long run marginal cost	Section 11.2	
(i)	Demonstrate how the relevant long run marginal cost has been taken into account in determining a tariff for a tariff class or the charging parameters within a tariff class. This may include a quantification of the long run marginal cost (and its components) that relate to the reference service or element of the reference service to which the charging parameters relate	Section 11.2	
(j)	Explain how the tariff or charging parameters that comprise a tariff have been determined with regard to relevant transactions costs. In doing so, the service provider needs to provide information about the type of transaction costs associated with the tariff or charging parameters of the tariff. This explanation may include a quantification of the transaction costs that relate to the tariff class and those transaction costs avoided	Section 11.2	
(k)	Explain how the tariff or charging parameters that comprise a tariff have been determined with regard to how customers may respond to price signals. This explanation should include analysis (preferable quantified) about customers' responsiveness to price signals relevant to the tariff or charging parameters.	Section 11.2	
(l)	Provide any relevant analyses or reports that support the answers for charging parameters	Section 11.2	
In circumstances where expected revenue across all tariff classes for a reference service is lower than total revenue allocated to that reference service			
(m)	Quantify the difference in revenue by reference to the expected revenue for each reference service and total revenue allocated to each reference service	Section 11.2.3.4	
(n)	Demonstrate how the shortfall for each reference service is allocated across each tariff class and where relevant across each charging parameter in a tariff class for that reference service and how this was done with minimum distortion to efficient patterns of consumption	Section 11.2.3.4	
2.5.3	**Prudent discounts**		
(a)	Provide full details and justification of all prudent discounts.	Not applicable	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(b)	Demonstrate that a discount is necessary to respond to competition or maintain efficient use of the pipeline.	Not applicable	
(c)	Demonstrate (by quantifying the effect) that without the discount, reference tariffs would be higher than what they would be with the discount	Not applicable	
2.5.4 Reference tariff variations			
2.5.4.1	**Tariff variation mechanism**		
(a)	Outline the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism.	Section 11.3.1	Part 6
(b)	Justify the reference tariff variation mechanism and address the factors contained in Rule 97(3) Note: In doing so the service provider needs to establish a materiality level for events that will be passed-through for the AER to have regard to the possible effects of the reference tariff variation mechanism on the administrative costs of the AER, the service provider and users or potential users.	Section 11.3.1	Part 6
(c)	Outline how the reference tariff mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)) Note: In order to address the requirements in Rule 97(4) the service provider will need to outline the administrative arrangements for periodic reviews of tariffs including timing of notifications to the AER.	Section 11.3.1	Part 6
2.5.4.2	**Cost pass through mechanism**		
(a)	Clearly define and describe each cost pass through event	Section 11.3.2	Part 6
(b)	Justify cost pass through mechanism and address the factors contained in Rule 97(3) Note: In doing so the service provider needs to establish a threshold level of costs to be passed-through which considers the administrative costs of the AER, the service provider and users or potential users (Rule 97(3)(b)).	Section 11.3.2	
(c)	Explain how each cost pass through event is relevant to a building block component in Rule 76 and is either foreseen or unforeseen and the costs of the event are uncontrollable and therefore cannot be included in forecasts for total revenue	Section 11.3.2	
(d)	Explain how the cost pass through mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)) Note: In order to address the requirements in Rule 97(4) and Rule 97(3) the service provider will need to outline the administrative arrangements for cost-pass through events and their relationship to other periodic reviews for other tariff variation mechanisms (especially timing of notifications to the AER).	Section 11.3.2	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
2.6 Other information to be made available on request or provided			
2.6.1 Other information to be provided			
2.6.1.1	**Models and user manuals**		
	All financial models including, but not limited to, tariff, revenue, cost allocation and demand forecasts, along with user manuals that underlie and support the access arrangement proposal and access arrangement information. The models provided should not include information that is hard-coded unless it is referenced to source documentation or information. Wherever possible information contained in models that is based on derived data or inputs should be linked to that derived data or inputs.	Attachments	
2.6.1.2	**Consultants' reports**		
(a)	Copies of consultants' or external expert reports relied on to support or justify components of the access arrangement proposal and the access arrangement information	Attachments	
(b)	Terms of reference for each consultancy identified in (a)	Within consultants report where applicable	
2.6.2	**Index of information**		
	An index of information outlining where the information to be provided in Attachment 2 is contained in the access arrangement proposal submission. It should do this with reference to the number attached to information request in Attachment 2	Attachment B	
2.6.3	**Information to be maintained at service providers premises**		
(a)	Except in cases where it would be impractical, the information should be kept in an electronic format	Not applicable to AAI document	
(b)	The service provider in 2.1.1 of this Notice must maintain at its business address the following information and documentation that is relied on in the access arrangement proposal submission. This needs to be made available for inspection or in a form that can be provided to the AER on request i. Procurement and contracting out policies ii. Associate contracts iii. Consultants reports, other than those specifically requested to be provided to the AER in this Notice iv. Data, models, internal policies and any other supporting information and documentation, other than those specifically requested to be provided to the AER in this Notice	Not applicable to AAI document	

