Access Arrangement Information

for Envestra's
Victorian Distribution System

2 April 2002

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DISCLAIMER

This document has been prepared solely for the purpose of compliance with the *Gas Pipelines Access (Victoria) Act 1998* and the *National Third Party Access Code for Natural Gas Pipeline Systems (Access Code).*

It is designed solely to enable Users and Prospective Users to understand the derivation of elements in the accompanying Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Access Code.

This document is not intended for any other purpose and should not be relied upon as the basis for any decision to transport or retail gas through the Distribution System or to buy or sell, or otherwise deal in, Envestra's securities or for any other purpose.

1. INTRODUCTION

1.1. Purpose of this Document

This document is the Access Arrangement Information in relation to the Access Arrangement for the Envestra Limited (‘Envestra’) Victorian Distribution System (‘the Distribution System’) and is submitted by Envestra (ABN 19 078 551 685) to the Essential Services Commission (‘the Regulator’) in accordance with section 2 of the Access Code.

The purpose of this document is to set out such information as is necessary to enable Users and Prospective Users to understand the derivation of the elements of the Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Access Code.

1.2. Background

Envestra commenced operations on 1 July 1997. It is the beneficial owner of the Distribution System and other natural gas distribution infrastructure assets in South Australia, Queensland, New South Wales and the Northern Territory. Envestra is also the owner of the Riverland and Mildura natural gas transmission pipelines in South Australia and Victoria, and the Palm Valley to Alice Springs transmission pipeline in the Northern Territory.

On 17 December 1998, the Office of the Regulator-General (now the Essential Services Commission) approved an Access Arrangement for the Stratus Networks Pty Ltd distribution system. The Distribution Licence was transferred from Stratus Networks to Vic Gas Distribution Pty Ltd on 30 March 1999. Clause 1.1 of the Access Arrangement describes the relationship between Envestra Limited and Vic Gas Distribution Pty Ltd.

1.3. The Distribution System

The Distribution System serves the northern, outer eastern and southern areas of Melbourne, Mornington Peninsula and rural communities in northern and north-eastern Victoria. The Distribution System is divided into three Zones – North, Central and Murray Valley. Maps outlining the areas covered by the Distribution System have been lodged with the Regulator and are available from Envestra’s website “www.envestra.com.au”. Statistics relating to the Distribution System are included in sections 21 and 22 of this Access Arrangement Information.

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1.4. Interpretation

Terms used in this Access Arrangement Information have the same meaning as they have in the Access Arrangement (see clause 2 of the Access Arrangement).

References to years are calendar years, unless indicated otherwise. Monetary values shown in tables are in nominal dollars unless indicated otherwise.

1.5. Contact Details

The contact person for further details in relation to this Access Arrangement Information and the Access Arrangement to which it relates is:

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2. CONTENTS OF THE ACCESS ARRANGEMENT

2.1. Access Code Requirements

Section 2.5 of the Access Code states that the Access Arrangement may include any relevant matter, but must include at least the elements described in sections 3.1 to 3.20 of the Access Code. Sections 3.1 to 3.20 of the Access Code require the Access Arrangement to include the following elements:

- a Services Policy (sections 3.1 and 3.2 of the Access Code);
- a Reference Tariff for at least one Service that is likely to be sought by a significant part of the market (a Reference Service) and for each other Service that is likely to be sought by a significant part of the market and for which the Regulator considers a Reference Tariff should be included (sections 3.3 and 3.4);
- a Reference Tariff Policy which describes the principles to be used to determine Reference Tariffs (section 3.5);
- the terms and conditions on which the Service Provider will supply each Reference Service (section 3.6);
- a Capacity Management Policy – a statement of whether the Pipeline is a Contract Carriage Pipeline or a Market Carriage Pipeline (sections 3.7 and 3.8);
- a Trading Policy in respect of Contract Carriage Pipelines, which describes the rights of a User to trade its right to a Service to another person (sections 3.9 to 3.11);
- a Queuing Policy – a policy for determining the priority a Prospective User has to obtain access to Spare Capacity and Developable Capacity (sections 3.12 to 3.15);
- an Extensions/Expansions Policy – a policy which sets out, among other things, whether any extension or expansion will be treated as part of the Covered Pipeline under the Access Code and how the extension or expansion will affect Reference Tariffs (section 3.16); and
- a Revisions Submission Date and a Revisions Commencement Date (sections 3.17 to 3.20). These are the dates by which the Service Provider must submit revisions to the Access Arrangement and upon which these revisions are intended to take effect.

Sections 2.2 and 2.6 of the Access Code require that Access Arrangement Information must be submitted with an Access Arrangement and must contain such information as, in the opinion of the Regulator, would enable Users and Prospective Users to:

- understand the derivation of the elements in the Access Arrangement; and

- form an opinion as to the compliance of the Access Arrangement with the provisions of the Access Code.

Section 2.8 of the Access Code requires that information included in the Access Arrangement Information may be categorised or aggregated to the extent necessary to ensure the disclosure of the information is, in the opinion of the Regulator, not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User.

2.2. Compliance

The Access Arrangement includes each of the elements that are required to be included. This document addresses the compliance of each element of the Access Arrangement with the requirements of the Access Code. In accordance with the Access Code this information has been categorised and/or aggregated where necessary to prevent undue harm to the legitimate business interests of Users, Prospective Users and Envestra.

3. OUTCOME OF FIRST ACCESS ARRANGEMENT PERIOD

3.1. Introduction

The Access Arrangement approved by the Regulator in December 1998 set out the tariffs, policies and terms and conditions to apply to third party access to the Distribution System for the period 1999 to 2002. The Final Decision determined the target revenue to be recovered in the First Access Arrangement Period. This target revenue (adjusted for inflation) is as follows:

$m	1999	2000	2001	2002
Non-Capital Costs	31.4	32.0	33.3	34.8
Depreciation	19.9	21.7	23.7	25.8
Return on Assets	49.7	52.5	56.8	62.0
Target Revenue	**101.0**	**106.2**	**113.8**	**122.6**

Table 1 Target revenue approved by the Regulator 1999-2002 ($m)

3.2. Target Versus Actual Revenue

Revenue received by Envestra over the three year period 1999 to 2001 is set out in the following table:

$m	1999	2000	2001
Actual Revenue	97.4	102.4	107.6
Variance from target revenue	(3.6)	(3.8)	(6.2)

Table 2 Actual revenue 1999-2001($m)

Table 2 demonstrates that Envestra has been unable to recover the target revenue approved by the Regulator in the 1998 Final Decision. Over the three-year period 1999 to 2001, revenue received by Envestra was $13.6 million less than the target revenue.

A major cause of the reduced revenue was overly optimistic forecasts of gas demand imposed by the Regulator on Envestra in the Final Decision. Over the period 1999 to 2001, Tariff V gas load was 2.2 PJ below the Regulator's forecast. This is illustrated in the following table:

Tariff V Gas Load (PJ)	1999	2000	2001
Forecast	28.2	29.1	30.1
Actual	27.2	29.1	28.9
Variance from forecast	(1.0)	(0.0)	(1.2)

Table 3 Actual and Forecast Tariff V Gas Load

Over the same period, Tariff D gas load was about 20% less than forecast.

A further factor contributing to the reduced loads was warmer than average weather over the period 1999 to 2001. The warmer weather appears to be due to both year to year variations as well as an underlying long-term decline in 'Effective Degree Days', reducing the demand for gas. There is also evidence to suggest that domestic consumers are purchasing fewer gas appliances than they did previously and that improvements in house design, eg thermal efficiency and insulation have contributed to a decline in gas consumption. In addition new connections failed to reach forecasts, despite an exceptionally buoyant housing market.

Finally, the price control formulae applying to Envestra over this period have prevented the business from increasing tariffs to the level required to recover the target revenue.

In addition to reduced revenue, Envestra also experienced cost pressures. During the First Access Arrangement period, Envestra was unable to contain Non-Capital Costs within the levels prescribed by the Regulator. Over the period 1999 to 2001, Non-Capital Costs exceeded regulatory forecasts by up to 15%, as shown in the following table.

Non-Capital Costs ($ m)	1999	2000	2001
Forecast	31.4	32.0	33.3
Actual	35.8	36.8	37.8
Variance from forecast	4.4	4.8	4.5
% Difference	14.0	15.0	13.5

Table 4 Non-Capital Costs 1999-2001

This occurred in spite of the cost improvement initiatives implemented by Envestra following its purchase of the business in March 1999.

The Regulator noted in the 1998 Final Decision that the absence of a history for the distribution businesses precluded the utilisation of a rigorous methodology for forecasting Non-Capital Costs. In addition, benchmarking work undertaken by Ewbank Preece for the Regulator suggested that the budgeted Non-Capital Costs were towards the lower end of the feasible range[1]. It is now clear that the original regulatory benchmarks for Non-Capital Cost forecasts were too low. Non-Capital Costs need to increase in the Second Access Arrangement Period.

These cost pressures were exacerbated by adverse regulatory decisions (see Attachment C) including:

- A 260% increase in licence fees backdated to 1 July 2001; and
- Inadequate tariff increases to maintain Envestra in an economically neutral position following the introduction of the GST.

In contrast to Non-Capital Costs, Envestra was able to contain New Facilities Investment within the level approved by the Regulator, as shown in the following table.

New Facilities Investment ($m)	1999	2000	2001
Forecast	31.9	29.0	27.9
Actual	27.5	24.9	26.3
Variance from forecast	(4.4)	(4.1)	(1.6)
% Difference	-13.8	-14.1	-5.7

Table 5 New Facilities Investment 1999-2001

A major factor contributing to low New Facilities Investment relative to forecast was a reduced number of connections of Tariff V consumers. This occurred despite excellent economic conditions and an unprecedented housing boom assisted by the Federal Government's new home buyers incentives. Envestra's inability to meet connection forecasts as determined in the Final Decision supports the conclusion drawn earlier that the demand forecasts set by the Regulator in 1998 were too optimistic.

Tariff V Connections	1999	2000	2001
Forecast	417,500	430,600	443,600
Actual	411,387	422,728	431,821
Variance from forecast	(6,113)	(7,872)	(11,779)

Table 6 Actual and Forecast Tariff V Connections 1999-2001

3.3. Service Levels

Despite lower revenue, Envestra maintained a high quality distribution service. Statistics describing various dimensions of service quality are provided to the Regulator on a quarterly basis. Each year the Regulator releases a report comparing

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[1] ORG Final Decision, p 69

the performance of distribution businesses operating in Victoria. This section draws upon the results provided in these reports.

As stated in reports published by the Regulator, in both 1999 and 2000 the number of gas outages were less than the targets prescribed by the Regulator for Envestra (see Table 7). While the number of gas outages increased from 1999 to 2000, this was due to damage to Envestra's infrastructure caused by third parties[2]. Notwithstanding this, the duration of lost supply per consumer was less than 60 seconds per annum demonstrating that Envestra's distribution system is very reliable.

Gas Outages	**Target**	**Actual**	
		1999	**2000**
Greater than 5 customers	25	7	24
Greater than 100 customers	2	1	2
Greater than 1000 customers	1	0	0

Table 7 Gas outages 1999-2000

The number of gas leaks has been well below targets set by the Regulator demonstrating that Envestra's Distribution System is well maintained and technically efficient. Moreover the number of publicly reported leaks per 1000 customers has remained relatively constant from 1999 to 2000.

	Target	**Actual**	
		1999	**2000**
Gas Leaks/1000 Customers	25	18.5	18.4

Table 8 Publicly Reported Gas leaks 1999-2000

Envestra has maintained high customer service, exceeding targets set by the Regulator in relation to "response times to customer calls":

[2] ORG Gas Industry Comparative Report 1999 and 2000

Customer Call Response Target	Result	
	1999	**2000**
Metropolitan: business hours - 95% within 60 minutes	99.9	96.1
Metropolitan: after hours - 90% within 60 minutes	99.9	97.1
Country: all hours – 90% within 60 minutes	99.9	93.9

Table 9 Response to customer calls

3.4. Concluding Comments

Envestra has provided a high quality gas distribution service over the last Access Arrangement Period. However, due to unrealistic forecasts and assumptions imposed on Envestra by the Regulator in the 1998 Final Decision compounded by seasonal factors, Envestra has been unable to recover the target revenue or meet Non-Capital Cost targets prescribed by the Regulator.

Realistic forecasts are incorporated in this revised Access Arrangement which increase Envestra's target revenue over the period 2003-2007 to an appropriate level. The basis for the forecasts are detailed in this Access Arrangement Information.

4. SERVICES POLICY

4.1. Access Code Requirements

Section 3.1 of the Access Code states that an Access Arrangement for a Covered Pipeline must include a policy on the Service or Services to be offered. The Access Code refers to this policy as a Services Policy.

Section 3.2 of the Access Code states that the Services Policy must comply with certain principles. These principles are as follows:

- the Access Arrangement must include a description of one or more Services that the Service Provider will make available to Users or Prospective Users, including:
  - one or more Services that are likely to be sought by a significant part of the market; and
  - any Service or Services which in the Regulator's opinion should be included in the Services Policy (section 3.2(a) of the Access Code);
- to the extent practicable and reasonable, a User or Prospective User must be able to obtain a Service which includes only those elements that the User or Prospective User wishes to be included in the Service (section 3.2(b) of the Access Code); and
- to the extent practicable and reasonable, a Service Provider must provide a separate Tariff for an element of a Service if this is requested by a User or Prospective User (section 3.2(c) of the Access Code).

4.2. Compliance

4.2.1 Haulage Reference Services

Section 5 of the Access Arrangement sets out the Services Policy for the Distribution System. It includes a description of the Services available to Users and Prospective Users.

Envestra is proposing to provide two Haulage Reference Services:

- Tariff D Haulage Reference Service – this service provides for the haulage of Gas to Customers with an annual consumption that exceeds 10TJ in the preceding 12 month period or exceeds 10GJ in any hour in the preceding 12 month period; and
- Tariff V Haulage Reference Service – this service applies to all other Customers.

Both services include:

- allowing the injection of Gas at a Transfer Point;
- haulage of Gas from a Transfer Point to a DSP; and
- allowing the withdrawal of Gas at a DSP.

Envestra believes that the proposed Haulage Reference Services are the haulage Services that are likely to be sought by a significant part of the market during the Second Access Arrangement Period. These Services are essentially identical to those currently being provided to Users, and Users have not indicated a demand for other haulage Services. Envestra is unaware of any changes in circumstances or future developments that are likely to materially affect this situation during the Second Access Arrangement Period.

As for the First Access Arrangement Period, the Haulage Reference Services do not include or provide for meter reading and the provision of associated data. However, it is recognised that once the responsibility for this function is transferred to network owners, this service will be incorporated into the Haulage Reference Service. Envestra will review this at the next review of the Access Arrangement.

4.2.2 Ancillary Reference Services

In addition to the Haulage Reference Services, Envestra recognises that additional services may be requested by a significant part of the market. There are a number of discrete services which a User may request at some point in time. However, some of these services, e.g. disconnection in the street (at the junction of the gas main and gas service) and disconnection for illegal use, are not frequently requested[3] and therefore do not qualify as Reference Services.

Envestra has identified a need for three Ancillary Reference Services which will apply for Residential Customers:

- Meter and Gas Installation Test – this service is provided upon request where there is an element of doubt that the meter is reading correctly. This service is currently undertaken approximately 200 times per year, and is known in the industry as a "high bill investigation". It usually involves the installation of a 'check meter' in series with the Customer's meter for a period of time, as well as testing of the Customer's Gas Installation for soundness. (Unusually high consumption may be due to a gas leak or change usage pattern rather than an inaccurate meter).

- Disconnection Service and Reconnection Service – these services are required by Retailers as part of their debt management process. Disconnection involves taking whatever action is necessary at the location of the Meter Installation to prevent the flow of Gas. This includes one or more of the following:
  - turning off the service valve at the Meter Installation, with or without a locking device;
  - inserting a wad in pipework downstream of the isolation valve;
  - removal of the Meter.

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[3] Envestra only receives one or two requests for these services per year.

The Reconnection service involves reversing the actions taken to perform a Disconnection plus actions necessary to restore Supply safely to the Customer. This involves purging of the Gas Installation and relighting appliances where applicable. The additional work required in the Reconnection is reflected in the higher charge for this service.

The following table presents the forecast number of requests for Ancillary Reference Services over the Second Access Arrangement Period, and reflects the current (and stable) demand, i.e. the forecast assumes no change in the current demand for these services.

Forecast Demand for Ancillary Reference Services	2003	2004	2005	2006	2007
Meter and Gas Installation Test	200	200	200	200	200
Disconnection	400	400	400	400	400
Reconnection	7,500	7,500	7,500	7,500	7,500

Table 10 Forecast Quantity of Ancillary Reference Services

The forecast Reconnections are higher than Disconnections as Retailers frequently perform their own Disconnections.

With the onset of full retail contestability, additional services will be required. No costs or revenue associated with such services have been included in the Access Arrangement. Cost recovery for those services identified as necessary for full retail contestability will be via an Order in Council under section 68 of the Gas Industry Act 2001. The Regulator has an obligation to separately approve the level of cost recovery for those services, which will include scheduled meter readings and special meter readings.

4.2.3 Negotiated Services

Users may require services that are different from the Reference Services and Envestra will negotiate such services on a case by case basis.

The price of Reference Services takes into account the corresponding service levels and business risks associated with providing the services in accordance with the standard terms and conditions. Users are able to negotiate different service levels or different terms and conditions, and the delivery of such a service will be priced accordingly (as a Negotiated Service).

Where a User or Prospective User cannot agree a price with Envestra for a Negotiated Service, the User can file an access dispute with the Regulator in accordance with section 6 of the Access Code.

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4.2.4 Service Standards and Quality

In addition to the terms and conditions applicable to the provision of a Service (Part C of the Access Arrangement), Envestra will provide Services in accordance with certain minimum service standards and quality levels.

Envestra already supplies the Regulator with certain reliability indicators, and the Regulator has indicated that it proposes improvements to the collection and reporting of reliability performance over the coming regulatory period. The Regulator has also suggested consideration will be given in future regulatory resets whether a more or less rigorous set of reliability performance targets should be introduced. However, at this point in time there is insufficient evidence to warrant the cost of introduction of more onerous reporting systems, and it should be noted that Envestra has not incorporated any costs in its Reference Tariffs for the delivery of service quality higher than what currently exists.

Should Envestra be required, for example through licence requirements or other Regulatory Instruments (such as the Distribution System Code), to implement systems to collect and monitor information for a more rigorous set of reliability indicators or to provide a higher level of service, Envestra will require pass-through of such costs in accordance with section 5.2 of the Access Arrangement. The Regulator has foreshadowed a review of the key performance indicators for gas distributors with a view to assessing the appropriateness of the types of indicators and the target levels[5].

Similarly, at this point in time there is insufficient evidence to warrant the cost of introduction of guaranteed service levels (GSLs), and it should be noted that Envestra has not incorporated any costs in its Reference Tariffs in relation to GSLs, i.e. the cost of implementing systems to collect the necessary information, make payments related to GSLs, and the direct cost of those payments. Should Envestra be required to implement such systems, Envestra will require pass-through of the costs in accordance with section 5.2 of the Access Arrangement.

[5] P 25, ORG Further Guidance to gas distributors, Dec 2001

5. TOTAL REVENUE FORMULA

5.1. Access Code Requirements

Section 8.4 of the Access Code provides that the Total Revenue can be calculated according to one of three approaches:

- a Cost of Service approach whereby Total Revenue is equal to the sum of
  - a Rate of Return on the value of the Capital Base; plus
  - depreciation of the Capital Base; plus
  - the operating, maintenance and other Non-Capital Costs incurred in providing all Services provided by the Pipeline;
- an Internal Rate of Return (IRR) approach where the Total Revenue will produce a forecast IRR consistent with the principles in sections 8.30 and 8.31 of the Access Code; and
- a Net Present Value (NPV) approach whereby the Total Revenue will produce a forecast NPV of zero. The NPV approach should use a discount rate that provides the Service Provider with a return consistent with the principles in sections 8.30 and 8.31 of the Access Code.

Section 8.4 also provides that the methodology used to calculate the Cost of Service, IRR or NPV should be in accordance with generally accepted industry practice. Section 8.6 provides that a range of values may be attributed to the Total Revenue and that the Regulator may have regard to performance indicators to determine a level of costs within this range.