RIN reference		Access arrangement information reference	Access arrangement proposal reference
(c)	The service provider in 2.1.1 of this Notice must maintain at its business address the assets register per clause 4.16 in the Access Arrangement for ActewAGL Gas Distribution System in ACT and Greater Queanbeyan dated November 2004	Not applicable to AAI document	
(d)	The service provider in 2.1.1 of this Notice must maintain at its business address the database for capital contributions per clause 4.17 in the Access Arrangement for ActewAGL Gas Distribution System in ACT and Greater Queanbeyan dated November 2004	Not applicable to AAI document	

C Marsh Pty Ltd: Self Insurance risk quantification report

Confidential attachment provided as a separate document.

D Information of self insured events

Confidential attachment provided as a separate document.

E Jemena Asset Management: Benchmarking comparison study

Attachment provided as a separate document.

F ActewAGL Distribution performance benchmarking study

Confidential attachment provided as a separate document.

G NIEIR Natural gas projections for ActewAGL Distribution

Attachment provided as a separate document.

H Engineering assessments and HFL pre-feasibility and feasibility documentation

Confidential attachments provided as a separate documents.

I Parsons Brinckerhoff: Assessment of unit rates used in proposed expenditure program

Confidential attachment provided as a separate document.

J Competition Economists Group (CEG): Report on escalators

Attachment provided as a separate document.

K Unit Rates applied to market expansion capital expenditure

Confidential attachment provided as a separate document.

L WACC information

Confidential attachments provided as a separate documents.

M Competition Economists Group: Dividend Growth Model and Equity Beta

Confidential attachment provided as a separate document.

N Step changes

Confidential attachment provided as a separate document.

O Unaccounted for Gas benchmarks

O.1 Australian jurisdictions: Victoria

The Essential Services Commission (ESC) of Victoria sets UAG benchmarks for two different types of customers - Class A (customers using > 250TJ) and Class B (customers using < 250 TJ). This approach is different from that employed by NSW, Queensland and South Australia where a single UAG benchmark is applied to the network. During the Gas Access Arrangement Review for 2008 – 2012, some Victorian distributors recommended that the double-benchmark system be replaced by a single UAG benchmark.[161] The ESC acknowledged that a single UAG benchmark was appropriate in principle given that Class A and Class B injections were not measured separately, but it also said that Class A customers were served by high pressure mains that had very low rates of leakage. On this basis, the ESC upheld the existing UAG benchmarking system and proposed the UAG targets for the 2008-2012 Access Arrangement period shown in Table O.1.[162]

Table O.1 ESC UAG targets for the 2008-2012 Access Arrangement period

	Class B benchmarks					Class A benchmarks
	2008	2009	2010	2011	2012	2008-2012
Envestra (Victoria)	2.8	2.8	2.7	2.7	2.6	0.3
Envestra (Albury)	3.0	3.0	3.0	3.0	3.0	0.1
Multinet	3.2	3.2	3.2	3.1	3.1	0.3
SP AusNet	5.1	5.1	5.0	5.0	4.9	0.3

Note: UAG benchmarks are expressed as percentage of total injections.

Given the ESC's approach to benchmarking and the limited data available from public sources, it is impossible to infer a single UAG allowance applicable for each network. What can be said is that the total UAG benchmark would be a volume-weighted average of Class A and Class B UAG benchmarks. Given that there are no customers in the ACT with consumption greater than 250TJ, one could use Class B benchmarks for comparison. However, such a comparison would be biased towards higher values of UAG and should therefore be used with caution. Despite the bias, it is possible to glean that the level of UAG in the ACT is broadly in line with the Victorian experience.

The ESC also established a separate UAG benchmark for non-PTS (non-Principal Transmission System) networks of 2.0 per cent. This benchmark is relevant for ActewAGL in that the non-PTS networks are newer networks with little or no cast iron mains which are significantly more prone to leakage. Generally these networks have similar characteristics as the ACT Queanbeyan network with a large proportion of small tariff end users and only a small proportion of large contract customers

[161] This change was proposed by SPAusNet and supported in principle by Origin Energy and AGL. See *Gas Access Arrangement Review 2008-2010*, Draft Decision, 28 August 2007, p.147.
[162] Essential Services Commission of Victoria, Gas Access Arrangement Review 2008-2012, Final Decision, 7 March 2008, p.16.