5.2. Compliance

In accordance with section 8.4 of the Access Code, Envestra has adopted a Cost of Service approach in the calculation of the Total Revenue requirement. The Total Revenue requirement is made up of:

- revenue from the provision of Haulage Reference Services. This revenue comprises a return on the Distribution System assets attributable to the provision of Haulage Reference Services, depreciation on those assets, plus Non-Capital Costs;
- revenue from the provision of Ancillary Reference Services. This revenue represents a recovery of costs for the provision of these Services; and
- revenue from the provision of Negotiated Services

and is established using the formula below:

$$TR = (AV*WACC) + D + NCC + ECM + (WC*\text{nominal } WACC) + CT$$

where

TR = Total Revenue

AV = average Capital Base value

WACC = weighted average cost of capital

D = depreciation

NCC = Non-Capital costs

ECM = efficiency carryover mechanism

WC = working capital

CT = cost of tax

The Total Revenue to be derived annually from the provision of Services is based on:

- a Capital Base of $683.3m as at 1 January 2003, adjusted each year for:
  - forecast New Facilities Investment (see section 10 of this Access Arrangement Information);
  - depreciation calculated on a straight-line basis (section 8);
  - forecast Redundant Capital (section 6); and
  - inflation (Section 6).
- a real post-tax rate of return of 7.9% (section 7);
- Non-Capital Costs (section 9);
- efficiency carryover (section 12);
- Cost of Working Capital (section 9); and
- Cost of tax (section 11).

The New Facilities Investment and Non-Capital Costs used in the above formula exclude costs associated with the provision of excluded services, as discussed in section 9.3.

Each of these matters is discussed in more detail in the referenced sections.

6. CAPITAL BASE

The approach for rolling forward the Capital Base from 1 January 1998 to 1 January 2003 is set out in the Fixed Principle contained in Clause 9.2(b)(3) of the Victorian Gas Industry Tariff Order 1998 (the 'Tariff Order'):

This method is summarized as follows:

The value of the Capital Base as at 1 January 1998 (Initial Capital Base)
Plus 50% of New Facilities Investment over the First Access Arrangement Period, net of Capital Contributions
Less 50% of regulatory depreciation over the First Access Arrangement Period
Plus CPI escalation
Plus 50% New Facilities Investment over the First Access Arrangement Period, net of Capital Contributions
Less 50% of regulatory depreciation over the First Access Arrangement Period
Less Redundant Capital
Less Asset Disposals

The process used by Envestra to roll forward the Capital Base, which is consistent with the Fixed Principle requirement, is described below.

Initial Capital Base

The Initial Capital Base ($580.0m) was determined when the Access Arrangement was approved in 1998.

New Facilities Investment over the First Access Arrangement Period

Gross New Facilities Investment over the period 1998 to 2002 is set out below. Actual expenditure is provided for 1998 to 2001. Capital expenditure for 2002 is set at the forecast approved by the Regulator in 1998.

Gross New Facilities Investment ($m)	1998	1999	2000	2001	2002
Mains	14.4	10.9	7.8	9.1	14.0
Inlets	11.4	12.1	11.3	10.7	11.6
Meters	4.1	5.0	5.9	6.7	4.1
Telemetry	0.0	0.0	0.0	0.1	0.2
Other Distribution Equipment	2.4	0.3	0.2	0.1	0.5
IT Systems	1.7	0.0	3.3	1.6	0.0
Other	0.4	0.7	0.2	0.1	0.0
TOTAL	34.5	29.1	28.7	28.6	30.4

Table 11 Gross New Facilities Investment 1998-2002

Envestra has commercial incentives to ensure that expenditure is prudent, and specifically has the incentive to:

- minimise expenditure – under a price cap regime, lower expenditure implies higher profits, which means that a Service Provider is discouraged from "gold plating" or unnecessary expenditure;
- apply Surcharges where a project would be uneconomic – higher Surcharges increase profit, so a Service Provider has an incentive to levy surcharges where permitted. As a Service Provider is permitted to levy a Surcharge for that part of the project cost that does not pass the Economic Feasibility Test, it is possible to infer that the remaining expenditure passes the Economic Feasibility Test, and can be included in the Capital Base.

Accordingly, Envestra submits that the New Facilities Investment in the First Access Arrangement Period has satisfied the requirements of the Access Code (section 8.16) and should therefore be rolled in to the Capital.

To derive net New Facilities Investment for the purpose of rolling forward the Capital Base, it is necessary to deduct Capital Contributions and excluded capital expenditure from gross New Facilities Investment. Net New Facilities Investment is set out in the following table.

Net New Facilities Investment ($m)	1998	1999	2000	2001	2002
Gross New Facilities Investment	34.5	29.1	28.7	28.6	30.4
Less: Capital Contributions	0.0	1.0	0.6	0.2	0.6
Less: Excluded Capital Expenditure					
Mains Alterations	0.0	0.2	0.9	0.6	0.4
Tariff D Capital Expenditure	0.2	0.5	2.2	1.5	0.8
Net New Facilities Investment	34.3	27.5	24.9	26.3	28.6

Table 12 Net New Facilities Investment 1998 - 2002

Regulatory Depreciation over the First Access Arrangement Period

Regulatory depreciation over the First Access Arrangement Period has been set equal to the depreciation approved by the Regulator in 1998 as proposed by the Regulator[6].

The amount used for depreciation in bringing forward the Capital Base is:

Depreciation ($m)	**1998**	**1999**	**2000**	**2001**	**2002**
Regulatory Depreciation	17.9	19.9	21.7	23.7	25.8

Table 13 Regulatory Depreciation 1998- 2002

Redundant Capital

Envestra is not aware of any material assets that have become redundant over the First Access Arrangement Period. Therefore no Redundant Capital has been deducted in rolling forward the Capital Base.

Disposals

The original DORC valuation was used to determine which of the assets sold during the period were included in the Initial Capital Base. Only one property included in the Initial Capital Base has been disposed of. This asset had a value of $0.57m in the Capital Base in June 2000.

CPI

Fixed Principle 9.2(b)(3) requires the Capital Base to be adjusted by CPI, where the CPI is defined as the All Groups Consumer Price Index for the Eight State Capitals for the September quarter before the start of that year.

Using the assumptions outlined above, the Initial Capital Base has been rolled forward to December 2002 in accordance with the Regulator's preferred method as follows:

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[6] ORG Consultation Paper, May 2001

Capital Base ($m)	1998	1999	2000	2001	2002
Opening Asset Value	580.0	594.4	610.0	623.2	663.8
50% Net New Facilities Investment	17.1	13.7	12.5	13.1	14.3
50% Depreciation	(8.9)	(10.0)	(10.9)	(11.8)	(12.9)
Asset Sales/Disposals	0.0	0.0	(0.6)	0.0	0.0
CPI Escalation	(2.0)	8.0	10.6	38.0	16.8
50% Net New Facilities Investment	17.1	13.7	12.5	13.1	14.3
50% Depreciation	(8.9)	(10.0)	(10.9)	(11.8)	(12.9)
Closing Asset Value	594.4	610.0	623.2	663.8	683.3
Average Asset Value	587.2	602.2	616.2	643.5	673.5

Table 14 Roll forward of the Capital Base 1998 – 2002

7. COST OF CAPITAL

7.1. Access Code Requirements

Section 8.30 of the Access Code requires that the Rate of Return used in determining a Reference Tariff provide a return that is commensurate with market conditions for funds and the risk of delivering the Reference Service.

Section 8.31 provides that the Rate of Return may be based on a weighted average of the return applicable to each separate funding source (for example, debt and equity) and that the returns may be determined using a well-accepted financial model such as the Capital Asset Pricing Model (CAPM). This section also provides that, in general, the weighted average return on funds should be calculated by reference to a financing structure that reflects standard industry structures.

7.2. Compliance

In the 1998 Final Decision, the Regulator determined the cost of capital to be a real pre-tax rate of 7.75%. However in *Consultation Paper No 1*, the Regulator recommended that a post-tax real WACC be used to determine the cost of capital.

Envestra believes that a real pre-tax cost of capital is more consistent with the Access Code than the real post-tax approach proposed by the Regulator. Arguments supporting a real pre-tax approach were set out in Envestra's response to the Regulator's *Position Paper* released on 7 September 2001. The Regulator obviously has fixed views on this issue and has shown it is not prepared to consider arguments for an alternate position.

Envestra therefore presents parameter values in the real post-tax format requested by the Regulator. Envestra has determined that it requires a real post-tax WACC of 7.9% for the Distribution System to provide a rate of return commensurate with the risks incurred by the business, taking into account prevailing market conditions. A detailed analysis of the approach and assumptions used in determining this figure is provided in Attachment A to this document. Separate documentation on the value of imputation credits (gamma) is set out in Attachment B. Following is a summary of the input parameters for the WACC calculation.

WACC parameters	Value
Expected Inflation (for WACC)	2.50%
Debt	60%
Equity	40%
Risk Free Rate	6.1%
Asset Beta	0.54
Equity Beta	1.16
Market Risk Premium	7.30%
Debt Margin	1.65%
Real Post-Tax WACC	7.9%

Table 15 WACC Parameters

8. FORECAST DEPRECIATION

8.1. Access Code Requirements

Section 8.33 of the Access Code requires that the Depreciation Schedule be designed:

- so as to result in the Reference Tariff changing over time in a manner consistent with the growth of the market for the Services provided by the Pipeline;
- so that each asset or group of assets is depreciated over the economic life of that asset or group of assets;
- so that, to the maximum extent reasonable, the depreciation schedule is adjusted over the life of an asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and
- so that an asset is depreciated only once.

8.2. Compliance

Envestra has used a straight-line approach to depreciation based on the asset lives adopted in deriving the Initial Capital Base. This is consistent with the requirements of the Access Code.

In particular, the straight-line approach ensures that:

- depreciation is allocated over the entire useful lives of the Distribution System assets; and
- depreciation is consistent with the stable growth in demand that is forecast to occur over the Access Arrangement Period.

The straight-line approach also has the advantage of being:

- readily understandable;
- transparent; and
- easily capable of being replicated on an ongoing basis.

Envestra notes that the straight-line approach to depreciation has also been adopted by other regulated gas businesses and has been accepted by regulators throughout Australia.

The economic useful life (EUL) of each asset type is shown in the following table. These EULs are used to calculate the depreciation charge for new facilities installed from 1998.

Asset Categories	EUL (yrs)
Mains and Inlets	60
Meters	25
Telemetry	5
Other Distribution Equipment	50
IT Systems	5
Other	10

Table 16 Asset Lives (years) for Distribution System Assets

Asset Remaining Lives (RL)

For the purposes of determining Total Revenue, individual asset categories in the Initial Capital Base were grouped together to calculate depreciation and return on assets. The weighted average remaining life for each of the asset groupings is set out in the following table. These RLs are used to calculate the depreciation charge for assets installed before 1998.

Asset Categories	RL (yrs)
Mains and Inlets	37
Meters	13
Equipment, Vehicles & Other	0
Land & Buildings	31

Table 17 Average Remaining Life by Asset Category as at 1 Jan 2003

Forecast Depreciation by Category

The following table shows the calculated depreciation over the Second Access Arrangement Period for each category of asset.

Total Depreciation ($m)	2003	2004	2005	2006	2007
Mains & Inlets	15.8	16.5	17.3	18.2	19.1
Meters	5.6	5.9	6.4	6.9	7.5
Land & Buildings	0.3	0.3	0.3	0.4	0.4
Telemetry	0.1	0.1	0.1	0.1	0.1
Other Distribution Equipment	0.1	0.1	0.1	0.2	0.2
IT Systems	1.3	1.1	0.7	0.2	0.0
Equipment, Vehicle & Other	0.2	0.2	0.2	0.2	0.2
TOTAL	23.3	24.3	25.3	26.1	27.4

Table 18 Forecast Depreciation

9. NON-CAPITAL COSTS

9.1. Access Code Requirements

Section 8.36 of the Access Code defines Non-Capital Costs as being the operating, maintenance and other costs incurred in the delivery of a Reference Service.

Section 8.37 of the Access Code provides that Reference Tariffs may provide for the recovery of all Non-Capital Costs (or forecast Non-Capital Costs) except for those that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering Reference Services.

Pursuant to section 8.2(e) of the Access Code, any forecasts for Non-Capital Costs must represent best estimates arrived at on a reasonable basis.

9.2. Compliance

Forecasts of Non-Capital Costs have been developed taking into account changes anticipated in the cost of managing and operating the Distribution System.

Real reductions in Non-Capital Costs between 2003 and 2007 are forecast despite increasing customer numbers, reflecting forecast increases in labour productivity and cost reductions.

Envestra engaged Pacific Economics Group to conduct a benchmarking study examining the performance of the business relative to other natural gas distribution businesses. The results confirmed that Envestra's operating costs were well below the average for the sample included in the analysis ie. the forecasts provided in this proposal are those that would be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, to achieve the lowest sustainable cost of delivering Reference Services.

Non-Capital Costs have been grouped into the following categories:

9.3. Operating Costs

Operating costs are the costs of operating and maintaining the Distribution System. These costs have been broken into a number of groups as described below.

Network maintenance & repairs

- Network maintenance – costs associated with city gate maintenance and calibration, analytical laboratory services and regulator maintenance;
- Leak repairs – costs associated with surveying, classifying and repairing

gas leaks;

- Operations administration – costs associated with administrative support for maintenance and repair activities (includes dedicated operational administration staff and their associated infrastructure such as information systems);
- Inventory management for operational functions;
- Fleet management;
- Network services – costs associated with economic evaluation of network growth opportunities;
- One-call centre – costs associated with providing a call centre service to the public on all matters associated with the network including asset location service and costs associated with meter turn-ons/offs;
- Operations management – costs associated with managing the network operational functions including budget management, management information and reporting; and
- Property management – costs associated with the management of operational properties.

Cathodic protection

- Costs associated with maintaining cathodic protection for network assets.

Technical services

- Network engineering – costs associated with the development of safety and operational policies for the network, consulting on network design and operation and representing Envestra’s interests on distribution system standards and development;
- Environmental management – costs associated with coordinating corporate environmental policies, liasing with government agencies, and managing corporate environmental reporting;
- Technical assurance – costs associated with the installation and maintenance of equipment to comply with legislative and safety requirements;
- Subscription to standards and code preparations bodies; and
- Meter set design – costs associated with meter and regulator set designs and for providing technical advice (internally and externally) on design and combustion issues.

Planning and control

- Gas control - costs associated with managing effective gas control systems and processes for the network;
- Electronics and instrumentation – costs associated with the calibration and repairs of electronic and instrumentation equipment utilised in the field by network personnel and on remote metering and telemetry equipment; and
- Network planning – operating costs associated with the planning and system design of the reticulation network.

Administration and General Costs

Finance including:

- accounting, management reporting and operational analysis costs;
- audit fees;
- accounts receivable and billing;
- licence fees; and
- accounts payable and financial reporting.

Customer Service

- providing information to customers as provided in the Terms and Conditions and funding activities associated with the Ombudsman arrangements implemented by the Government.

Human Resource Management and Administration Including

- policy development and monitoring, payroll, recruitment and HR consultancy; and
- health and safety – costs associated with developing and reviewing OH&S policies and procedures and ensuring that legal requirements are met.

Information Technology Associated With Corporate Functions.

Regulatory functions

- preparing and administering access arrangements;
- regulatory reporting and compliance; and
- preparation of safety cases and reports.

Other corporate costs, including

- insurance premiums for the network assets, public liability and employee-related insurance costs;
- general management and administration;
- procurement;
- rental and property management costs associated with corporate functions; and
- strategic development and planning.

Network Marketing Costs

Network Marketing costs are those costs that are incurred to maintain and grow volumes distributed via the network. They include expenditure on the following activities:

- advertising to promote utilisation of natural gas;
- advertising to increase consumer awareness of gas applications and appliances;
- provision of direct advice on the utilisation and application of gas to key Customer influencers such as builders, engineers and plumbers;
- the establishment and ongoing support of gas appliance penetration into homes and businesses; and
- the development of new applications for gas (eg micro-generation, gas as a vehicular fuel).

A detailed confidential network marketing plan will be provided to the Regulator providing the rationale for this expenditure.

Property taxes – property-related taxes.

Non Capital Costs Summary ($m)	2003	2004	2005	2006	2007
Operating costs					
Network maintenance & repairs	22.7	22.9	23.4	24.1	24.7
Cathodic protection	0.6	0.6	0.6	0.6	0.7
Technical services	1.3	1.4	1.4	1.4	1.5
Planning and control	1.1	1.1	1.2	1.2	1.2
Total operating costs	25.8	26.0	26.6	27.3	28.0
Administration and general costs					
Finance	3.5	3.6	3.7	3.9	4.0
Customer Service	0.5	0.5	0.5	0.5	0.6
Human resources	1.0	1.0	1.0	1.1	1.1
Information technology	1.3	1.3	1.3	1.3	1.4
Regulatory	1.0	1.1	1.1	1.6	2.2
Other corporate costs	7.8	8.0	8.2	8.4	8.6
Total administration costs	15.1	15.5	15.9	16.8	17.7
Network marketing costs	**2.7**	**2.8**	**2.9**	**2.9**	**3.0**
Property taxes	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**
TOTAL NON-CAPITAL COSTS	**43.8**	**44.5**	**45.6**	**47.3**	**49.0**

Table 19: Forecast Non-Capital Costs 2003 - 2007

Unaccounted for Gas (UAG)

Envestra has not included any costs in relation to UAG in its Access Arrangement, in anticipation that target levels of UAG will be met. UAG is Gas that is ‘lost’ or unaccounted for in the Distribution System, predominantly due to leakage and metering tolerances. There are no compressors used in the Distribution System and therefore there is no compressor fuel use.

The Regulator has determined an allowable level of UAG in the Distribution System (see the Distribution System Code) based on percentage of gas throughput. This is as follows:

UAG (%)	Customer <250 TJ/yr	Customer >=250 TJ/yr
	2.9	0.3

Table 20: UAG Benchmark

The procedures of payment for UAG in the First Access Arrangement Period will apply for the Second Access Arrangement Period 2003 to 2007. As part of the settlement process, Users will automatically pay for UAG (since Users pay for all gas taken at custody transfer points). At the end of each year, where it is determined (by VENCorp) that a User has paid for a quantity of UAG that exceeds the benchmark UAG, Envestra will be required to compensate the User for that difference. Where the actual UAG has been determined to be less than the benchmark UAG, the User will pay Envestra the difference.

Full Retail Contestability (FRC) Costs

Costs have been excluded from the Non-Capital Cost Forecasts in this Access Arrangement. Forecasts of FRC costs will be provided to the Regulator in a separate submission under the Order in Council pursuant to the Gas Industry Act. Envestra understands that the Regulator will approve charges under the Order in Council to enable Envestra to fully recover these costs. Ongoing operational costs associated with FRC will be rolled into the cost forecasts for the third Access Arrangement Period.

Adjustments for Changes in Scope and Cost Structures

The cost forecasts reflect changes in scope and cost structure over the First Access Arrangement Period as outlined below:

- Non-Capital Costs have been increased to reflect a change in capitalisation policy (an offsetting adjustment has also been included in forecasts of New Facilities Investment which are provided in Section 10).

- The Government advised on 22 February 2002 that licence fees would increase by 260% and be backdated to 1 July 2001. Non-Capital Cost forecasts have been increased accordingly.

- The Distribution System has experienced a superannuation ‘holiday’ for the past 2 years that will end in June 2002. In addition, the minimum employer contribution will increase to 9% from 1 July 2002.

- Insurance premiums are expected to rise in 2002/03 following increased ‘tightness’ in the international insurance market.

- Envestra anticipates that gas distribution businesses will have increased customer service responsibilities in the Second Access Arrangement Period eg. participation in the Ombudsman Scheme, information provision requirements.

- Network marketing costs have been increased in line with the (confidential) network marketing strategy submitted to the Regulator.

- GPU GasNet has advised that pressure in the transmission pipeline will be downgraded in 2005 and that transmission connection charges will increase from 2006 and 2007.

These adjustments are reflected in the Non-Capital Costs forecast in Table 19.

9.4 Excluded Services

Envestra provides a number of 'excluded' services including meter management services to Tariff D consumers and other services for third parties. Expenditure associated with these activities has varied from year to year as shown in the following table.

Excluded Services ($m)	1999	2000	2001	Average
Third Party Repairs	0.5	0.5	0.2	0.4
Alter meter positions	0.1	0.1	0.1	0.1
Tariff D Meter O&M charges	0.4	0.6	0.9	0.6
Other revenue	0.0	0.1	0.5	0.2
Total	**1.1**	**1.3**	**1.7**	**1.4**

Table 21 Expenditure on Excluded Services

For the purposes of determining Total Revenue, Envestra has excluded the operational costs associated with excluded services. These are expected to be $1.4 million per annum, equivalent to the average expenditure incurred in providing the services for the period 1999 to 2001.

9.5. Cost of Working Capital

An allowance for the cost of working capital employed in providing Reference Services has been included in the forecast total cost used to determine the target revenue.

The method used by Envestra to calculate working capital is analogous to that used by the Independent Pricing and Regulatory Tribunal (IPART) in its 2000 Decision on AGLN's distribution network. The method recognises that total revenue forecasts obtained by applying the cost of service model are accrued amounts. The cost of service model therefore incorrectly ignores the intra-year cash flow timing differences associated with demand seasonality, revenue and expenditure mismatches and lags between billing and receipt of revenue. Correct treatment of these cashflow timing differences generates a working capital requirements shown in the following table.

Cost of Working Capital		**2003**	**2004**	**2005**	**2006**	**2007**
Reference Tariff Revenue		119.3	129.7	140.6	152.7	166.0
Non-Capital Costs	**Days**	43.9	44.5	45.6	47.3	49.0
Debtors	14	(4.6)	(5.0)	(5.4)	(5.9)	(6.4)
Unbilled Gas	30	(9.8)	(10.7)	(11.6)	(12.6)	(13.6)
Inventories	0	0.0	0.0	0.0	0.0	0.0
Prepayment	0	0.0	0.0	0.0	0.0	0.0
Creditors	30	0.4	0.4	0.4	0.5	0.5
Net Cost of Working Capital		(14.0)	(15.2)	(16.5)	(17.9)	(19.5)
Cost of Working Capital ($m)		1.5	1.6	1.8	1.9	2.1

Table 22 Cost of Working Capital

The cost of working capital has been determined after taking into account Envestra's expenditure and revenue profiles as set out in the above table. The cost of working capital has been calculated by applying the real post-tax WACC, adjusted for inflation, to an estimated working capital requirement calculated for each year of the Access Arrangement Period. Inclusion of an allowance for working capital is consistent with regulatory decisions handed down by IPART, OffGAR and the QCA for electricity and/or gas distribution networks.

10. NEW FACILITIES INVESTMENT

10.1. Access Code Requirements

Section 8.20 of the Access Code provides that Reference Tariffs may reflect the value of New Facilities Investment forecast to occur within the Access Arrangement Period. In order to do so, this investment must reasonably be expected to pass the requirements of section 8.16(a) and (b) of the Access Code when it is forecast to occur.

Section 8.16 requires New Facilities Investment:

- not to exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services; and
- to meet one of the following criteria:
  - the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or
  - the New Facility has system-wide benefits that justify a higher Reference Tariff; or
  - the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

In accordance with section 8.2(e) of the Access Code, forecasts of New Facilities Investment must also represent best estimates arrived at on a reasonable basis.

10.2. Compliance

New Facilities Investment forecast to occur within the Second Access Arrangement Period is based on the forecast level of capital expenditure required to allow Envestra to meet the forecast growth in demand for haulage Services and to meet system augmentation and replacement requirements.

New Facilities Investment forecast for the Second Access Arrangement Period has been divided into two categories:

- Growth Capital – capital required to extend the Distribution System into new areas (eg new subdivisions).
- Replacement Capital – capital required to maintain the integrity of the Distribution System (eg replace pipes, meters etc).

Costs associated with introducing full retail contestability have been excluded from the New Facilities Investment forecasts as these are to be recovered via the Order in Council pursuant to the Gas Industry Act. To the extent that these costs have not been recovered by the end of the Access Arrangement Period, they will be rolled into the cost forecasts from 2008 at the prevailing WACC.

The New Facilities Investment forecast is provided in the following table.

New Facilities ($m)	2003	2004	2005	2006	2007
Growth					
Mains/inlets/meters	18.8	18.8	20.6	22.4	22.5
Other	1.5	1.4	2.7	2.7	1.0
Total Growth	20.3	20.2	23.3	25.1	23.5
Replacement					
Mains/Inlets	5.8	5.9	6.0	6.2	6.3
Periodic meter changes	0.8	4.8	5.7	5.6	6.9
Other	0.6	0.5	0.3	0.3	0.3
Total replacement	7.2	11.2	12.0	12.0	13.5
Total New Facilities	**27.5**	**31.4**	**35.4**	**37.1**	**37.0**

Table 23 Forecast New Facilities Investment 2003-2007

Growth capital is presented under the following headings:

Mains/Inlets/Meters

Expenditure on mains, inlets and meters is required to connect new customers to the Distribution System over the Access Arrangement Period. The forecast expenditure is based on Envestra's demand forecasts for the Access Arrangement Period, which are discussed in section 22 of this document.

Other

Other categories of growth expenditure in New Facilities Investment includes:

- Field Regulators
  Forecast field regulator costs are derived from operational plans developed to maintain a satisfactory supply and control of gas transported in the network. It is expected that during the Second Access Arrangement Period, regulators in Eltham, Bundoora, Mill Park, Rosebud, Langwarrin, and McCrae will be upgraded.

- Improve Supply
  Forecasts are derived from operational plans projecting enhancements required to maintain quality of supply. Significant expenditure is expected in 2003 and 2004 on high pressure systems in Morwell, Berwick, Rosebud and Cranbourne.

- Reticulations to New Towns
  The forecasts contain an allowance of $1.7 million for reticulation of a new town in 2005 and 2006. Economic analysis undertaken by Envestra indicates that this reticulation will pass the Economic Feasibility Test in section 8.16 of the Access Code.

Replacement capital is required to replace aging parts of the existing system. This expenditure is categorised into the following:

Mains/Inlet Replacement

The focus of the replacement program is to replace aged cast iron and uncoated steel mains and services primarily in the Central Zone. An analysis of system failure mode was conducted in 1997 and this study identified an approximate mains failure length per year. The initial asset management plan indicated that if less than 20km per year was renewed, then there would need to be a "ramping up" of mains renewal length to over 40km/year by the year 2010. In 1998, it was decided that prudent asset management required that the renewal rate be increased to 25 to 30km of mains per year. This rate of replacement underpins the forecast expenditure.

Periodic Meter Changes

Meters are replaced according to the age profile of each meter 'family' installed. Estimates of meters to be replaced each year have been derived on the existing age profile of meters. The number of meters replaced is expected to increase over the Access Arrangement Period in line with the meter age profile. As a consequence, meter replacement expenditure will increase from $0.8 million in 2003 to $6.9 million in 2007.

Meter replacement is highly dependent upon the ongoing successful use of sampling techniques. If a meter family were to fail the sampling tests, additional capital expenditure would be incurred ahead of that planned.

Other

Other replacement expenditure includes upgrading telemetry and purchases of miscellaneous plant and equipment. Operational plans show that expenditure on telemetry and plant will be highest in 2003 and 2004.

11. COST OF TAX

11.1. Introduction

The Regulator has proposed to calculate the rate of return on assets using the 'vanilla' post-tax approach to WACC. This approach requires the Regulator to include an allowance for corporate taxation in the cash flows for Envestra (i.e. the cost of tax or Tax Wedge). To this end the Regulator has determined that the Cost of tax estimate be "unbiased" and consistent with a competitive market outcome and the other benchmark assumptions with regard to gearing, interest costs and tax depreciation. The approach used by Envestra to calculate the cost of tax is described in this section.

The calculation of cost of tax is circular, as cost of tax is both a function of and a component of revenue. The calculation therefore requires a preliminary calculation which excludes cost of tax from revenue. This is then grossed up to derive a cost of tax based on revenue inclusive of Cost of tax.

The table below outlines the Cost of tax calculation more clearly:

	Cost of Service CRR *excluding* cost of tax
Plus	Customer Contributions
Less	Non-Capital Costs
Less	Tax Depreciation
Less	Interest Expense
Equals	Net Income Excluding Cost of tax
Multiplied by	Tax rate
Equals	Tax Expense
Divided by	1 – Tax Rate
Equals	**Cost of tax**

Table 24 Cost of Tax Calculation

11.2. Tax Depreciation

Under the post-tax approach to the cost of capital an estimate of the Cost of tax must be incorporated into the cost reflective revenue. To this end the Regulator has indicated that it is seeking to estimate an 'unbiased' Cost of tax for each of the distribution businesses based on the 30 June 1996 Previously Audited Book Value and the capital expenditure that has occurred since that time through to 31 December 2007.

Section 8.33 of the Access Code provides guidance as to the appropriate approach to formulating depreciation, and requires that:

- Reference Tariff changes over time are consistent with the growth of the market for Services;

- each asset is depreciated over the economic life of that asset; and
- to the maximum extent reasonable, the depreciation schedule is adjusted over the life of the asset to reflect changes in the expected economic life of the asset.

In establishing an unbiased estimate of the cost of tax *all* stakeholders' perspectives must be taken into account and it must not systematically over/underestimate the expected cost over the long term. Envestra has calculated the cost of tax using effective life tax depreciation and not accelerated depreciation. This approach has been adopted because Envestra believes that parameters used to derive the cost of tax in Regulatory determinations must not:

a) Subvert government policy objectives

The use of accelerated rates of tax depreciation for the purpose of setting benchmark revenue undermines Government Fiscal Policy that was designed to encourage investment and stem the net outflow of capital from Australia. The former Federal Government implemented a regime of accelerated depreciation, which was announced in its "One Nation" Statement of 26 February 1992. The adoption of accelerated depreciation was specifically designed to counter the un-competitive taxation of long-lived assets in Australia compared with some OECD and Asian countries.

The policy intent of introducing accelerated depreciation in Australia is described in the statement as follows:

"This acceleration of the depreciation schedules has the effect of substantially reducing the effective tax rate on domestic investment in plant and equipment

The tax preference for domestic plant and equipment will encourage such investment relative to alternatives, including, foreign investment by Australian companies."

It is evident that investors in plant and equipment were the intended beneficiaries of this policy because if the benefit of accelerated depreciation was passed through to the consumer the objective of encouraging investment in Australia would not be achieved. However, consumers did benefit from the increased provision of services that otherwise would not have occurred. Regulators must not overstep their mandate and distort government's macroeconomic management of the economy in making their determinations. Effective life tax depreciation is consistent with the objectives of Fiscal Policy.

b) Retrospectively disadvantage investors

Expected returns from investments made that incorporated accelerated rates of tax depreciation would be reduced if the timing effects of accelerated depreciation were passed through to consumers. This is a risk unique to regulated businesses and, if the Regulator chose to act in this manner, would be harmful to Envestra's legitimate business interests and investment in the Distribution System. Furthermore, such action would significantly increase the risks and required rates of return associated with gas infrastructure investment in Victoria. Any short-term gains to consumers, in the form of slightly lower prices, would be minor relative to the value at risk over the medium to long term via the reduced provision of services, as confirmed by the Productivity Commission[7].

c) Temporally distort Reference Tariff pricing

The Regulator's price control model calculates tax liabilities for the years 2003 to 2007. Under an accelerated depreciation assumption, the tax profile generated by the price control model shows small tax liabilities in the early years, but which increase with time. These tax liabilities become quite significant beyond 2007. Under the Regulator's approach, this increased cost of tax must be passed on to the consumer. This will result in significant tariff increases in the third and subsequent Access Arrangement Periods.

Effective life depreciation normalises the tax depreciation profile, resulting in Reference Tariffs that change according to market growth, and not due to other transitory factors that can distort pricing and demand (e.g. accelerated depreciation). The ACCC has endorsed normalisation for reasons including the avoidance of price volatility[8]. Effective life depreciation is therefore consistent with the Access Code and ACCC principles.

Envestra is of the view that the Cost of tax should be calculated using effective life depreciation, as this more appropriately recognises the tax wedge over the life of the asset and hence avoids revenue and price volatility in the face of changes in tax liabilities. Envestra has used effective life tax depreciation rates based on allowable rates published by the Australian Taxation Office.

Effective life tax depreciation fulfils the requirements of the Access Code, is unbiased from the viewpoint of *all* stakeholders and avoids the inter-generational pricing inequities brought about by other less suitable methodologies. Moreover, Envestra's tax depreciation is forward looking and consistent with the philosophy employed by the ACCC and its desired outcomes from the regulatory regime.

The 30 June 1996 Previously Audited Book Value (PABV), effective lives and depreciation methodology for each of the assets are set out in the following table.

[7] Productivity Commission, *2000-01 Annual Report*, pp 4-16

[8] ACCC, *Post-tax revenue handbook*, October 2001

Asset category	1996 PABV ($m)	Effective Life (yrs)	Depreciation Method
Mains	259.8	50.0	DVM
Services	161.1	20.0	DVM
Meters	45.0	25.0	DVM
Other Distribution System Assets	31.1	33.0	DVM
SCADA & Telemetry	1.9	5.0	DVM
Plant and Equipment	2.2	10.0	DVM
Buildings	3.8	18.0	SL
	504.9		

Table 25 1996 Previously Audited Book Value, Effective Life and Depreciation Method

11.3. The Value of Imputation Credits

The post-tax approach to the cost of capital requires an explicit allowance for the Cost of tax in the cost reflective revenue. Academics and regulators typically deal with the effect of dividend imputation through the Cost of tax as they contend that corporate income tax payments represent a pre-payment of personal tax. The value of imputation credits (gamma) is a function of:

(a) imputation credits distributed by the firm;

(b) the proportion of their face value received by shareholders; and

(c) complementary and offsetting reforms on equity taxation introduced with the dividend imputation system.

The Cost of tax incorporates an adjustment for the value of imputation credits so that investors achieve the regulated cost of capital. Incorrectly valuing imputation credits will result in a biased Cost of tax, which will distort pricing, demand and incentives on distribution businesses.

Having examined recent empirical evidence, economic theory and the history of dividend imputation Envestra is of the view that dividend imputation reduces the tax payable to only a very narrow class of investors. However, counteracting this are the other equity related tax changes (e.g. CGT) implemented with dividend imputation. The net result is that the overall level of tax payable on equity investments post-imputation may be higher relative to pre-imputation implying the value of gamma is negative. Moreover, the recipients of imputation credits (namely domestic shareholders) are not the cost of capital price setters in Australia. It is foreign investors, who do not benefit from the dividend imputation system, that determine the cost of capital for firms such as energy distribution businesses.

The weight of evidence supports a value of gamma of zero. Hence, to maintain consistency with the other market based parameters used in its submission and to provide an unbiased estimate of the Cost of tax, Envestra has used a gamma of zero.

Further justification for the use of a gamma value of zero is set out in Attachment B.

The Cost of tax calculation is show below for 2003-07.

Cost of Tax $m	**2003**	**2004**	**2005**	**2006**	**2007**
Revenue requirement	123.9	127.6	131.8	126.8	142.2
Capital Contributions	1.7	1.8	1.0	1.0	1.1
Non-Capital Costs	43.9	44.5	45.6	47.3	49.5
Tax depreciation	31.2	31.1	31.1	31.4	31.8
Interest Expense	33.4	34.5	35.9	37.4	38.8
Net income excluding Cost of tax	17.1	19.2	20.2	21.7	23.6
Tax payable	7.3	8.2	8.7	9.3	10.1
Franking credit	0.0	0.0	0.0	0.0	0.0
Cost of Tax	**7.3**	**8.2**	**8.7**	**9.3**	**10.1**

Table 27 Cost of Tax forecast

12. EFFICIENCY CARRYOVER

12.1. Access Code Requirements

Section 8.44 of the Access Code provides that the Reference Tariff Policy may include an Incentive Mechanism that permits the Service Provider to retain all or a share of returns that exceed those forecast at the commencement of an Access Arrangement Period.

Section 8.46 requires an Incentive Mechanism to be designed with a view to achieving the following objectives:

(a) to provide the Service Provider with an incentive to increase the volume of sales of all Services, but to avoid providing an artificial incentive to favour the sale of one Service over another;

(b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(c) to provide the Service Provider with an incentive to develop new Services in response to the needs of the market for Services;

(d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non Capital Costs, and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non Capital Costs for the purposes of sections 8.16 and 8.37; and

(e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation or volume of sales occur).

12.2. The Efficiency Sharing Mechanism Adopted by Envestra

The efficiency carryover mechanism adopted by Envestra has many of the attributes of the model proposed by the Regulator. However, Envestra's model incorporates two improvements over the approach proposed by the Regulator. These are:

- the efficiency carryover mechanism will apply for ten years, not five; and
- there will be no negative carryovers arising out of the First Access Arrangement Period.

Further details of the mechanism are provided in section 15.4.

12.3. Quantifying the Efficiency Gain

To calculate the efficiency gain for the First Access Arrangement Period actual Non-Capital Costs and New Facilities Investment have been converted into 1998 dollars using the inflation rate assumed in the Final Decision (2% in 1998 and 2.5% thereafter). The 1998 dollar actuals and benchmarks have then been converted to July 2001 constant dollars. Efficiency gains and losses have been calculated from the July 2001 constant dollars benchmarks as per the table below.

Under the approach adopted only incremental gains greater than those assumed in the benchmarks are rewarded under the Regulator's efficiency carryover mechanism, which is summarised as:

Benchmark_t
Minus
Actual
Equals
Underspend_t
Minus
Underspend_{t-1}
Equals
Incremental gain

The incremental gain for capex is multiplied by the real pre-tax WACC to provide the amount that is allowed as an efficiency carryover. The incremental gain or loss in period *t* is carried forward for ten years from year *t* + 1. Positive and negative efficiency carryovers for Non-Capital Costs and New Facilities Investment in each year are summed with only the net amount included as an efficiency carryover revenue increment. Below is the mechanics of the efficiency carryover for Non-Capital Costs and New Facilities Investment.

Efficiency Carry-over ($m)	**2003**	**2004**	**2005**	**2006**	**2007**
Non-Capital Costs	(4.0)	(4.0)	(4.2)	(4.3)	(4.4)
New Facilities Investment	0.4	0.4	0.5	0.5	0.5
Total Efficiency Carry-over	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)
Efficiency Carry-over for Determining Revenue Requirement	0.0	0.0	0.0	0.0	0.0

Table 28 Calculation of Efficiency Carry-over 2003 - 2007

xlxl

[6] ORG Final Decision 1998, p96.

The above calculations yield a negative efficiency carry over for the period 2003 to 2007. This negative carryover is based on Non-Capital Costs and New Facilities Investment, which have not been adjusted for changes in scope and output. However, to the extent that new connection numbers and volumes were less than forecast in 1998, any such adjustments will reduce the carryover even further. Consistent with the principle of “no negative carry-overs” for the First Access Arrangement Period, the efficiency sharing mechanism has been set to zero in determining the revenue requirement for 2003 to 2007.

13. TOTAL REVENUE REQUIREMENT

The elements of the Total Revenue equation for the Distribution System result in a revenue requirement for each year of the Second Access Arrangement Period as shown in the following table.

Cost Reflective Revenue Derivation ($m)	**2003**	**2004**	**2005**	**2006**	**2007**
Opening Regulatory Asset Base	683.3	706.0	730.7	757.9	786.5
50% Net New Facilities Investment	13.8	15.2	16.9	17.7	18.1
50% Regulatory Depreciation	(11.6)	(12.1)	(12.6)	(13.0)	(13.7)
CPI Escalation	17.4	17.5	18.2	19.0	19.8
50% Net New Facilities Investment	13.8	15.2	16.9	17.7	18.1
50% Regulatory Depreciation	(11.6)	(12.1)	(12.6)	(13.0)	(13.7)
Closing Regulatory Asset Base	704.9	728.5	755.2	783.5	811.9
Average Regulatory Asset Base	694.1	716.7	741.8	769.3	797.7
WACC	7.9%	7.9%	7.9%	7.9%	7.9%
Return on Assets	54.8	56.6	58.6	60.8	63.0
Regulatory Depreciation	23.3	24.3	25.3	26.1	27.4
Non-Capital Costs	43.8	44.5	45.6	47.3	49.0
Cost of Working Capital	1.5	1.6	1.8	1.9	2.1
Efficiency Carry-Over	0.0	0.0	0.0	0.0	0.0
Cost of Tax	7.2	8.0	8.5	9.1	9.9
Cost Reflective Revenue ($m)	**130.6**	**135.1**	**139.6**	**145.2**	**151.3**

NB: Rounded to nearest $0.1m

Table 29 Total Revenue Requirement

14. REFERENCE TARIFFS

14.1. Access Code Requirements

Sections 3.3 to 3.5 and section 8 of the Access Code set out various requirements in relation to Reference Tariffs and the Reference Tariff Policy. Section 3.3 of the Access Code states that an Access Arrangement must include a Reference Tariff for:

- at least one Service that is likely to be sought by a significant part of the market; and
- each Service that is likely to be sought by a significant part of the market and for which the Regulator considers a Reference Tariff should be included.