O.2 Australian jurisdictions: Queensland

The Queensland gas distribution networks, Allgas and Envestra, tend to have materially higher levels of UAG than other networks in Australia. In 2001, the Queensland Competition Authority (QCA) considered the level of UAG on other distribution networks and established a benchmark UAG rate of 3 per cent of total gas throughput for Allgas and 4.8 per cent for Envestra.

Allgas has since stated that its level of UAG fell from 4.7 per cent in 2001-02 to 3.3 per cent in 2004-05. It also forecast further reductions in UAG in the future.[163] Envestra said that its UAG level rose from 4.8 per cent in 2001-02 to 5.8 per cent in 2004-05. However, it forecast reductions in UAG in future years.[164]

Queensland's UAG benchmarks are not surprising given a large proportion of cast iron mains in the Allgas and Envestra systems. Such mains are characterised by higher gas leakage, which is being gradually rectified in the process of replacement of older cast iron mains with newer plastic mains. As was mentioned above, there are no cast iron mains in the ActewAGL Distribution network.

O.3 Australian jurisdictions: New South Wales

For Jemena Gas Network (JGN), IPART set a UAG benchmark of 2.2 per cent of gas receipts for 2005/06 and 2.1 per cent of gas receipts for 2006/07 to 2009/10.[165] In its proposed revision to AGL Gas Network's (AGLGN) Access Arrangement, AGLGN forecast that UAG would remain at 2.2 per cent of total gas deliveries, the level experienced in 2003.[166] Therefore, even though in the proposed revision AGLGN did not provide a detailed time series of actual UAG data, it is reasonable to infer that the level of UAG in 2003-2004 was in a range around 2.2 per cent.

O.4 Australian jurisdictions: Western Australia

For the first Access Arrangement period, Jan 2000 – Dec 2004, the Regulator for the South-West and Mid-West Gas Distribution Systems approved a decline in UAG as a proportion of total delivered gas from 2.7 per cent to 2.5 per cent. For the second period, Alinta Gas Networks projected the proportion of UAG for 2005 to be 2.7 per cent and 2.8 per cent for each of the remaining years, 2006-2009.

The Economic Regulation Authority was not satisfied with Alinta's forecast and decided that 2.5 per cent of gas received would be the best estimate of annual UAG for the second regulatory period.[167]

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[163] Queensland Competition Authority, Revised Access Arrangement for Gas Distribution Networks: Allgas Energy, Final Decision, May 2006, p.87.
[164] Queensland Competition Authority, Revised Access Arrangement for Gas Distribution Networks: Envestra, Final Decision, May 2006, p.127.
[165] Jemena Access Arrangement for NSW Gas Networks, 7 March 2007.
[166] Revisions to AGLGN's Access Arrangement and Access Arrangement Information, December 2004, p.37
[167] Economic Regulation Authority, Final Decision on the Proposed Revisions to the Access Arrangement for the South-West and Mid-West Gas Distribution Systems, 12 July 2005, p.79.

O.5 Overseas jurisdictions: New Zealand, the UK, and the USA

In a study prepared by Maunsell AECOM for the New Zealand Gas Industry Company, the long-term UAG was estimated to be 2.45 per cent in 2006. Maunsell also specified that before industry deregulation in the early to mid-1990s, total UAG for the New Zealand distribution networks was in the order of 2 per cent.[168] All-in-all, Maunsell came to a conclusion that a national benchmark of ±2 per cent was achievable for New Zealand and encouraged the Gas Industry Company to work towards this goal.[169]

In the Gas Distribution Price Control Review Final Proposals[170], Ofgem, the British regulator, defines gas shrinkage as gas lost from the network through leakage, theft and own use gas. While theft represents a relatively small proportion of the total shrinkage, leakage appears to be an issue for the UK gas networks. The level of shrinkage approved for the first six months of the new control period beginning 1 April 2008 was between 0.46 per cent for the Scotland network and 0.89 per cent for the South West.

The UK shrinkage factors appear to be relatively low compared to the levels of UAG estimated for Australia and New Zealand. From the definition of shrinkage, it appears plausible that gas measurement uncertainty was not considered. Further investigation showed that metering error was in fact included in Ofgem's definition of shrinkage, but that it was estimated to be very small. Ofgem views metering error as stemming from two sources: inaccurate measurement of gas offtake from customers' premises and the differences in the calorific value of gas at different points on the network.

Earlier in this report, ActewAGL pointed out that gas measurement uncertainty can also be attributed to meter ageing and degradation, billing cycle issues and the inherent uncertainties surrounding meter readings. The impact of these factors may range up to 1-1.5 per cent. This view is confirmed by the Maunsell AECOM study that indicates "the billing error including metering and data processing as distinct from shrinkage (which represents physical losses) would be in the order of 1 to 1.5 per cent."[171] Combined with the shrinkage factors from the UK, this could lead to a UAG estimate of roughly 1.5 per cent to 2.4 per cent.