Section 3.4 of the Access Code states that, unless a Reference Tariff has been determined through a competitive tender process (as outlined in sections 3.21 to 3.26 of the Access Code), an Access Arrangement and any Reference Tariff included in an Access Arrangement must, in the Regulator's opinion, comply with the Reference Tariff Principles set out in section 8 of the Access Code. Section 3.5 of the Access Code states that an Access Arrangement must also include a policy describing the principles that are to be used to determine a Reference Tariff (a Reference Tariff Policy) and it must, in the Regulator's opinion, comply with the Reference Tariff Principles in section 8 of the Access Code.

Section 8 of the Access Code sets out the principles with which Reference Tariffs (other than those determined through a competitive tender process under section 3 of the Access Code) and the Reference Tariff Policy must comply in order to be approved. Overarching principles and factors to be observed in applying the Reference Tariff Principles in section 8 of the Access Code are set out in sections 8.1 and 8.2.

Section 8.1 states that a Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objectives:

- providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering the Service;
- replicating the outcome of a competitive market;
- ensuring the safe and reliable operation of the Pipeline;
- not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;
- efficiency in the level and structure of the Reference Tariff; and
- providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

Section 8.2 provides that the Regulator must, in approving a Reference Tariff and Reference Tariff Policy, be satisfied that:

- the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in section 8 of the Access Code;
- to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in section 8 of the Access Code;
- a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service is recovered from the Users of that Reference Service consistently with the principles contained in section 8 of the Access Code;
- Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in section 8 of the Access Code; and
- any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

Other specific provisions in section 8 of the Access Code will, where relevant, be referred to throughout the remainder of this Access Arrangement Information in discussing the compliance of the Access Arrangement with the Access Code.

14.2. Compliance

Consistent with the requirement of existing Fixed Principle 9.2(b)(1), Envestra has adopted a CPI-X approach to determining Tariffs, adopting a tariff basket approach to price control. Tariffs, and the Po and X factors that underly them have been derived using a four step process which is set out below.

Step 1 – Determination of Total Revenue

The Total Revenue requirement was determined as set out in section 13. As noted, the Total Revenue requirement excludes costs associated with the provision of excluded services.

Step 2 – Determination of Haulage Revenue

The revenue forecast to be generated from the provision of Ancillary Reference Services and Negotiated Services was deducted from the Total Revenue requirement to provide target revenue to be recovered from Haulage Reference Services:

$$HR = TR - ARS - NS$$

where

HR	=	Haulage Reference Services revenue required
TR	=	Total Revenue requirement (as explained in section 5)
ARS	=	Ancillary Reference Services revenue
NS	=	Negotiated Services revenue

Ancillary Reference Service revenue has been determined by multiplying the expected volume of these services, as set out in section 4.2.2, by their proposed tariffs. The tariffs have been determined following a detailed analysis of the current cost of providing these services and are assumed to increase by CPI annually. This results in the following forecast of revenue from Ancillary Reference Services:

Forecast Revenue from Ancillary Reference Services ($m)	**2003**	**2004**	**2005**	**2006**	**2007**
Meter and Gas Installation Test	0.03	0.03	0.03	0.03	0.03
Disconnection	0.01	0.01	0.01	0.01	0.02
Reconnection	0.35	0.36	0.36	0.37	0.38
Total	0.39	0.40	0.41	0.42	0.43

Table 30: Forecast Revenue from Ancillary Reference Services

Revenue from Negotiated Services has been assumed to be nil, for two main reasons.

- First, to the extent that Negotiated Services are sought that are fundamentally similar to the Haulage Reference Service, it can be expected that the volume of Haulage Services will decrease by corresponding amount, and thus there will be a zero net effect on revenue.

- Second, to the extent that Negotiated Services reflect non-haulage Services (for example, the connection of Tariff D Customers), costs associated with providing these Services have been excluded from the Total Revenue requirement in the first place and it is therefore consistent to exclude any associated revenue.

This process resulted in the following 'unsmoothed' haulage revenue requirement for the Access Arrangement Period:

	2003	**2004**	**2005**	**2006**	**2007**
Cost Reflective Unsmoothed Revenue Requirement	130.6	135.1	139.6	145.2	151.3
Ancillary Reference Service Revenue	0.4	0.4	0.4	0.4	0.4
Unsmoothed Haulage Revenue Requirement	**130.2**	**134.7**	**139.2**	**144.8**	**150.9**

Table 31 Unsmoothed Total Revenue Requirement

Step 3 – Smoothing of the Haulage Revenue Requirement

The haulage revenue requirement was "smoothed" across the forecast period by taking into account forecasts of demand and the assumptions set out in Step 4 in relation to 2003 tariffs. In particular, these assumptions are based around a Po adjustment of 1% for 2003, as discussed below. The revenue smoothing is designed to produce a constant X factor across the Access Arrangement Period, consistent with the requirement of Fixed Principle 9.2(b)(2).

The smoothing was undertaken consistent with the Regulator's preferred approach, which equates the net present value of the cost reflective revenue (CRR) stream and the forecast tariff revenue (FTR) stream as shown below.

Revenue Smoothing	
Cost Reflective Revenue (CRR)	Forecast Tariff Revenue
Minus	*Minus*
Net Capital Expenditure	Net Capital Expenditure
Minus	*Minus*
O&M Expenditure	O&M Expenditure
Minus	*Minus*
Cost of Tax#	Cost of Tax #
Equals	*Equals*
CRR Net Revenue	FTR Net Revenue

As forecast tariff revenue is likely to be different to the CRR in any year, the Cost of Tax is re-calculated based on the forecast tariff revenue. Forecast tariff revenue timing will be affected by demand growth profiles, P_0 and X-factor assumptions.

Table 32 Revenue Smoothing

The revenue smoothing leads to the following Smoothed Revenue Requirements and X factors:

	2003	**2004**	**2005**	**2006**	**2007**
Smoothed Haulage Revenue Requirement	118.5	129.1	140.1	152.6	166.2
X Factor	**1 (Po)**	**-4.4**	**-4.4**	**-4.4**	**-4.4**

Table 33 Smooth Revenue and X Factor

The X factor of –4.4% from 2004 to 2007 would result in significant real increases in distribution tariffs to consumers. Such an outcome may be seen to be inconsistent with the interests of Users and Prospective Users, which the Regulator is required to take into account in approving an Access Arrangement (Section 2.24).

To take into account the interests of Users and Prospective Users Envestra has reduced the slope of the price path to provide an X factor over the period 2004 to 2007 of –1.0%. This has been achieved by reducing the amount of depreciation returned to the business over the period.

The practice of adjusting depreciation to achieve appropriate pricing outcomes has been used in a number of other regulatory decisions, e.g. ACCC's decision on the Central West pipeline, the Regulator's decision on Envestra's Mildura distribution network. Further Envestra notes that the economic useful lives of assets used in both the First Access Arrangement and this revised Access Arrangement are short relative to the economic life assumptions approved by regulators in other access arrangements, e.g. SAIPAR's and QCA's decision on Envestra's South Australian and Queensland distribution networks. Thus the adjustment of depreciation to deliver the desired price path is a well accepted and practical means of providing an acceptable pricing outcome.

Further, section 8.33 of the Code explicitly enables depreciation to be deferred to subsequent periods. This revenue is then used to determine haulage Reference Tariffs.

The extent to which depreciation has been reduced is set out in the following table along with a revised target revenue requirement and proposed X factor. This revenue target is used to determine Haulage Reference Service Tariffs.

	2003	2004	2005	2006	2007
Unsmoothed Revenue Requirement	130.2	134.7	139.2	144.8	150.9
Return of Assets Adjustment	0.3	0.8	1.4	2.0	2.6
Depreciation Adjustment	(6.7)	(6.9)	(7.1)	(7.2)	(7.4)
Cost of Tax Change	(2.8)	(2.8)	(2.8)	(2.8)	(2.8)
Working Capital Change	0.0	(0.1)	(0.1)	(0.2)	(0.3)
Revised Unsmoothed Haulage Revenue Requirement	121.0	125.8	130.7	136.7	143.2
Revised Smoothed Haulage Revenue Requirement	118.9	125.3	131.7	138.7	146.2
Revised X Factor	1.0	(1.0)	(1.0)	(1.0)	(1.0)

Table 34 Modified Price Path and Haulage Revenue Requirement 2003-2007

Step 4 – Tariff Structure and Allocation of Haulage Revenue Between Haulage Reference Services

Envestra has elected to maintain the same structure of Haulage Reference Service Tariffs in 2003 as in the First Access Arrangement Period. Amongst other things, this ensures compliance with existing Fixed Principle 9.2(b)(10), which requires the Tariff V structure to remain in place in 2003.

Therefore, Tariff V will continue to be charged on the same zonal basis as the First Access Arrangement Period, and will comprise:

- a daily fixed charge; and
- four separate volumetric bands with declining block tariffs, and higher charges applying in the peak period compared to the off-peak period.

Similarly, Tariff D will continue to be based on the same zonal structure, with tariffs based on an anytime Maximum Hourly Quantity (MHQ) basis. Three declining block tariffs will continue to apply. Envestra believes there is good support from Users for continuation of the existing tariff structure.

Envestra has used existing tariffs approved by the Regulator to calculate tariffs to apply in 2003. Specifically, Envestra has elected to amend all tariff components by the same percentage amount in 2003. This percentage change is in part dictated by the Fixed Principle 9.2(b)(10) which requires each tariff component for consumers using less than 50 GJ per year to fall in real terms by 1% in 2003. Adopting a 1% fall in Tariff D components and other Tariff V consumers in 2003 means that the Po factor in 2003 is 1%.

In adopting this approach and complying with the Fixed Principles described above, and subject to slight movements in allocations caused by different rates of demand growth, revenue in 2003 is effectively allocated across Haulage Reference Services and Zones in the same manner as in the First Access Arrangement Period. This ensures compliance with Fixed Principle 9.2(b)(4) which requires the Regulator to provide outcomes for tariffs which are consistent with the public policy adjustments made when determining tariffs for the First Access Arrangement Period.

On the assumption that all tariffs will move by the X factor across the Access Arrangement Period, this results in the revenue set out in the following table below being generated across each Haulage Reference Service and Zone.

Tariff V Revenue – Central	**2003**
Fixed Charges	10.4
Peak	48.3
Off-peak	45.7
Total Central $m	104.4

Tariff V Revenue – North	**2003**
Fixed Charges	1.4
Peak	5.5
Off-peak	4.3
Total North $m	11.2

Tariff V Revenue – Murray V	**2003**
Fixed Charges	0.1
Peak	0.2
Off-peak	0.2
Total Murray Valley $m	0.5

Tariff D	**2003**
Central & North	2.7
Murray Valley	0.1
Total Tariff D $m	2.8

Total Haulage Revenue ($m)	**118.9**

NB: Numbers may not add due to rounding

Table 35 Revenue Requirement for each Haulage Reference Service 2003

15. REFERENCE TARIFF POLICY

15.1. Access Code Requirements

Section 3.7 of the Access Code states that an Access Arrangement must include a Reference Tariff Policy.

This Policy should address all of the principles that govern any movement in Reference Tariffs during an Access Arrangement Period. These principles may also influence Reference Tariffs for subsequent Access Arrangement Periods.

Section 3.7 of the Access Code states that the Reference Tariff Policy must, in the Regulator's opinion, comply with the Reference Tariff Principles set out in section 8 of the Access Code.

Section 8 of the Access Code identifies some possible elements of a Reference Tariff Policy. They include:

- Fixed Principles (sections 8.47 and 8.48 of the Access Code);
- Incentive Mechanisms; and
- a mechanism for treating redundant capital (sections 8.27 – 8.29 of the Access Code).

15.2. Compliance

Part B of the Access Arrangement contains the Reference Tariff Policy and includes details of how Reference Tariffs are amended from year to year and procedures for withdrawing or introducing new Tariffs.

15.3. Proposed Fixed Principles

Envestra has proposed a number of Fixed Principles which will apply in the Second and subsequent Access Arrangement Periods. These Fixed Principles are essential in ensuring a balanced, consistent and predictable approach to regulation and thereby reduce regulatory risk. These Fixed Principles are referenced and discussed below.

Incentive Based Regulation (7.1(e)(1))

Envestra generally supports the use of CPI-X incentive-based regulation as the best way of ensuring Distribution Services are delivered at efficient costs to Users. While Envestra acknowledges that the Regulator also supports this approach, it believes this position should be enshrined as a Fixed Principle.

This Fixed Principle is consistent with the existing Fixed Principle 9.2(b)(1).

Roll-Forward of the Capital Base (7.1(e)(2))

This Fixed Principle sets out the way in which the Capital Base should be rolled forward at the commencement of the Third Access Arrangement Period.

It is consistent with section 8.9 of the Access Code and existing Fixed Principle 9.2(b)(3), although two aspects of the proposed clause are worth highlighting.

First, section 7.1(e)(2)(D) provides that where assets are disposed of, the Capital Base will be reduced by the value of those assets in the Capital Base, and not the proceeds of sale.

Envestra does not support the Regulator's proposal to remove the proceeds of disposals from the regulatory asset base for the following reasons:

- removing the value in the Capital Base gives businesses the long-term incentive to grow markets and to achieve the best disposal price. Removing the sale proceeds achieves neither of these objectives, is inconsistent with incentive regulation and is simply a 'clawback' of increases/decreases in asset value;
- the sale value represents the value that the market puts on an asset, based on the best use that the market can put it to. It bears no resemblance to a regulatory asset value which in accordance with the Access Code has been established in a transparent, objective way consistent with regulatory principles, and represents the basis on which the asset has been regulated in the past;
- the adoption of the value in the Capital Base will avoid the possible "gaming" that might otherwise occur in asset sale negotiations and contracts such that any premiums over regulated asset values are likely to be attributed to non-regulated assets. Adopting the Capital Base value also avoids the need to ensure that asset are sold on an arms-length basis;
- if the sale value rather than the Capital Base value is used when an asset is sold, this means that there may be a revaluation for regulatory purposes of the remaining assets. Where large portions of the network have been sold the Capital Base could become negative.

Envestra believes that under the Access Code, changes in the market value of regulated assets are of no concern to the Regulator. Changes in market value should represent unregulated income or losses. To suggest otherwise is to suggest that the regulatory asset value should be equivalent to the market value and that the Initial Capital Base has been set inappropriately.

Second, section 7.1(e)(2)(E) provides that Redundant Capital will not be removed from the Capital Base. This Fixed Principle is consistent with existing Fixed Principle 9.2(b)(3)(E) which provides that the Capital Base will not be adjusted by the Regulator where shared assets become unused, but also extends this provision to apply to customer-specific assets.

Envestra notes support from the Regulator for its position in that it has stated that it will not attempt to identify stranded assets for the existing period and that in the longer term "*the Office remains of the view that the long-term interest of customers (as well as distributors) would be maximised by a policy that reduces the regulator-imposed uncertainty as to the recovery of the value of the distributors' regulatory asset bases.*"

Envestra supports the reasoning underlying this position, which includes:

- the direct impact on regulated charges of removing such assets is minimal compared to the long-term impact on prices that may arise from the increased risk associated with an active policy of identifying and removing redundant or partially redundant assets.

- administrative costs of identifying redundant assets are high compared to the materiality of any adjustment.

As Envestra has stated previously, it is not aware of any material assets that have become redundant over the First Access Arrangement Period and future periods are not expected to be any different. Experience across Australia over more than 100 years is also that capital redundancy in gas distribution systems is extremely rare.

Recovery of FRC Costs (7.1(e)(3) and (4))

The Government's introduction of FRC introduces a number of significant risks and uncertainties for distribution businesses, including in relation to the cost of implementing FRC. These Fixed Principles are designed to reflect the fact that:

- distribution businesses will incur significant costs to implement systems and processes to provide FRC by 1 October 2002 as directed by the Government;
- Costs associated with FRC should be recovered from Users and should not be borne by Envestra's shareholders;
- not all costs associated with FRC may be recovered by 31 December 2007; and
- there will be ongoing costs associated with FRC beyond 1 January 2008.

Post-Tax Approach to WACC (7.1(e)(5))

As noted elsewhere in this document, Envestra believes that the cost of capital should be determined on a real pre-tax basis, which was the approach adopted by the Regulator in 1998. However, in acknowledgment that the post-tax approach is now preferred by the Regulator, Envestra has submitted parameter values in a post-tax format.

Envestra believes that whatever approach is adopted by the Regulator for this Second Access Arrangement Period, it is important that this approach be adopted in future periods. Frequent changes to the approach to determining WACC increase uncertainty and risk. Distribution assets have very long lives so a stable method of determining returns must be adopted. If the Regulator is given the discretion to change approaches at any time, Envestra is concerned that it might be possible for future Regulators to change approaches with the objective reducing Envestra's revenue.

The regulatory risk associated with such an event is extreme, and Envestra believes it is in the interests of both Service Providers and the Regulator to lock in a WACC approach over an extended period.

Retailer of Last Resort (7.1(e)(6))

The Government may impose requirements on Envestra to meet certain obligations under a retailer of last resort (RoLR) scheme. Forecasts of costs included in this Access Arrangement do not include any allowance for these obligations if Envestra is required to participate in a RoLR scheme. As with FRC expenses, these costs should not be borne by Envestra's shareholders.

Envestra's preference is that these additional expenses be treated as a pass-through in the same manner as a Change in Taxes event whereby Envestra would make a submission detailing its additional costs to the Regulator, including the basis on which the costs would be passed through, and the Regulator would have the opportunity to review these costs and approve the pass-through amounts.

Regulatory Reviews (7.1(e)(7))

Given the Productivity Commission's recent review of the National Access Regime, and the Commonwealth Government's intention to review the Access Code, it is possible that some aspects of the Access Arrangement and Fixed Principles may become redundant or inconsistent with a revised Access Code. In such circumstances it is appropriate for Envestra to be able to remove one or more of the Fixed Principles to the extent that such deletions are not or do not become inconsistent with the amended Access Code.

15.4. Efficiency Sharing Mechanism

Envestra has proposed a mechanism to ensure it has appropriate incentives to increase demand for services and decrease operating and capital costs.

The efficiency sharing mechanism is designed to achieve an appropriate balance between providing an incentive for Envestra to reduce costs and increase sales of services, and ensuring Users (and ultimately Customers) benefit from those cost reductions and increased volume of sales. It is based around the principles that:

- there should be no ‘claw-back’ of gains that have already been made (or losses that have been incurred) during the current regulatory period; and
- a CPI-X price control mechanism alone may not provide the correct incentives to increase sales and reduce costs, particularly at end of the regulatory period, and a formal ‘carryover’ of gains into future Access Arrangements Periods is therefore necessary.

The approach adopted by Envestra is consistent with the carryover mechanism proposed by the Regulator in its *Position Paper*.

However, Envestra’s model incorporates two longer-term improvements over the approach proposed by the Regulator. These are:

- the efficiency carryover mechanism will apply for ten years, not five. This removes the imbalance between the interests of the Service Provider and Users in the Regulator’s proposal; and
- rather than adjusting forecast expenditure for changes in scope and output, actual expenditure will be amended.

These adjustments are discussed below, as is the shorter term requirement that there be no negative carryovers arising from the First Access Arrangement Period.

Length of Efficiency Carryover Period

Envestra has proposed a 10-year carryover rather than 5 years as advocated by the Regulator. This does not alter the general operational properties of the mechanism proposed by the Regulator, with the only exception that benefits are retained across two Access Arrangement Periods.

The result of the 10 year approach is that it improves the ratio of benefit sharing between Envestra and Users from around 30% under the Regulator’s proposals, to approximately 50% (depending upon the exact timing and structure of gains and discount rate adopted).

There are a number of reasons why this increase in sharing is necessary. Firstly, the sharing ratio proposed by the Regulator is not consistent with the requirement for a ‘fair sharing’ of the benefits required in the Fixed Principles in the Tariff Order. A more reasonable interpretation of ‘fair sharing’ is that benefits will be divided approximately equally between the business and Users.

Envestra disputes the Regulator’s view that a ‘fair’ sharing of benefits is inconsistent with an ‘equal’ sharing and that a 50:50 sharing is not ‘fair’ or ‘efficient’. The Regulator has not satisfactorily demonstrated that 30:70 is fairer or more efficient than 50:50.

Secondly, under the Regulator’s 30:70 approach risk and reward are not aligned. Retention of only 30% of the efficiency gains is not sufficient incentive for the Service Provider to take the risks necessary to maximize efficiency gains, particularly if there is a risk of negative carryovers occurring.

For the Regulator to implement its proposed approach would be inconsistent with the basis upon which investment and expenditure decisions in the industry have been made over the First Access Arrangement Period.