The United States natural gas pipeline operators provide the Federal Regulatory Energy Commission with gas consumption data, including UAG. However, this information has proven difficult to locate in the public domain. Research showed that according to one of the sources, distribution system UAG in the USA in 2002 was 1.5 per cent and the appropriate range for UAG was between 0.88 per cent and 2 per cent.[172] Another source pointed out that the US gas distribution industry standard for UAG was 2 per cent.[173] However, some distribution businesses have had UAG figures in excess of 2 per cent

[168] Op. cit., Maunsell/ AECOM, p.13
[169] Op. cit., Maunsell/ AECOM, p.19
[170] Ofgem, Gas Distribution Price Control Review, Final Proposals, 3 December 2007, p.86-87
[171] Op. cit., Maunsell/ AECOM, p.13
[172] Alberta Energy and Utilities Board, *ATCO Pipelines North Unaccounted-for-Gas Allocation Methodology*, Table 2: Table 1.3 (Updated) Transmission and Distribution UFG – United States
[173] *Administrative Law Judge Recommends PUC Approval of Settlement Agreement Reached in PG Energy Rate Case*, PR Newswire, http://www.prnewswire.com/news/index_mail.shtml?ACCT=104&STORY=/www/story/10-05-1998/0000764781&EDATE=, accessed 17 March 2009.

approved by local Public Utilities Commissions. These estimates are consistent with the level of UAG experienced in the ACT.

P ActewAGL Distribution gas network associate contracts

P.1 Approved associate contracts

Table P.1 Details of approved associate contracts

Name of contract	Parties to contract	Nature of goods and services provided or obtained	Relationship to each service provider
Gas Transport Services Agreement for large customers	ACTEW Distribution Ltd and Jemena Networks (ACT) Pty Ltd trading as ActewAGL Distribution and ACTEW Retail Ltd and AGL ACT Retail Investments Pty Ltd trading as ActewAGL Retail	ActewAGL Distribution is required to provide certain services to gas suppliers in the ACT, Queanbeyan and Palerang under its access arrangement. ActewAGL Distribution provides ActewAGL Retail with (a) non-tariff services; and (b) meter data services while they remain non-contestable services. The agreement covers all customers on ActewAGL Retail's non-tariff list and provides a procedure for updating that list as customers are transferred to and from ActewAGL Retail.	The parties to the contract are associates in that a single partner to each (ACTEW Distribution Ltd and ACTEW Retail Ltd) has a common parent, ACTEW Corporation Ltd.
Gas Transport Services Agreement for large customers	ACTEW Distribution Ltd and Jemena Networks (ACT) Pty Ltd trading as ActewAGL Distribution and ACTEW Retail Ltd and AGL ACT Retail Investments Pty Ltd trading as ActewAGL Retail	ActewAGL Distribution is required to provide certain services to gas suppliers in the ACT, Queanbeyan and Palerang under its access arrangement. ActewAGL Distribution provides ActewAGL Retail with (a) tariff services; and (b) meter data services while they remain non-contestable services. The agreement covers all customers on ActewAGL Retail's tariff list and provides a procedure for updating that list as customers are transferred to and from ActewAGL Retail. All customers on ActewAGL Retail's tariff list are non-franchise customers pursuant to an ACT Government declaration under subsection 18(4) of the Utilities Act 2000 in April 2001 (DI2001-94, Utilities (Non-Franchise Natural Gas Customers) Declaration 2001).	The parties to the contract are associates in that a single partner to each (ACTEW Distribution Ltd and ACTEW Retail Ltd) has a common parent, ACTEW Corporation Ltd.

Q Policies strategies and plans

Q.1 Asset Management Plan

Q.2 Service Plan

Q.3 ActewAGL Capitalisation policy

Q.4 Request Utility for Gas Supply (RUGS) process

Q.5 Corporate cost allocation methodology

Confidential attachments provided as a separate documents.

R Models

R.1 Roll forward model (RFM)

R.2 Post tax revenue model (PTRM)

R.3 Tax roll forward model

R.4 Final gas networks access arrangement 2005/10 model

R.5 Revenue allocation model

R.6 Equity raising costs model

R.7 Allocation of revenue to tariff and contract

Confidential attachments provided as a separate documents.

S ActewAGL outsourced expenditure

S.1 Summary of outsourced expenditure

S.2 Distribution Asset Management Services (DAMS) Agreement

S.3 Ecowise Environmental GIS contract

S.4 Field Force meter reading contract

Confidential attachments provided as a separate documents.

T Competition Economists Group: Estimating the cost of 10-year BBB+ debt

Attachment provided as a separate document.

U Statutory Declaration