Envestra notes that in the Electricity Price Determination the Regulator expressed a view that it is desirable to quarantine the efficiency carryover to one subsequent regulatory period, rather than two. Envestra does not believe that this is necessary and that given the transparency of the model proposed there is no reason why the mechanism cannot extend over two regulatory periods. The implementation of efficient incentive mechanisms should not be artificially constrained by the length of regulatory periods. Fixed Principle 9.2 (b)(6) expressly contemplates efficiency gains being shared over more than one access arrangement period.

Finally, a 10 year carryover with 50:50 sharing is consistent with the Productivity Commmission’s recommendations that greater incentives need to be provided for investment and the cost of failing to invest in infrastructure are likely to be larger than the costs of monopoly pricing of infrastructure services.

Adjustments to Actual Expenditure, not Forecast Expenditure

Envestra supports the Regulator’s view that the efficiency sharing mechanism should take into account changes in scope and output from those envisaged in establishing the initial cost forecasts. Only by making these adjustments are Service Providers given the incentive to promote sales of services and develop the market, as required by sections 8.46 and 8.2(f) of the Access Code.

However, Envestra believes it is more appropriate to make changes to actual expenditure rather than adjust forecasts after they have been approved by the regulator. A post-approval adjustment of forecasts has potential to create regulatory risk that is inconsistent with the philosophy of the Access Code ie to set regulatory parameters in advance for a fixed period. Moreover, businesses implementing changes of scope always evaluate financial impacts relative to actual costs – not regulatory forecasts. Indeed, depending on the nature of the adjustment being made, there may be insufficient information available in the forecast information to calculate the adjustment accurately especially where the business has been able to make significant productivity improvements. The lack of information is less likely to be a problem when the basis for the adjustment for scope is actual costs.

No Negative Carryovers for the initial Access Arrangement Period

Envestra believes there should be no negative carryover applying to any individual year as a result of carryovers from the First Access Arrangement Period. This was the approach adopted by the Regulator in its Electricity Price Determination, on the basis that:

- the principle of symmetric treatment of gains and losses had not been widely discussed earlier in the current regulatory period; and
- including a negative carry-over as part of the carry-over mechanism for the 1995-2000 cannot influence businesses 'past behaviour.

The same reasoning applies in the gas industry. The Regulator's initial views on efficiency sharing in the gas industry were not communicated until late in 2001. Views on efficiency sharing in the electricity industry were not determined until late 2000 and even then were subsequently amended following the decision of the Appeal Panel on matters of scope change. Envestra's decisions on investment and expenditure for 1998, 1999, 2000 and (for some items) 2001 had already been made by this time.

In addition, as discussed in section 3 in this document it is clear that cost benchmarks for the period 1998 to 2001 were set at levels that were unrealistically low and therefore should not be used for the purposes of applying penalties.

Finally, to apply a negative carryover for the First Access Arrangement Period would be inconsistent with the Fixed Principles which provides for a sharing of efficiencies where Envestra "*has achieved efficiencies greater than the value implied by the value of XD*" but which does not canvass or imply that Envestra should be penalised where cost forecasts are not achieved. Such an approach would also conflict with clause 8.44 of the Access Code which provides that the Incentive Mechanism relate to "*returns ….. from the sale of Reference services during an Access Arrangement period that exceeds the level of returns expected at the beginning of the Access Arrangement Period".* This clause does not contemplate penalties or negative carryovers.

15.5. Other elements of the Reference Tariff Policy

Part B of the Access Arrangement contains the Reference Tariff Policy and includes details of how Reference Tariffs are amended from year to year and procedures for withdrawing or introducing new Tariffs. The Reference Tariff Policy generally reflects provisions from the First Access Arrangement Period, the Tariff Order, and the Regulator's decisions on price control parameters in the electricity industry.

The structure of tariffs for the Haulage Reference services is the same as that applying in the First Access Arrangement Period, ie fixed and variable charges, with different charges for peak and off-peak haulage and decreasing tariff bands. The relative prices of the bands and relative zonal charges are unchanged, thus reflecting the basis on which costs were originally allocated.

Consistent with the Regulator's preference (and the Fixed Principles) a tariff basket approach to price control has been proposed.

The above provide for continuity of existing practice, with which Users are familiar, and therefore a smooth transition to the Second Access Arrangement Period.

The following areas are those where the mechanisms to be implemented in the Second Access Arrangement Period differ materially in relation to the First Access Arrangement Period or existing electricity arrangements.

Rebalancing Controls

The rebalancing controls applying in the First Access Arrangement Period which applied at a tariff component level, have been unduly restrictive both in terms of:

- enabling Envestra to adjust relative tariffs; and
- enabling Envestra to adjust all tariffs in order to meet maximum allowable average tariff revenue.

Envestra accepts that rebalancing constraints are legitimate instruments for protecting certain customer classes from tariff shocks. However, the rebalancing controls in the Second Access Arrangement Period need to be more liberal than in the first, both in terms of their numerical value, and the level at which they apply.

Envestra has therefore proposed average rebalancing controls of CPI+5% for Tariff V customers, and CPI +15% for Tariff D customers to apply from 2004 to 2007. These rebalancing constraints are reasonable noting that:

- movements in Tariff V tariffs are ultimately constrained by the X factor rather than this rebalancing constraint; and
- Tariff D distribution charges represent such a small proportion of a customer's overall gas bill that even a 15% increase over 4 consecutive years will not significantly affect retail tariffs for these customers.

Change in Tax Pass Through

The tax pass through provision proposed in the Access Arrangement provides a fair and reasonable mechanism which ensures Envestra is not penalised:

- for additional service level or regulatory requirements (eg increases in service standards) imposed subsequent to the approval of the Access Arrangement for the Second Access Arrangement Period. The mechanism is symmetric in that where regulatory burdens decrease, Users will benefit from corresponding decreases in Reference Tariffs;

- where changes in other non-controllable factors occur (eg licence fees). Again, this principle is symmetric.

In the absence of these provisions, the potential exists for gas distributors' obligations and costs to increase above those levels assumed in the calculation of Reference Tariffs. This might occur either through changes in Victorian regulatory instruments (eg the Distribution System Code) or other external mechanisms. While Envestra accepts that the majority of cost-risk is best borne and managed by the distributor, some 'non-controllable' risks are best borne by Users and not distributors.

16. TERMS AND CONDITIONS

16.1. Access Code Requirements

Section 3.6 of the Access Code states that an Access Arrangement must include the terms and conditions on which the Service Provider will supply each Reference Service. It also provides that the terms and conditions included must, in the Regulator's opinion, be reasonable.

16.2. Compliance

The terms and conditions (T&C) applicable to the provision of Reference Services are dealt with in Part C of the Access Arrangement.

The T&C applying to provision of the Haulage Reference Services and the Ancillary Reference Services are consistent with good industry practice and are 'reasonable' in that they:

- are sufficiently well defined, so that the likelihood of a dispute over the terms and conditions of access is minimised; and
- are designed to protect the legitimate business interests of Envestra, as well as Users and Prospective Users.

Envestra is aware of the significant consultation and negotiation process involved in the implementation of 'use of system' agreements in the Victorian Electricity industry (Electricity UoS). In order to facilitate ease of commercial management within the converging energy industry in preparing the T&C, and to reflect the known preferences of Retailers (the majority of which operate in both the electricity and gas industries), Envestra has used the Electricity UoS as a template. Departures from the Electricity UoS have occurred to generally:

- address matters specific to the gas industry;
- remove matters relevant to the electricity industry that are not relevant to the gas industry; and
- reflect current gas industry contractual arrangements and practices in Victoria.

The T&C cover the following key areas:

- **Reasonable Terms and Conditions**
  Envestra submits that the T&C are reasonable for the purposes of clause 3.6 of the Access Code.

- **Compliance with Regulatory Instruments (clause 2)**
  As part of achieving clarity in the terms and conditions of access, Envestra has sought to minimise reliance upon rights and obligations derived from regulatory instruments. However there are some instances where the subject matter of a commercial term is already dealt with in a regulatory instrument. In these circumstances the T&C use terms in the same manner as they are used in, and

otherwise simply refer to, those instruments and thus there is no inconsistency between the rights and obligations that flow. Clause 2 seeks to foster an harmonious operation of the T&C and regulatory instruments.

- **Customer Relationship (clause 3)**
  The T&C have been prepared on the basis that the User would be a licensed gas retailer and that services will be provided in a "straight line" manner, namely:

  - Envestra will provide Distribution Services to the User under the T&C; and
  - the User will provide Distribution Services *and* gas supply to the customer under a retail contract.

  Clause 3 recognises that a User may contract with a customer only for supply of gas and, in that situation, Envestra would contract with the customer directly for network services (a "triangle" relationship). The contractual arrangements for a triangle relationship would be negotiated directly with the customer and be documented outside the terms of the T&C.

- **Distribution Services (clause 4)**
  The Distribution Services provided under the T&C are defined as:
  - Reference Services
  - services provided pursuant to the Gas Market Retail Rules (the charges for which are subject to separate regulatory arrangements but which are otherwise not subject to commercial arrangements);
  - non-Reference Services (as agreed or determined pursuant to the Access Code); and
  - connection.

These matters, other than Reference Services, are included as relevant matters in accordance with section 2.29 of the Access Code.

In the 'default' T&C, the description of the non-Reference Services (in a schedule to the T&C) will include the non-Reference Services dealt with in the default T&C and will be completed for other known non-Reference Services by Envestra and the User at the time the actual contract is signed. The T&C also make provision for that schedule to be amended from time to time by agreement between the parties or as a result of an arbitration and so the schedule can be updated each time a new non-Reference Service is agreed or determined.

This clause describes the manner in which the Distribution Services must be provided by Envestra to the User.

- **Connection (clause 5)**
  Specific processes *as between the Service Provider and the User* are set out in

this clause. These processes supplement the Regulatory Instruments and operate in conjunction with the Regulatory Instruments.

- **Disconnection and Interruption of Customers (clause 6)**
  Specific processes *as between the Service Provider and the User* relating to disconnection and interruption of customers, as well as reconnection and restoration of supply are covered in this clause. These processes supplement the Regulatory Instruments and operate in conjunction with the Regulatory Instruments.

- **Payment and Billing for Distribution Services (clause 7)**
  Envestra will invoice for network services twice monthly, reflecting current gas industry practice. Reference Tariffs have been predicated on continuation of current billing practice and associated cashflows.

The provision of metering data is not covered in the T&C as this is included in the Gas Retail Market Rules.

Envestra may require the User to provide an unconditional bank guarantee to secure payment of the charges. The amount of the bank guarantee must not exceed Envestra's reasonable estimate of 3 months average charges. This reflects existing agreements and current gas industry practice.

- **Information Exchange (clause 8)**
  Clause 8.2(b), has been included to address specific privacy issues arising under the new privacy regime.

The method, format and content of certain communications contemplated in the Gas Interface Protocol, are addressed.

- **Communications regarding customers and system data (clause 9)**
  This clause deals with specific operational matters relating to communications *between the Service Provider and the User* regarding customers and system data.

Further classes have been introduced, reflecting existing agreements and gas industry practice, namely:

- information regarding new supply points to be connected. This information is necessary to enable physical connection and for determining the appropriate tariff; and
- the processes for assignment of and change in Reference Tariff or Distribution Services.

- **Force Majeure (clause 10)**
  The definition of Force Majeure Event is as per the Distribution System Access

Code.

- **Enforcement of Envestra's rights against customers (clause 11)**
  This clause deals with various matters *as between the Service Provider and the User* in relation to enforcement action taken by Envestra against the customer. Essentially, Envestra will consult with the User before taking such action, unless the circumstances are such that consultation would not be appropriate.

- **Term and Termination (clause 12)**
  Envestra can terminate the T&C where the User defaults or becomes insolvent, subject to notice and cure rights. Reflecting existing agreements, there is a separate regime for termination where the User jeopardises the safety or integrity of the Distribution System. This requirement stems from the fundamental obligation of a gas network owner to ensure that public safety is not compromised, and in turn manage liability.

  The clause recognises that there must be continuity of supply to the customer, despite termination of the broader commercial arrangement between Envestra and the User.

- **Liabilities and indemnity (clause 13)**
  Each party will have uncapped liability and exposure to indirect and consequential loss. This reflects the existing regulatory regime which does not permit Envestra or the User to include limitations in their arrangements with customers. Clauses 13.5 and 13.6 reflect existing agreement and current gas industry practice and are important issues from an operational perspective.

17. CAPACITY MANAGEMENT POLICY

17.1. Access Code Requirements

Section 3.7 of the Access Code requires that the Access Arrangement must include a statement of whether system capacity is managed on a Contract Carriage or a Market Carriage basis.

17.2. Compliance

Section 5 of the Access Arrangement provides that the Distribution System is to be a Market Carriage Pipeline.

18. QUEUING POLICY

18.1. Access Code Requirements

Section 3.12 of the Access Code states than an Access Arrangement must include a policy for determining the priority that a Prospective User has, as against any other Prospective User, to obtain access to Spare Capacity and Developable Capacity (and to seek dispute resolution under section 6 of the Access Code), where the provision of the Service sought by that Prospective User may impede the ability of the Service Provider to provide a Service that is sought by, or which may be sought by, another Prospective User. The Access Code refers to this policy as a Queuing Policy.

Section 3.13 of the Access Code states that the Queuing Policy must set out sufficient detail to enable Users and Prospective Users to understand in advance how the Queuing Policy will operate. Section 3.13 also states that the Queuing Policy must accommodate, to the extent reasonably possible, the legitimate business interests of the Service Provider, Users and Prospective Users and generate, to the extent reasonably possible, economically efficient outcomes.

18.2. Compliance

Section 7 of the Access Arrangement sets out the Queuing Policy for the Distribution System.

Queuing is more relevant to transmission pipelines than distribution networks. In relation to transmission pipelines, all Users essentially use the same pipeline and the development of incremental capacity typically requires significant investment that cannot be supported by a single User. It is therefore appropriate to consider Users' requests for extra capacity in aggregate and develop a queuing policy to determine the priority for allocating the additional capacity.

In distribution networks, Spare Capacity is location-dependent and may vary daily or seasonally, depending on the demand profile of different Customers and the resultant flow paths. Additional capacity can usually be provided in small increments to specific locations. As a result, queuing within a distribution network is much less of an issue than with transmission pipelines, and consequently a Access Code amendment is currently under consideration to address this anomaly.

19. EXTENSIONS AND EXPANSIONS POLICY

19.1. Access Code Requirements

Section 3.16 of the Access Code states that an Access Arrangement must include a policy (Extensions and Expansions Policy) that sets out:

- the method to be applied to determine whether any extension to, or expansion of the Capacity of, the Covered Pipeline:
- should be treated as part of the Covered Pipeline for all purposes under the Access Code; or
- should not be treated as part of the Covered Pipeline for any purpose under the Access Code;
- how any extension or expansion which is to be treated as part of the Covered Pipeline will affect Reference Tariffs; and
- if the Service Provider agrees to fund New Facilities if certain conditions are met, a description of those New Facilities and the conditions on which the Service Provider will fund the New Facilities.

19.2. Compliance

Section 8 of the Access Arrangement sets out the Extensions and Expansions Policy for the Distribution System. It identifies the circumstances under which any extensions to or expansions of the Distribution System will be treated as part of the Distribution System (ie as the one Covered Pipeline under the Access Code) and the Tariffing arrangements to apply to any extension or expansion.

In the Access Arrangement, references to extensions or expansions are references to extensions or expansions to the Distribution System as it will exist on 31 December 2002.

Unreticulated Townships
Envestra has included in its forecasts of New Facilities Investment the costs of extending the network to one unreticulated town. There may be opportunities during the Access Arrangement Period to extend the network to other unreticulated townships, the costs of which have not been included in forecasts used to derive Reference Tariffs. Envestra believes that, in the event such an opportunity arose, such projects are of a nature that require individual assessment with respect to regulatory arrangements. Section 5.6.3 of the Access Arrangements sets out a policy to resolve regulatory issues associated with such extensions.

Capital Contributions
In order for capital expenditure to be rolled-in to the Capital Base, the Access Code requires growth-related capital expenditure to generate additional revenue that covers, at least, the additional costs incurred. This is referred to as the economic feasibility test. If this condition is not met, then the Service Provider has the option of recovering the deficit by seeking a Capital Contribution or levying an additional charge (a Surcharge) on the additional customers served.

The respective economic feasibility test for each Haulage Reference Service is as follows:

(1) **Tariff V**

Costs will be determined as follows:

- Capital cost – the standard installation cost of a service will be based on the average cost of a 'line of main' connection. Where a mains extension is involved, the capital cost will include the estimated cost of the mains extension. Where particularly adverse installation conditions occur, estimates of actual costs will be used.
- Operating costs – the efficient costs of providing the service for a DSP of that category will be used.

Revenue will determined as follows:

- for a Residential DSP – the average consumption for an assumed appliance mix will be used, unless there is specific information available (e.g. where the number of gas appliances to be connected is known);
- for non-Residential Tariff V DSPs – an estimate of the quantity and profile of actual gas consumption which takes into account the actual application will be used;
- the relevant Reference Tariff will then be applied.

Where the IRR of the connection exceeds the hurdle rate, it will be deemed to be economic.

(2) **Tariff D**

The economic feasibility test is the same as for non-Residential Tariff V DSPs.

20. REVIEW OF ACCESS ARRANGEMENT

20.1. Access Code Requirements

Section 3.17 of the Access Code states that an Access Arrangement must include a date upon which the Service Provider must submit revisions to the Access Arrangement and a date upon which the next revisions to the Access Arrangement are intended to commence.

If an Access Arrangement Period is more than five years, section 3.18 of the Access Code requires the Regulator to consider whether mechanisms should be included to address the risk of forecasts proving incorrect.

20.2. Compliance

Section 9.1 of the Access Arrangement stipulates the date for submission of revisions and the date on which their approval takes effect under the Access Code. The Second Access Arrangement period will be 5 years, consistent with standard regulatory practise.

21. SYSTEM CAPACITY

Envestra's Distribution System serves the northern, outer eastern and southern areas of Melbourne, Mornington Peninsula and rural communities in northern and north-eastern Victoria from Echuca to Wodonga.

The Distribution System is divided into three tariff Zones:

- Central
- Northern
- Murray Valley

The following table summarises the length of mains in each Zone at March 2001.

Zone	*Kilometres*	*%*
Central	6,490	82
Northern	1,214	15
Murray Valley	238	3
Total	7,943	100

Table 36 Distribution System Length by Zone

The Distribution System receives gas from 51 Custody Transfer Metering Stations (CTM). Pressure within the Distribution System is controlled by approximately 220 pressure reduction installations (PRIs).

The Distribution System is comprised of a number of materials of construction and various mains diameters ranging from 20mm to 900mm. The development of polyethylene pipe technology has had a significant effect on pipe materials used in the system. While cast iron and PVC pipe were used last century, polyethylene and steel are now exclusively used for new mains. Gas mains are designated either Transmission, High, Medium or Low pressure. Transmission pipelines are those operating over 1050 kPa. With High, Medium and Low pressure tiers operating at pressures below 515 kPa. The following table summarises the length of mains by pressure tier.

Pipe Diameter (mm)	Low	Medium	High	Trans.	Total
Up to 40	4.5	1.3	2,231.3	0	2,237.1
50	67.6	16.3	2,537.3	0.040	2,621.3
80	19.9	0.4	120.5	4.6	145.5
100	976.6	6.8	532.0	32.5	1,548.0
125	2.9	0.022	101.8	0	104.8
160	385.3	16.2	330.1	14.8	746.6
200	4.9	3.4	162.5	70.9	241.8
250	24.9	11.8	27.6	15.7	80.1
300	49.3	10.6	39.5	39.8	139.3
450	23.6	19.6	2.5	19.8	65.6
600	2.2	9.7	0	0	11.9
900	0.3	0.09	0	0	0.410
Total	1,562.4	96.4	6,085.6	198.5	7,943.1

NB Numbers may not add due to rounding

Table 37 Distribution System Length (km) by Pressure Tier

22. FORECASTS OF DEMAND

22.1. Purpose and Regulatory Requirement

This section summarises the forecast of gas volumes expected to be delivered via the Distribution System over the period 2003 to 2007.

Forecasts have been prepared in accordance with the Access Code which requires that they represent “best estimates arrived at on a reasonable basis”. Further, they are consistent with the Regulator’s requirement that the methodology used to generate the demand forecast:

- has been applied in an unbiased manner (ie due weight was given to all the relevant factors);
- is appropriate to the situation and the nature of the gas market;
- recognises and reflects key drivers of demand;
- is based on reasonable assumptions using the best available information;
- has been assessed against existing forecasts and methodologies;
- has used the most recent data available and historic data that can identify trends in growth; and
- has taken account of current demand and economic conditions and reasonable prospects for future market development.

The forecast has been subject to independent verification by actuaries and gas forecasting experts Trowbridge Consulting. A copy of the verification report is at Attachment D to this Access Arrangement Information.

22.2. Review of Demand from 1999 to 2001

Demand forecasts for the Distribution System from 1999 to 2001 were clearly optimistic.

The reduction in overall Tariff V volumes relative to forecast primarily reflects lower demand in the Central Zone. The North Zone has experienced slightly greater demand than forecast, and volumes in the Murray Valley Zone, whilst higher than anticipated in early years, fell 30% below forecast in 2001 as the number of new connections tailed off.

The following tables compare actual demand with forecast demand[8]. Reasons for the

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[8] as set out in the Access Arrangement Information for Stratus Networks, Final Version, November 1998

failure of demand to achieve forecasts are discussed below.

	Central Zone			North Zone			Murray Valley Zone		
Year	Forecast TJ	Actual TJ	% Diff	Forecast TJ	Actual TJ	% Diff	Forecast TJ	Actual TJ	% Diff
1999	25,215	24,127	-4.3%	2,863	2,880	0.6%	73	189	158.5%
2000	26,024	25,675	-1.3%	2,972	3,127	5.2%	120	272	127.0%
2001	26,819	25,690	-4.2%	3,071	3,114	1.4%	161	113	-29.5%

	Total		
Year	Forecast TJ	Actual TJ	% Diff
1999	28,151	27,196	-3.4%
2000	29,116	29,074	-0.1%
2001	30,051	28,917	-3.8%

Table 38 Tariff V Volumes (TJ) Comparison of Forecast and Actual Demand

Although it is difficult to determine Tariff D forecasts from the Access Arrangement Information, actual MHQ appears to be around 20% lower than forecast.

Reasons for the shortfall in demand

Demand has failed to achieve forecasts for a number of reasons, including:

Weather - Forecasts were prepared on the assumption of the 20 year average Melbourne Effective Degree Days (EDDs) from 1976 to 1996. This was 1537 Effective Degree Days (EDDs). However, actual weather was been substantially warmer in every year from 1998 to 2001, with the average number of EDDs reported by VENCorp being 1,348 over this period.

Number of New Connections - Growth in Tariff V connections failed to reach forecasts, despite excellent economic conditions and an unprecedented housing boom over this period, particularly in metropolitan fringe areas. Victorian new dwelling completions in 2000 and 2001 were close to double 1996 levels. The construction boom was caused by a number of factors, including the onset of the GST and the new homeowners grant. The table below shows the growth in new dwelling completions in Victoria:

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Year	Number	% Increase
1995	29,143	
1996	22,804	-21.8%
1997	27,533	20.7%
1998	33,323	21.0%
1999	36,610	9.9%
2000	42,464	16.0%
2001 (est)	41,406	-2.5%

Table 39 Number of Completed Dwellings

The 1998 forecasts assumed an overall increase of 39,200 customers across Envestra's Zones between 1998 and 2001. However, only 32,200 customers were added across this period, despite the large and unforeseen increase in new dwelling completion.

	Central Zone			North Zone			Murray Valley Zone		
Year	Forecast	Actual	% Diff	Forecast	Actual	% Diff	Forecast	Actual	% Diff
1999	365,000	361,112	-1.07%	51,000	49,291	-3.35%	1,500	984	-34.40%
2000	376,000	370,476	-1.47%	52,000	50,488	-2.91%	2,600	1,764	-32.15%
2001	386,000	378,059	-2.06%	54,000	51,463	-4.70%	3,600	2,299	-36.14%

	Total		
Year	Forecast	Actual	% Diff
1999	417,500	411,387	-1.46%
2000	430,600	422,728	-1.83%
2001	443,600	431,821	-2.66%

Table 40 Customer Numbers '000

Growth was generally consistent across the Central and North Zones. In line with the recent construction of the Murray Valley Network, growth in the new Murray Valley Zone was much more rapid, but less than expectations. Total connections in the Murray Valley Zone as at June 2001 were only half of the original forecast. This reflects both a slightly slower capital works program than anticipated, together will lower penetration rates than forecast.

Economic Conditions

Envestra does not have access to the detailed data economic data used in generating the 1998 forecasts. However, it is clear that economic conditions during the period 1998 to 2001 were generally more favourable than anticipated at the time. Projections for

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Victorian GSP and Dwelling investment for 1997/98 to 2000/01 set out in demand forecast review reports commissioned by the Regulator were exceeded.

However, higher levels of economic activity failed to translate into increased gas demand. The improved conditions increased building activity above forecast levels, however new meter connections were still less than originally forecast, reflecting lower gas penetration. In the commercial and industrial sector, the greater economic activity still failed to push demand above forecast levels, suggesting that the link between economic activity and non-domestic demand is relatively weak.

Demand per Customer

The 1998 forecasts were based on an assumed annual growth in demand of 0.4% to 0.6% per domestic customer, and 0.75% for commercial customers. Actual growth per connection (on a weather normalized basis) was significantly less than this and in 2001 compared to 2000 average domestic usage fell 0.2%. Average use for industrial and commercial customers fell by even more significant amounts.

Explanations for negative growth include the following:

- the 1998 Longford outage resulted in a shift away from gas demand towards alternative fuels, particularly in the domestic market;
- significant real reductions in electricity prices for major users prevented gas from increasing its market share amongst these customers;
- appliance survey information available to Envestra suggests that since 1990 gas has lost market share as the preferred fuel for space heating and as fuel for the main household cooking appliance;
- reducing number of persons per household;
- the efficiency of gas appliances has increased; and
- marketing of gas as a fuel has reduced since the early to mid 1990s.

Tariff D

Little information is available on the methodology adopted for forecasting Tariff D volumes and Envestra notes that the review of demand for the ORG was unable to reconcile Tariff D forecasts with those used in the revenue projections and reflected in the Access Arrangement Information.

However, it is clear that there were no ‘surprise’ new loads in Envestra’s distribution area during the period. To the extent that large gas users did eventuate, these were not connected to the distribution system.

The 1998 forecast assumed almost zero growth in total tariff D demand over the period. In reality MHQ fell despite a large number of Tariff V customers moving

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across to Tariff D in 2001. Few 'new' Tariff D customers connected to the system. The reduction in MHQ appears to be mainly due to a significant decline in usage by existing large customers.

22.3. Forecasting Methodology

Tariff V Customers

The demand forecast for tariff V customers (which comprise all but the largest 201 customers and accounts for 97% of revenue) represents a combination of a 'top-down' and 'bottom-up' approach to forecasting. That is, it reflects:

- a detailed review and regression analysis of demand by users in the First Access Arrangement Period. This analysis includes the development and use of regression equations for individual DSPs to project likely demand for 2003 to 2007;
- an assessment of new connections and meter removals anticipated over the Second Access Arrangement Period;
- an overview of the key drivers of gas demand for each market sector; and
- a high-level check of the aggregate demand forecasts against other publicly available information on demand in the gas sector.

In brief, the regression analysis is based around the formula:

$$Cn = Cb + k * EDD$$

where Cn = Consumption per Day(GJ / Day)

Cb = Intercept (Base Consumption GJ / Day)

k = Slope (GJ / EDD)

EDD = Effective Degree Days

The intercept represents the base load. i.e. weather-independent consumption (eg cooking, water heating). The slope represents the heating load. i.e. weather-dependent consumption (eg heating).

The regression has been designed to systematically recognise and exclude 'bad' points using a criterion that measures the deviation of each point from the mean. It then recomputes the regression, continuing until no points deviate above the allowable maximum.

Demand from existing customers represents the vast majority of forecast demand. The regression analysis is designed to estimate this demand as precisely as possible. While the forecasts of new growth are important, overall demand forecasts are extremely insensitive to assumptions made regarding new connections.

Tariff D Customers

The demand forecast for Tariff D customers has been built up on a customer-by-customer basis, and reflects:

- historic levels of demand;
- Envestra's knowledge of plans for increases or decreases in demand by existing consumers;
- likely movements in customers between Tariff V and Tariff D;
- a survey of major customers; and
- Envestra's knowledge regarding potential new Tariff D loads in Envestra's distribution area over the period.

22.4. Forecasts

Tariff V

Consistent with traditional approaches, demand by Tariff V customers has been analysed in three categories – domestic, commercial and industrial.

Given the relatively mature gas market in Victoria, the prime driver of demand by domestic customers is weather, with new customers (predominately new homes) providing the major increments in aggregate demand. The state of the building industry, coupled with active marketing in the new homes market, are therefore important in determining demand in the domestic sector.

Envestra engaged independent forecasters NIEIR to provide projections of activity in the building industry, including new dwelling completions. NIEIR's forecasts suggest that the current high level of dwelling completions will continue through 2002, before returning to levels more consistent with historic averages in 2003.

In relation to weather Envestra has adopted the VENCorp standard for Effective Degree Days (EDDs) of 1445 for year 2002 weather. In recognition of the continuing downward trend in EDDs, for subsequent years Envestra has assumed a reduction of 5.5 EDDs per annum. This is consistent with analysis undertaken by VENCorp and a paper which has been prepared by the CSIRO which suggests continuation of warming will occur both due to increased urbanization and the greenhouse effect.

Growth in demand from domestic customers is due entirely to the addition of new customers to the network. The number of new connections reflects anticipated activity in the housing industry, which is anticipated to level off from existing high levels. Also demand per connection from existing domestic customers is anticipated to continue to fall marginally, due to:

- the reduction in EDDs reducing heating-dependent load; and

ATTACHMENT A

WEIGHTED AVERAGE COST OF CAPITAL

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Tables and Figures

A1. PREAMBLE

This attachment sets out in detail the basis of Envestra's estimate of the Weighted Average Cost of Capital (WACC) for the Second Access Arrangement Period.

Envestra has applied the Capital Asset Pricing Model (CAPM) to derive its estimate of the Cost of Capital. The CAPM is widely used for this purpose in commercial practice. Australian regulators, including the Regulator, also use it to estimate the Cost of Capital for regulated infrastructure owners.

Envestra has adopted a number of high level principles to guide its application of the CAPM. These principles, which are consistent with those espoused by the Regulator, also reflect an explicit recognition that:

- The market price for investment capital cannot be observed, and therefore can only be inferred from the available evidence;
- The CAPM is a theoretical model that does not fully explain security returns; and
- There are significant information constraints, estimation challenges and uncertainties that exist in applying such a model in practice, particularly in a regulatory context.

Having regard to these considerations, Envestra has derived an estimate of the WACC, which it considers to be the minimum necessary to provide the necessary incentive to ensure that essential on-going investment in gas distribution networks is maintained.

A2. BACKGROUND

In its 1998 Final Decision[1] ('*Final Decision*') the Regulator expounded a regulatory framework for the Victorian natural gas distribution industry. Since that time the Regulator has significantly modified its approach and/or interpretation of many of the key factors that underpinned the Final Decision. During that time it has become apparent that many regulatory decisions have been to the detriment of the distribution businesses' shareholders. Almost all of the regulatory interpretations and amendments (proposed or actual) have had the effect of reducing returns to shareholders (e.g. GST pass throughs of less than required to maintain economic neutrality, changes made by the Regulator to the return on assets calculation etc). This has created a great deal of uncertainty and risk for investors. This risk was not compensated for in the 1998 Final Decision.

Furthermore, the regulatory framework confers asymmetric risk upon distribution businesses which was not appropriately incorporated into the 1998 rate of return. An imperative of the Regulator, in the 2003 Gas Access Arrangement Review ('GAAR'), must be to rectify the asymmetric risk imbalance and move towards a regulatory framework that is sustainable over the long-term. An important step towards this will be to determine a WACC that provides investors with a rate of return commensurate with the risk adjusted opportunity cost.

In an interview with the *Australian Financial Review* published on 25 February 2002 Mr John McFarlane, Chief Executive of Australia and New Zealand Banking Group Ltd voiced his views on the current regulatory framework for the banking industry in Australia. The regulatory arrangements governing banking and gas distribution differ in many respects, but there are common views from the respective regulators about the cost of capital - that is, the cost of capital is the appropriate rate of return that should be allowed on investments by regulators. Mr McFarlane's views on the Australian regulatory environment are summarised below:

- over-regulation harms business investment;
- over-regulation will make Australia an unattractive destination for investment funds;
- investors do not like overly regulated markets;
- investors do not like unfairly regulated markets;
- prices that either fall too quickly or are set too low have negative affects for the economy as a whole; and
- businesses need to earn more than their cost of capital to remain viable.

[1] Office of the Regulator-General, *Access Arrangements –Multinet Energy Pty Ltd & Multinet (Assets) Pty Ltd, Westar (Gas) Pty Ltd & Westar (Assets) Pty Ltd, Stratus (Gas) Pty Ltd & Stratus Networks (Assets) Pty Ltd Final Decision*, October 1998

Others have echoed Mr McFarlane's views, most notably financiers, industry leaders and the Productivity Commission in their 2000-01 Annual Report. In a recent review of the National Access Regime the Productivity Commission found that the regulatory environment[2]:

- can produce inefficiencies;
- is subject to various forms of bias;
- can involve significant intrusion into the property rights of facility owners; and
- requires modification to reduce the risk of regulatory error and overreach in order to ensure a long-term pay-off to the community.

Moreover, the Productivity Commission concluded that the major risk associated with regulation of infrastructure is that setting low prices could deter investment and that consumers will be worse off than had regulated prices been set higher. Other negative effects of low access pricing were found to be inefficient entry into upstream or downstream activities and inefficient investment in network extensions.

> "*In the long-term, consumers and business users will be worse off without an essential infrastructure service than if the service was provided at higher prices."*[3]

> "*The [Productivity] Commission's recent inquiries have revealed a need to re-balance the emphasis away from achieving immediate gains for users and consumers from existing infrastructure – much of it government owned or previously government owned – to a regulatory framework that will also facilitate efficient investment in augmented and new facilities. In this way, pro-competition regulation is more likely to ensure that Australia has modern infrastructure which is provided and used efficiently, with long-term benefits to the Australian community.*"[4]

> *"….the costs of failing to invest in essential infrastructure are likely to be larger than the costs of monopoly pricing of services it provides. Hence, it is crucial that access regulation gives proper regard to incentives to invest"*[5]

The Productivity Commission provided a comprehensive analysis of the factors affecting investment in regulated infrastructure. The regulatory risks identified by the Productivity Commission were:

- the costs of regulatory error can be substantial where long-lived investments are concerned (such as gas distribution pipelines);
- regulators aiming for an ideal but unattainable outcomes;

  (Envestra notes than an example of this from the Victorian regulatory regime includes the setting the regulated return equal to the theoretical cost of capital and the theory of perfectly competitive markets. A more pragmatic application of economic theory is essential.)

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2 Productivity Commission, *2000-01 Annual Report*, pp 4-16

3 Productivity Commission, *2000-01 Annual Report*, pp 10

4 Productivity Commission, *2000-01 Annual Report*, pp 15-16

5 Productivity Commission: *Review of the National Access Regime*, *Position Paper*, March 2001, pp11.

- regulatory intervention dampens incentives for cost saving, innovation and entrepreneurship not only in regulated firms but also those that depend on them;
- systematic regulatory error, such as biases towards the interests of current consumers over the interests of future consumers.

  (Envestra notes an example from the Access Code is that New facilities Investment can only be added to the Capital Base under section 8.16(b)(i) of the Code where the Anticipated Incremental revenue exceeds the New Facilities Investment. New Facilities Investment in excess of this is placed in a Speculative Investment Fund. This provision tends to deter regulated businesses from building sufficient capacity to meet demand that may occur outside the immediate planning horizon but which could not be said to be 'reasonably anticipated'. Although the Access Code allows Service Providers to seek the Regulator's approval that New Facilities Investment meets 8.16(b)(i) this requires a re-opening of the Access Arrangement and invokes the Access Codes' lengthy public consultation processes. The net effect is that businesses are incentivised to make investment decisions using relatively short planning horizons, which reduces opportunities to achieve economies of scale and ultimately increases long term tariffs for Users).
- the difficulties faced by regulators in distinguishing between monopoly profits and due rewards for risk taking (i.e. normal profits). Appropriate returns from successful risky investments will be truncated effectively penalising investors. However, investors bear all of the risks associated with project failure and/or poor returns (i.e. the coin tossing analogy where if heads come up investors breakeven or if tails investors lose). Rational investors recognise the difference between a random event and a biased game where adverse changes are intentionally imposed. Regulated businesses will therefore only invest in assets where there is no downside risk, which distorts investment decisions and resulting in an inefficient allocation of resources.

The underlying theme from the Productivity Commission's analysis was that regulatory risk is real, asymmetric and must be compensated for through higher investment returns to infrastructure owners. Moreover, low prices in the short-term are at the expense of long-term industry viability and service provision. The fact that a consistent message is emanating from respected business leaders, foreign governments[6] and independent Commonwealth government agencies requires the Regulator to fully account for these issues when determining the cost of capital for gas distribution businesses. With this as a background, Envestra's views on appropriate WACC parameter values are discussed below.

[6] Consulate General of the United States, *Public Submission re: the Dampier to Bunbury Natural gas Pipeline (pipeline licence no. WA:PL40) Draft Decision*, http://www.offgar.wa.gov.au/library/USConsulate.pdf.

A3. PRE OR POST TAX WACC

Envestra favours the real pre-tax approach to WACC for the reasons outlined in its *Reply to the Office's Position Paper of 7 September 2001*, dated 30 October 2001. However, given the fact that Envestra's previous submissions have not been able to move the Regulator from its position, it is clear that the Regulator will use the post-tax approach to the cost of capital in the Gas Access Arrangement Review. To participate in the cost of capital debate, Envestra has no alternate but to comply with the Regulator's wishes and submit a post-tax cost of capital. This does not in any way imply that Envestra accepts the Regulator's reasoning for the post-tax approach. Envestra continues to be of the view that a real pre-tax WACC is less intrusive and more consistent with the overall regulatory framework set out in the Access Code compared to the post-tax approach.

A4. CALCULATION OF THE WACC

Envestra's derivation of each of the WACC parameters is contained in section A5. Mathematically, the real post-tax WACC formula is expressed as follows.

WACC (real, post-tax) $= R_e \times \frac{E}{V} + R_d \times \frac{D}{V}$

Where:

R_e	Cost of equity which represents the post-tax return on equity calculated using the CAPM as follows: $R_e = E(R_i) = R_f + \beta_i[E(MRP_m)]$
$E(R_i)$	Expected return on asset *i* (or the cost of equity)
E	Assumed level of equity
D	Assumed level of debt
V	Sum of assumed debt level plus assumed equity level (V = D + E)
R_f	Real risk-free rate of return
D_m	Debt risk margin above the risk free rate
R_d	Cost of debt ($R_f + D_m$)
$E(R_m)$	Expected return on the market portfolio
$E(MRP_m)$	Expected Market Risk Premium and is calculated as $E(R_m) - R_f$.
β	Beta represents the sensitivity of the individual security relative to the market as a whole (equity beta (β_e)). Asset beta (β_a) has the effects of financial risk removed from the β_e through the use of the relevant de-levering formula. The systematic risk of asset *i* calculated as $\frac{\mathrm{cov}(R_i, R_m)}{\sigma_m^2}$
β_d	Debt beta (β_d) represents the sensitivity of the company's debt (risk margin) to the overall debt market

Table 1 Calculation of the WACC

A5. WACC PARAMETER VALUES

Being a small open economy, the cost of capital in Australia is subject to price competition and therefore competitively determined. Given the level of equity investment in Australia by non-residents, which stood at 28% of the total market capital on issue at 30 June 2001, and the discretionary nature of foreign investment (i.e. theory tells us that discretionary investment will only occur when return expectations are satisfied), it is evident that the class of investors that set the cost of capital in Australia are non-residents. This is consistent with the observation that the Australian stock market moves in tandem with capital flows of foreign investors and events on Wall Street[7]. With this in mind, Envestra provides indicative estimates for the key parameters for input into the WACC calculation below.

A5.1. Capital Structure (D, E)

Gearing is defined as the ratio of debt to total capital. Gearing provides the necessary weightings for the construction of the final WACC. The gearing ratio also affects the financial risk of an enterprise, which in turn is a determinant of the credit rating. The credit rating is used by lenders to price debt. Envestra proposes a commercially appropriate long-term average gearing level of 60 percent, the level consistently adopted in all Australian regulatory decisions.

A5.2. Cost of Equity (E (Ri))

The CAPM provides a guide to the risk adjusted return on equity compared to the return on risk free assets. The cost of equity relates to the rate of return required to attract and maintain equity in a business. The theory underlying the CAPM is that it is a forward looking measure of the cost of equity that requires estimation of the risk free rate, the expected return on the market portfolio and a measure of beta and is given by.

$$E(R_i) = R_f + \beta_i[E(MRP_m)]$$

There is an assumption in CAPM that the probability distribution underlying beta is normal and CAPM parameter values are typically estimated from historical data. Inappropriate historical data can lead to poor model performance, hence the need for relevant and suitable data[8]. Many of the parameter inputs cannot be estimated with accuracy, and hence require subjective assessment. However, the Regulator's approach to the cost of capital is theoretical and mechanistic, implying a great deal of precision in the outcome. The Regulator and other

[7] Ping W X, Variance *Decomposition of stock returns and dividend imputation system*, Applied Financial Economics, 1999, 9, pp 539-543

[8] Brailsford T J, Faff R W and Oliver B R, *Research and Design Issues in the Estimation of Beta*, McGraw-Hill Series in Advanced Finance, Vol 1 pp4.

regulators appear to be applying the CAPM as if it were deterministic. However, this view is not supported by the Monopolies and Mergers Commission (UK) (now the Competition Commission) or institutional investors:

"*…we do not believe the CAPM approach can be applied with precision, or in isolation*."[9]

"*Any outcomes from the CAPM should be benchmarked against the market generally to ascertain if investors are actually prepared to invest on the same terms that theory suggests they should.*"[10]

Coupled to this is the need for regulators to be aware that the asymmetries inherent in their cost of capital determinations will result in the return on capital being below the expected cost of capital. The Chairman of the Productivity Commission highlighted this point in a recent speech:

"….[the Productivity] Commission has come to the view that special additional provisions will also be needed if new investment is not to suffer from an inherent regulatory tendency to truncate the up-side potential of a proposed investment, while allowing investors to bear all the downside risks.

Recent references by regulators to average rates of return earned by companies on the stock exchange underline this problem. For example, if no project were allowed to earn more than the ASX average, then any proposed project with an above-average specific risk profile — requiring the possibility of above-average returns — would not proceed.

The problem of regulatory truncation is an important policy issue, but determining the best approach to dealing with it is not at all straightforward. It should nevertheless become a priority for government consideration and the Commission's final report on the National Access Review provides guidance on how it might go about it."[11]

To provide the appropriate drivers on Distribution businesses and to fulfil its obligations under the Access Code, the Regulator must:

- be mindful of its actions, as the effect of unexpected regulatory intervention tends to raise the cost of capital to the regulated firm[12];
- be conscious of the divergence of theory and reality; and

9 Monopolies and Mergers Commission, *BG plc, A report under the Gas Act 1986 on the restriction of prices for gas transportation and storage services*, May 1997, pp34

10 AMP Asset Management, *Submission to the Office of the Regulator-General regarding the Draft Determination of May 1998 on Victorian Gas Distribution Access Arrangements*, 29 June 1998.

11 Presentation to the IIR Conference, *National Competition Policy Seven Years On*, Eden on the Park, Melbourne, 14 March 2002.

12 Robinson T.A. *Modelling the effects of regulatory discretion: Carsberg vs Spottiswoode, Applied Financial Economics*, 2000, **1**0, 117-121

- not lose sight of the overall objective, which is to provide a rate of return that does not distort investment decisions and provide an incentive to develop the market for Reference Services

Therefore, Envestra recommends that the results from the CAPM be just one input into defining an appropriate cost of capital. Regulators must reality test the outcomes of their cost of equity estimates in capital markets and not become focussed on the misleading precision implied by the application of theoretically pure economic models such as CAPM. Furthermore, the selected rate of return must not impede efficient investment. The empirical and anecdotal evidence points to an appropriate return on equity being in the range of 12 – 15 percent

Source	Return on Equity (% p.a.)
Australian Stock Exchange[13]	13.5%
Wayne Lonergan, JASSA	12% - 15%
Macquarie Bank	12% - 15%
Toronto Dominion Bank	13% - 15%
AMP Asset Management	13%
Commonwealth Government Capital Usage Charge (see below)	12%
Michael Annin[14]	13%-19%

Table 2 Return on Equity required by Investor

The Commonwealth Government's Capital Usage Charge is the return it requires from its agencies for the use of funds invested by the Government.

"*This compensation reflects the returns the Commonwealth could get if the funds were not tied up in a given entity…..The Capital Usage Charge is a levy that an agency is required to pay to compensate the Commonwealth for the use of the equity funds invested by the Commonwealth in the agency. The rate is based on the return on a risk free investment plus a margin for risk. Currently this is set at 12%.*" [15]

Given that the Commonwealth government expects a return on equity of 12% (via its Capital Usage Charge) from its activities, it is not unreasonable to assume that private equity investors would expect a higher return from riskier investments in gas distribution businesses.

These findings imply that parameters should be selected in the upper end of the reasonable range. Moreover, managers prefer to avoid marginal projects (*i.e.* where the IRR is close to the cost of capital) and avoid the risk of a bad investment that destroys economic value[16]. Shareholders appoint directors,

13 http://www.asx.com.au/about/pdf/TowersPerrinl2001.pdf

14 Annin M, *Fama-French and Small Company Cost of Equity Calculations*, Business Valuation Review, March 1997.

15 source: http://www.finance.gov.au/budgetgroup/other%5Fguidance%5Fnotes/ownership.html "

16 Anderson R, Byers S, Groth J, (2000) *The cost of capital for projects: conceptual and practical issues*, Management Decision, 38/6, pp 384-

executives and managers to operate a business in accordance with their wishes. Any notion that managers of a company operate independently of shareholders is incorrect.

When these factors are considered together, in particular, the 12% Commonwealth Government Usage Charge it is clear that the appropriate return on equity should be at least 13%.

A5.3. Beta (β)

A5.3.1. Background

Three types of risk are generally associated with a regulated business. They are:

- systematic (beta) risk;
- company-specific (unique/diversifiable) risk; and
- regulatory risk.

Non-Diversifiable or systematic (beta) risk relates the systematic risk of a business to the risk of the financial market as a whole. It incorporates market wide factors such as the country's sovereign risk, legal, taxation and foreign affairs environment.

Specific risks are those risks unique to an asset or project. They are independent of the market. Company-specific risk relates to the size and nature of the geographic region in which the business operates, the demand and load growth risks (e.g. energy substitutability, price elasticities), customer profiles etc. Specific risk can be diversified away by holding a portfolio of assets. Therefore, specific risk is not reflected in the betas for the assets and is not incorporated into theoretically pure CAPM analysis. However, in practice investors tend to amend beta upwards to account for diversifiable risks.

Regulatory risk relates to regulatory uncertainty, bias and asymmetric events with respect to matters such as consistency, transparency, application of the Access Code, changes in policy and regulatory frameworks.

A given risk is often difficult to neatly categorised into one of these three categories (i.e. in reality, some company-specific risks have a level of market correlation – a beta effect). The compensation for these risks can be represented by an additional cash flow (such as a probability weighted cash flow in the Non-Capital Costs) and/or an increase in the WACC. Some of these risks are difficult to quantify and therefore difficult to model in the cash flows. Therefore, the adjustment will be two fold:

i) A positive adjustment to the asset beta for unquantifiable asymmetric firm specific and regulatory risks; and

ii) Inclusion in the cash flows for the quantifiable portion of asymmetric firm specific risks and self-insurance costs

The Regulator arrived at an equity beta of 1.2 in the 1998 Final Decision and stated:

"*Corporate finance theory indicates that investors require compensation through the cost of capital for systematic risk only. However, a number of submissions pointed to the established practice of including some allowance in the cost of capital for non-systematic or diversifiable risks (such as regulatory risk and the risk of major infrastructure dislocations) which cannot be readily quantified and included in the cash flows, as the theory would require. The beta value selected by the Office therefore consciously overcompensates investors for systematic risk, to recognise the existence of such diversifiable (or insurable) risks. In particular, the Office has been deliberate in selecting a beta estimate near the upper bound of the plausible range to give appropriate weight to the risks that are perceived to be associated with the immaturity of the regulatory regime and the Victorian gas market reforms, and the presence of insurable risks such as those associated with possible major infrastructure disruptions.*"

Indeed, the regulatory regime may have matured in terms of the number of years it has been in operation. However, the continuing gas market reforms, changes in regulatory interpretation and analysis, increasing regulatory intrusion and heavy handedness and the possibility of major infrastructure disruptions convey more risk now compared to 1998.

A5.3.2. Fundamental Beta Estimation

One way to increase the level of comfort with an estimate of beta is to consider its development from a number of different perspectives. The extent to which these independent estimates converge provides comfort (or otherwise) about the estimate. To this end, the beta of assets and equity can be developed from an estimate of its known determinants. The equity beta is a function of the underlying beta of revenue, the degree of operating leverage and the degree of financial leverage.

Just as the beta of equity is the beta of assets "levered up" by the proportion of fixed interest costs from financial leverage, the beta of assets can be viewed as the beta of revenue "levered up" by the proportion of fixed operating costs from operating leverage. While this estimation process (as well as regression methods) are subject to measurement error, in the end, the selected beta involves informed judgement.

The beta of revenue for gas distribution is expected to be relatively low (less than 0.3) but positive.[17] Revenue is a function of gas usage and prices, where the latter

[17] There are challenges in estimating this number. If price levels are regarded as unrelated to the economy then the beta of revenue will be a function of how volume covaries with the economy. In this regard, a regression of annual changes in Australian gas volumes (ABARE data)

is set by regulation and will vary with the economy in a lagged manner due to the incorporation of inflation (a systematic risk). The demand for gas over the existing network, is largely determined by the weather and overall economic activity in user industries. It is hypothesised that the beta of revenue for domestic customers is lower than industrial customers with commercial customers somewhere between the two. This is based on the following reasoning. The beta for domestic customers will be related largely to the extent that weather is a systematic risk. While low, it will be positive. The demand for industrial usage will be more influenced by macro factors than domestic usage, however it is not entirely independent of the weather.

Consequently the beta of revenue for industrial customers will be closer to one. Overall, the revenue beta should be positive but relatively low. By contrast, a margin on debt of 170 basis points is consistent with a beta of debt of 0.23 using a MRP of 7.3%. This can provide a guide to what to expect for the beta of revenue for gas distribution – it would not be expected to be lower than the systematic risk borne by debt-holders. The relationship between the beta of revenue and the beta of assets has been modelled as follows[18]:

$$\beta_{Asset} \quad = \quad \beta_{\mathrm{Re}\,v}\left(1+\frac{PV(FC)}{PV(Asset)}\right)$$

where PV (FC) is the present value of expected fixed costs and PV (Asset) is the present value of the operating cash flow stream.

The present value of the latter can be approximated by the replacement value of assets in a regulatory environment where the potential for any substantial positive NPV investments or activities are small and short-lived. The present value of fixed costs can be estimated from internal forecasts. Since gas distribution has a high proportion of fixed costs, the ratio of PV (FC) to PV(Assets) will be high. Estimates of this ratio for rail access and electricity transmission lie in the region of three.[19] Gas distribution is expected to be similar thus the beta of assets is likely to be around three to four times the beta of revenue. A beta of revenue in the range 0.15 to 0.25 (which is very low, and lower than the beta of debt noted above) will yield a beta of assets in the region 0.6 to 1.0. Even at 3 times, the beta of assets should be in the range 0.45 to 0.75.

This analysis suggests that an asset beta for gas distribution is likely to be greater than 0.5. Combined with financial leverage of 60% gearing, or D/E of 1.5, this suggests a beta of equity in the order of 1.25 using the following financial leverage relationship with beta of debt at zero:

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against changes in deflated GDP provides a slope of 0.79 for gas and 0.65 for electricity using data from 1982/3 to 1998/9. The 't' statistics were 2.35 and 4.01 respectively. More frequent observations (e.g. monthly) do not appear to be available.

[18] See Brealey and Myers, *Principles of Corporate Finance*, 6th Edition, Chapter 9 for a derivation and further explanation.

[19] Queensland Rail's submission to QCA estimates this value to be 3.1.

$$= \beta_a \left(1 \quad + \quad \frac{D}{E} \right)$$

The analysis also suggests that equity and asset betas should be positive i.e. any negative equity or asset betas do not make sense. A negative beta as an empirical outcome would have to be viewed with suspicion and may be either estimation error or a result of the CAPM not fully explaining capital market returns as noted earlier.

Other "fundamental" assessments of beta have led to the following views:

(i) Incentive-based regulatory regimes have higher betas than rate of return regulatory regime betas. This suggests that asset betas for gas distribution in Australia will be higher than the US where rate of return regulation often applies[20]. Thus comparable betas selected from the US need to be increased because of the different regulatory regime in place in Australia.[21]

(ii) In the 2001 review of Gas Distribution Access Arrangements, the Queensland Competition Authority concluded that gas distribution assets are systematically riskier than electricity distribution assets.[22] The QCA cites the World Bank, which found that '*gas utilities consistently had a higher asset betas than their counterparts in the electricity industry regardless of the form of regulation*'. Consequently, comparable electricity betas would be lower than gas distribution betas. This is consistent with the argument that the revenue beta should be higher for gas distribution than electricity as electricity is a necessity good, while gas consumption is a discretionary good. The ANU has recently published a report which indicates that "*Electricity demand is price and income inelastic, which is consistent with the existing Australian literature on electricity demand consumption. The income elasticies of natural gas and the miscellaneous fuels are, however, unity or greater, implying that at least natural gas might be a 'luxury' good".*[23]

Analysing an asset and equity beta for gas distribution from the fundamental determinants provides the following results:

(a) the asset beta for gas distribution is expected to be greater than 0.5 and a beta of equity is expected to be in the order of 1.25 for a gearing level of 60% (debt to debt plus equity);

20 See also ABN Amro cited above, pages 9 and 10.

21 Alexander I, & Irwin T, The World Bank Group: *Price Caps, Rate–of-Return Regulation, and the Cost of Capital*. Note 87, September 1996. This does not imply that regulatory risk within the context of a particular regime is market risk.

22 QCA: Final Decision*, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited*, October 2001, p373.

23 A. Muhammad, D. Stern The Australian National University, Centre for Resource and Environmental Studies, Ecological Economic Program: 'The Structure of Australian Residential Energy Demand'., p.17.

(b) equity and asset betas should be positive i.e. any negative equity or asset betas do not make sense;

(c) incentive based regulatory regimes have higher betas than rate of return regulatory regime betas; and

(d) gas distribution has higher revenue and asset betas than electricity.

A5.3.3. Empirical Beta Estimation

The market portfolio comprises all risky assets in existence[24] (i.e. residential and commercial property, shares in public and private companies, cash deposits etc.). A proxy for the market portfolio, is the stock market which is used to estimate the return on the market portfolio. There are a number of indices that could be used as the proxy for the market portfolio (eg ASX 200, All Ords index, All Ords Accumulation Index, AGSM Centre for Research in Finance index etc). Theory tells us that a value weighted index covering the broadest range of assets is the most consistent measure of the true market portfolio as defined in the theory of the CAPM[25]. The AGSM Centre for Research in Finance *Risk Measurement Service* market index portfolio contains all shares listed on the Australian Stock Exchange in value-weighted proportions adjusted for capitalisation changes and dividends. Hence, the *Risk Measurement Service* market index portfolio provides a superior measure of the market portfolio relative to the other proxies, such as the All Ords Accumulation Index etc., and will therefore provide higher quality estimates of beta.

The starting point in the analysis is usually to estimate an asset beta that considers the operational risk associated with the business (and assumes 100 percent equity finance). Asset betas for comparable domestic gas and electricity distribution businesses were calculated from empirical information obtained from the *Risk Measurement Service,* using data from the June 2000 and 2001 quarters, for:

1. AGL Ltd
2. Australian Infrastructure Fund Ltd
3. Envestra Ltd
4. United Energy Ltd

AGL owns the New South Wales natural gas distribution system as well as shares in various other pipelines in Australia and New Zealand and derives a significant portion of its revenue from these assets. Similarly, United Energy either wholly, or partially, owns energy distribution assets in Victoria and Western Australia in addition to retailing businesses. Envestra is predominantly a gas distribution business with a variety of assets throughout Australia. The Australian Infrastructure Fund can

24 Ibid, pp11

25 Ibid pp11

be considered a benchmark infrastructure investment company as it specialises in infrastructure investment and has in its portfolio a diverse range of regulated natural monopoly businesses (e.g. airports, rail, ports, energy infrastructure, roads and telecommunications). These companies are relevant points of reference when considering the appropriate value for beta.

AlintaGas, Australian Pipeline Trust, Contact Energy, Origin Energy, Horizon Energy, Advance Energy Systems were all precluded from the analysis as they were all listed within the past two years and did not have enough data to generate valid beta estimates[26]. Energy Developments Ltd, Pacific Energy, Pacific Hydro, Renewable Energy Corporation and Envirostar were not used as a substantial proportion of their operations were not gas and/or electricity distribution.

To account for the mean reverting nature of observed equity betas the Blume adjustment[27] was applied to the 'raw' *Risk Measurement Service* equity beta estimates. This adjustment is consistent with recent research that shows that the reversion to the mean may be a real and a managed outcome rather than just a statistical measurement error phenomenon[28]. The adjusted *Risk Measurement Service* equity betas were then used to derive the asset beta using the Brealey Myers de-levering formula[29]:

$$\beta_a = \frac{\beta_e + \beta_d \times \frac{D}{E}}{1 + \frac{D}{E}}$$

The value of debt (D) and the value of equity (E) for each of the four comparators was measured as the three year average of (Book value of net debt) / (Book value of net debt + market capitalisation)[30]. The debt beta (β_d) represents the sensitivity of debt (risk margin) to the overall debt market, but is not directly observable. In the 2001 EDPR it was assumed to be in the range of zero to 0.2, IPART used a value of 0.06 in its July 2000 Final Decision for AGL Gas Networks, the QCA estimated the debt beta to be 0.26 by deriving it from the CAPM[31] for the Queensland gas distribution networks and OffGAR used 0.2 for AlintaGas in its June 2000 Final Decision. Envestra estimates the debt beta to be 0.23 using the following formula:

$$\beta_d = \frac{R_d - R_f}{MRP}$$

[26] *Risk Measurement Service* require at least 20 monthly observations to generate beta estimates

[27] Blume adjusted equity beta = Raw beta x 0.67 + 0.33

[28] Reserve Bank of Australia, *Systematic Risk Characteristics of Corporate Equity*, Research Discussion Paper 9802

[29] Brealey R, Myers S, Partington G, Robinson D (2000) *Principles of Corporate Finance*, 1st Australian edition, McGraw-Hill Australia, pp 499

[30] Data obtained from Centre for Research in Finance

[31] Queensland Competition Authority, Final Decision, *Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited,* October 2001 pp225.

Taking into account empirical evidence and the approach adopted in other regulatory decisions, a debt beta in the range of zero to 0.23 has been used to estimate the asset beta.

The results from the asset beta analysis are presented in the table below and represent the mean values from the sample. The estimated asset beta is in the range of 0.45 to 0.62 for a natural gas distributor, with a mid-point value of 0.54, which has been used for calculating the re-levered equity beta.

Asset Beta Calculations	β_d **= 0.0**	β_d **= 0.23**
June Quarter 2000 Asset beta	0.51	0.62
June Quarter 2001 Asset beta	0.45	0.56

Table 3 Asset Beta Calculations

To derive the equivalent equity beta the estimated asset beta is then re-levered to derive the equity beta in the Brealey Myers re-levering formula using the efficient/benchmark gearing ratio of 1.5 (60:40 debt to equity):

$$\beta_e = \beta_a + (\beta_a - \beta_d) \times \frac{D}{E}$$

The table below shows the re-levered equity betas that correspond to the asset betas calculated above. The estimated equity beta is in the range of 1.05 to 1.28 for a natural gas distributor, with a mid-point value of 1.16. This is broadly consistent with the equity beta value of 1.2 determined by the Regulator in 1998. The equity beta of 1.16 has been used in the CAPM to derive the nominal post-tax cost of equity for use in the WACC equation.

Equity Beta Calculations	β_d **= 0.0**	β_d **= 0.23**
June Quarter 2000 Equity beta	1.28	1.20
June Quarter 2001 Equity beta	1.13	1.05

Table 4 Equity Beta Calculations

A5.4. Risk Free Rate (R_f)

The Regulator prefers to use a real risk free rate. In theory, the risk free rate applicable to calculating the cost of equity from CAPM should match the economic life of the investment. Investments in gas distribution assets can have economic lives of up to 100 years. In Australia the ten-year Commonwealth bonds are the longest duration bond available, with sufficient liquidity, to use as a proxy for the risk free rate. Therefore, Envestra proposes to use the 10 year Commonwealth bond interest rate adjusted by the mid-point of the Reserve bank of Australia's medium term inflation target of 2.5 percent per annum as the risk free rate in the WACC calculation.

To take account of potential volatility in interest rates and the practical difficulty of taking a spot measurement, bond yields were considered over a 20 working day period from 11 February to 8 March 2002. In this period, (nominal) 10 year Commonwealth bond yields ranged from a low of 5.95 percent to a high of 6.37 percent. The average nominal rate on 10 year Commonwealth bond yields over the 20 day period was 6.1 percent, which will be used as the risk free rate. The comparable real risk free rate of 3.5 percent is derived from the 20 day average nominal bond rate and the expected inflation rate using the Fischer equation.

A5.5. Market Risk Premium ($E(MRP_m)$)

The equity or market risk premium ('MRP') is a measure of the premium associated with holding a market portfolio of investments. The premium measures the difference between the expected return from holding such investments and the risk free rate.

There are two main methods used to estimate the MRP - historical averages and theoretical ex-ante economic models. Envestra notes that there have been a number of studies using both MRP estimation methodologies that calculate the MRP to be in the range of 3.5 to 8.0 percent.

A5.5.1. Historical Estimate of MRP

Historical MRPs vary according to the length and period over which the data are observed. Brealey, Myers *et al* (2000) suggest an 8 percent MRP for Australia[32]. The average annual Australian MRP from 1883 to 2000, as measured by the average annual excess returns from holding shares, using the All Ordinaries Index, compared to 10 year Commonwealth bond yields, was 7.3 percent[33]. A comparable MRP of 7.1 – 8.6% percent from 1900 to 2000 was found by Dimson, Marsh and Staunton (2000)[34], depending on whether the geometric or arithmetic mean was used. Recognising that historical estimates of the MRP were not strictly consistent with the CAPM, Dimson, Marsh and Staunton adjusted their historical MRP estimates downwards by their "best guess" of future equity market volatility levels to provide an estimate of the expected future MRP. Estimates of the expected future MRP for the United States, United Kingdom, Australia and an average of the 12 countries used in the sample, are presented below.

Country	*1900 – 2000 MRP*	*Expected Future MRP*
United States	7.7%	6.8%
Australia	8.6%	8.1%
United Kingdom	6.6%	5.9%
12 Country Average	8.1%	6.7%

Table 5 Market Risk Premium

In aggregate the twelve countries used in the Dimson, Marsh and Staunton (2000) analysis represent ninety percent of world market capitalisation. Other evidence also supports an MRP in the 7% - 8% range[35,36], as can be seen in the graph from the Welch (2000) study.

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32 Brealey R, Myers S, Partington G, Robinson D (2000) *Principles of Corporate Finance*, 1st Australian edition, McGraw-Hill Australia, pp 166.

33 Gray S, (2001) *Issues in Cost of Capital Estimation*, http://www.reggen.vic.gov.au/PDF/2001/SubUQBS_GasPosPapOct01.pdf

34 Dimson, Marsh and Staunton, *Risk and Return in the 20th and 21st Centuries*, Business Strategy Review, 2000, Vol 11, Issue 2.

35 Welch, Ivo, (2000), *Views of Financial Economists on the Equity Premium and on Professional Controversies*, Journal of Business, 73, 4, 501-537

36 Ibbotson Associates, (2001), *International Cost of Capital Report 2001*, http://valuation.ibbotson.com.

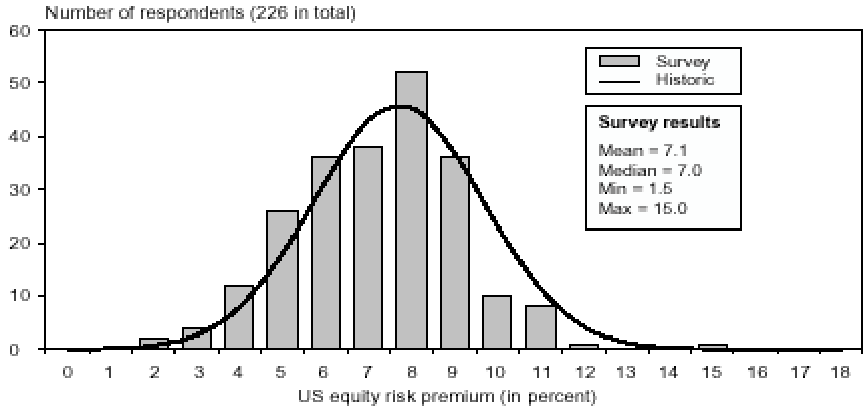

Figure 1 US Equity Premium

A5.5.2. Ex-Ante Estimate of the MRP

There are a number of ex-ante MRP forecasting methods. The two main ones being subjective estimates based on relative risk factors and the theoretical Dividend Growth Model. Professor Bowman[37] recently estimated the forward-looking long-term Australian MRP to be 7.8% and 9.2% for a short-term horizon after adjusting the US MRP for differences in taxation, equity markets, time horizon and country risk. Other ex-ante estimates have ranged from 3% to 4%.

Theoretical ex-ante MRPs are a product of the assumptions made about dividend yields, dividend growth, tax rates and inflation – all variables that are highly uncertain and difficult to forecast accurately. To demonstrate the variability of the parameters required for the ex-ante MRP models the graph below shows dividend yields, GDP (often used a proxy for dividend growth) and inflation[38].

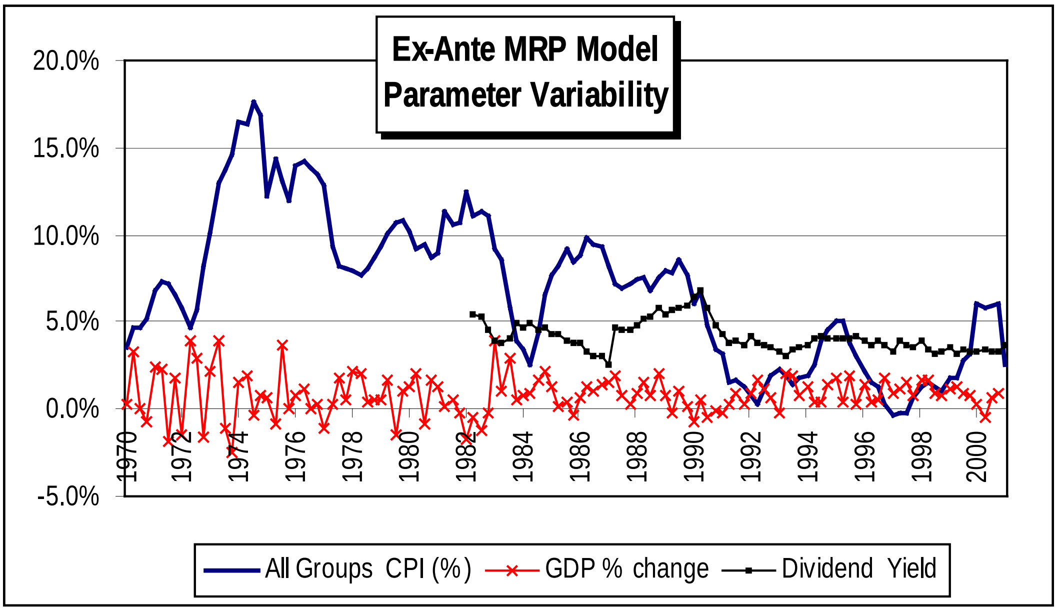

Figure 2 Ex-ante MRP Model Parameter Variability

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[37] Bowman R, *Estimating Market Risk Premium*, JASSA Issue 3, Spring 2001, pp 10-13

[38] all data obtained from http://www.rba.gov.au/Statistics/

Note: 1970 was the earliest CPI data available.

Statistical Analysis	CPI % p.a.	GDP % p.a.	Dividend Yield (% p.a.)
Mean	6.8%	0.8%	4.1%
Standard Deviation	4.3%	1.2%	0.9%
95% Confidence Range	-1.7% to 15.4%	-1.5% to 3.2%	2.4% to 5.9%

Table 6 Statistical Analysis of Input Parameters

The statistical analysis indicates that the variability surrounding each of the input variables is quite large, as evidenced by the standard deviations. The interaction of the variability between the ex-ante MRP model parameters is of serious concern for Envestra as it creates a great deal of uncertainty and provides the prospect of an arbitrarily determined MRP being used in the CAPM even though there is no empirical justification.

The theoretical ex-ante economic models have predicted the MRP to be in the low end of the quoted range. This is not surprising given stock markets around the world have been at record highs in recent years as well as a low inflation environment. However, Mehra[39] points out that.

"…after a bull market, when stock valuations are high relative to fundamentals the ex-ante equity premium is likely to be low. However, it is precisely in these times, when the market has risen sharply, that the ex-post, or the realized premium is high. Conversely, after a major downward correction, the ex-ante (expected) premium is likely to be high while the realized premium will be low. This should not come as a surprise since returns to stock have been documented to be mean reverting."

The augmented Dickey-Fuller test, which measures data variability, demonstrates that the Australian MRP is mean reverting, hence we would expect the same outcome to occur in Australia as discussed by Mehra (2001).

A5.5.3. Conclusion

The literature demonstrates that the most appropriate estimate of the MRP for use in determining the rate of return is the long-term average, as investors incorporate the past outcomes into their ex-ante estimates and long-term averages smooth out short-term fluctuations.

"While the concept of the WACC and its application for determining regulated revenues is unambiguously forward looking, estimates of the future cost of equity are not readily available. Practical applications of the CAPM, therefore, rely on the analysis of historic returns to equity to estimate the MRP..…any movement in the MRP can only be accurately determined by accessing changes in the market over an extended period of time."[40]

"The data used to document the equity premium over the past hundred years is as good an economic data set as we have and a hundred years is long series when it

[39] Mehra R, *The Equity Premium: Why is it a puzzle?,* http://www.econ.ucsb.edu/~mehra/papers.html, 6 October 2001, pp 21

[40] ACCC, Queensland Transmission Network Revenue Cap: Decision 2002 – 2006/07, November 2001, pp 13-19

comes to economic data. Before we dismiss the premium, not only do we need to understand the observed phenomena but we also need a plausible explanation as to why the future is likely to be any different from the past. In the absence of this, and based on what we currently know, we can make the following claim: ***over the long horizon the equity premium is likely to be similar to what it has been in the past****…...”*[41] [emphasis added]

“We do not believe that there is sufficient empirical evidence to support the alleged decline over recent years in the Australian market. ….. It is proposed that a market risk premium of 7% is more appropriate based on published research and given the absence of firm evidence regarding a downward trend in market risk premia in Australia”.[42]

“*Note that to get reasonable standard errors, we need very long time periods of historical returns. Conversely, the standard errors from ten-year and twenty-year estimates are likely to be almost as large or larger than the actual risk premium estimated. This cost of using shorter time periods seems, in our view, to overwhelm any advantages associated with getting a more updated premium.”*[43]

“You may ask why we look back over such a long period to measure average rates of return. The reason is that annual rates of return for common stocks fluctuate so much that averages taken over short periods are meaningless. Our only hope of gaining insights from historical rates of return is to look at a very long period. These are arithmetic averages.”[44]

The mean reverting nature of the MRP indicates that the long-term average MRP will provide the best unbiased estimate of the future MRP. The same cannot be said for theoretical ex-ante MRP models.

The inaccuracy and conjecture surrounding the theoretical ex-ante MRP models ascribes little confidence to the estimates of MRP that they provide. Indeed, they may in-fact provide biased estimates of MRP which are inconsistent with CAPM theory. Conversely there is a plethora of theoretical and empirical evidence supporting the use of the long-term average MRP as the best unbiased estimator of the expected MRP. Envestra has therefore selected the long-term average an MRP of 7.3 percent as the MRP for use in the WACC calculation. The estimate is based on the observed average annual excess returns obtained by holding shares compared to the 10 year Commonwealth bond rate over the period 1883 to 2000.

A5.6. Cost of Debt (Rd)

The pre-tax nominal cost of debt is most appropriately estimated by adding an appropriate debt risk margin to the risk free rate. The table below provides a summary of the debt risk margins used by Australian regulators in the recent past.

[41] Mehra R, *The Equity Premium: Why is it a puzzle?*, http://www.econ.ucsb.edu/~mehra/papers.html, 6 October 2001, pp 22

[42] Queensland Treasury Corporation, *Draft Decision on the Queensland Transmission Network Revenue Cap Response*, August 2001, pp 19.

[43] http://www.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf

[44] Brealey R, Myers S, Partington G, Robinson D (2000) *Principles of Corporate Finance*, 1st Australian edition, McGraw-Hill Australia, pp 165.

Regulatory Decision	Date	Debt Risk Margin
ACCC Draft Decision, Powerlink Queensland Electricity Transmission System	November 2001	120 basis points
QCA, Final Decision, Allgas Energy & Envestra Queensland Gas Distribution Networks	October 2001	155 basis points
QCA, Final Determination, Energex & Ergon, Queensland Electricity Distribution Networks	May 2001	165 basis points
ORG, Final Decision, Citipower, Powercor, TXU, UE, AGL. Victorian Electricity Distribution Networks	September 2000	150 basis points
OffGAR Final Decision, AlintaGas Perth Gas Distribution Network	June 2000	120 basis points
IPART Final Decision, AGLGN NSW Distribution Network	July 2000	90 - 110 basis points
ORG, Final Decision, Stratus, Westar, Multinet Victorian Gas Distribution Networks	October 1998	120 basis points

Table 7 Cost of Debt

In the EDPR[45] the ORG concluded that the appropriate debt risk margin was 150 basis points. The Regulator took submissions from a wide range of capital market participants who submitted that the debt risk margin for a business with a BBB credit rating would attract a debt margin in the range of 140 to 178 basis points.

The ACCC Powerlink decision was interesting insofar as the ACCC provided little evidence to support the case for its decision and disregarded capital market evidence that demonstrated that the appropriate debt risk margin for long dated BBB rated debt was in the range of 160 to 200 basis points[46]. For example, SPI Powernet and Queensland Treasury Corporation submitted the following:

…underwriters and investment bankers suggest that a debt margin of 180 to 200 basis points would be more realistic for the BBB to BBB+ long-dated debt rated issues of infrastructure groups such as Powerlink….[47]

Southcorp (rated BBB+) issued debt at a margin of 167 basis points. QTC believes that an appropriate range would be 120 to 200 basis points (assuming ten-year funding) for Powerlink given its notional credit rating and the available evidence. Given this range, a debt margin of 160 to 180 basis points would seem more appropriate.[48]

[45] Office of the Regulator-General, *Electricity Distribution Price Determination 2001-05*, Volume 1 Statement of Purpose and Reasons, pp 283-301.

[46] ACCC, *Queensland Transmission Network Revenue Cap: Decision 2002 – 2006/07*, November 2001, pp 17-18

[47] SPI Powernet, *Response to ACCC Draft Decision on Powerlink Revenue Cap*, August 2001.

[48] Queensland Treasury Corporation, *Draft Decision on the Queensland Transmission Network Revenue Cap Response*, August 2001, pp 16-17.

Envestra's experience in the capital markets and external advice[49] supports the QTC and SPI Powernet submissions, confirming that the appropriate debt risk margin is in the 160 to 200 basis point range.

Given our debt risk margin analysis and evidence from the capital markets, Envestra has determined that the appropriate debt risk margin be in the range of 160 to 180 basis points and has used 165 basis points as a point estimate.

A5.7. Inflation

Inflation is difficult to forecast, although forecasts are available from a number of sources. Envestra has adopted an expected inflation rate of 2.5 percent, which is consistent with the Reserve Bank of Australia's medium term target of 2 to 3 percent.

A5.8. Summary of Outcomes

The tables below summarise the input parameters for the WACC calculation and the resultant WACC proposed:

WACC parameters	Value
Expected Inflation (for WACC)	2.50%
Debt	60%
Equity	40%
Risk Free Rate	6.1%
Asset Beta	0.54
Equity Beta	1.16
Market Risk Premium	7.30%
Debt Margin	1.65%
Real Post-Tax WACC	7.9%

Table 8 WACC Parameters

Envestra has estimated a real post-tax WACC of 7.9 percent for the Victorian network.

49 Advice was received confidential-in-confidence advice from two well credentialled investment banks operating in the Australian capital markets. This has been provided to the Regulator on a confidential basis to protect the commercial activities of those institutions.

ATTACHMENT B

VALUE OF IMPUTATION CREDITS (GAMMA)

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B1. INTRODUCTION

The dividend imputation tax system provides shareholders with a tax credit that can be used to offset personal income tax. The value of imputation credits is an estimate of the worth investors place on those credits.

Estimating the value of imputation tax credits is complicated by several factors, including that:

- It involves estimating an unobservable expected value;
- The estimation process relies on historical information;
- There is no general agreement on how to estimate the market value of imputation tax credits, and any method can contain potentially large estimation errors; and
- Different types of investors will place a different value on imputation tax credits.

Despite these difficulties, it is apparent that:

- The CAPM attempts to estimate the required rate of return of the marginal investor (i.e. the last investor willing to contribute funds to the firm);
- The empirical evidence that is used to estimate cost of capital parameters (e.g. risk free rate, market risk premium, debt margin, equity beta) reflects the behaviour of the marginal investor;
- The appropriate value of imputation tax credits is that which is attributed to them by the marginal investor in the firm;
- The nature of the marginal investor is an empirical question.

The question of what value to attribute to imputation credits is therefore: What proportion of taxes paid at the corporate level is pre-collection of the personal tax of the marginal investor in the firm?

B2. KEY ISSUES

The value of imputation credits is defined as:

$\gamma = (f \text{ x } \omega)$

Where f is the fraction of current imputation credits that the firm distributes, and ω is the value of imputation credits expressed as a percentage of the credits' face value to shareholders when distributed[1].

Historically, regulators have placed a value on imputation credits (gamma) equal to 0.5. However, this value and its purported effects on the cost of capital, does not take into consideration other tax reforms implemented at the time imputation commenced (e.g. Capital Gains Tax). Viewed in isolation the impact of dividend imputation downwardly biases the cost of capital, which unduly penalises investors.

There is also mounting evidence demonstrating that the marginal investor, who determines the equilibrium price in capital markets is a foreign investor or an institution, who is unable to benefit from imputation credits.

This implies that the value of imputation credits are likely to be zero and certainly not 0.5 as assumed in previous regulatory decisions.

Envestra has assessed the value of dividend imputation credits (ω) taking into account these factors and concludes that the value of dividend imputation is zero[2]. These argument are discussed below.

[1] Brealey R, Myers S, Partington G, Robinson D (2000) *Principles of Corporate Finance*, 1st Australian edition, McGraw-Hill Australia, pp 585-586.

[2] Cannavan D, Finn F, Gray S, (2001), *The Value of Dividend Imputation Tax Credits,* Working Paper, University of Queensland Business School and Fuqua School of Business, Duke University.

B3. THE INTRODUCTION OF DIVIDEND IMPUTATION

In September 1985, significant changes were made to the taxation of equity investments. Assets acquired on or after 20 September 1985 became subject to a tax on capital gains (Capital Gains Tax or CGT). At the same time, complementary and offsetting reforms on equity taxation were announced, which resulted in the introduction of the dividend imputation system. Dividend imputation reduces the tax payable on dividends to a narrow class of investors. Viewed in isolation, the introduction of imputation may appear to have lowered the cost of equity, but only to a very narrow class of investors. But when viewed correctly, as part of a package of complementary but offsetting reforms, a different picture emerges whereby the overall impact is neutral (at best).

Financial market commentators and the Reserve Bank of Australia suggests that the cost of equity might have increased as a consequence of these reforms to the taxation of equity:

"the package of tax changes that introduced imputation made a number of other changes including the introduction of a real capital gains tax. That is there was an offsetting change to the taxation of equity which by itself might have raised the cost of equity. One interpretation would be that dividend imputation has simply changed the incentive from paying out returns as capital gains which were untaxed at the personal level, to paying out dividends which are now also only taxed once. As it turned out, Australian stock prices actually fell on the day that dividend imputation (and the rest of the tax package) was announced, so this interpretation may not be entirely incrrect."[3]

"It is very hard to think of stocks for which there will be a positive reassessment flowing from the tax reform".[4]

These outcomes are consistent with the findings of Brealey, Myers *et al* (2000) where they discuss the history of dividend taxation and significance of the tax savings that resulted from the introduction of dividend imputation. They contend that the impact of dividend imputation was immaterial:

"Prior to [dividend] imputation, of the order of 70 per cent of dividends were received tax-free. These dividends went to tax exempt investors such as charities, to insurance company life offices who paid no tax on dividends and to companies. The inter-company dividend payments were subject to a tax rebate that effectively made them tax-free. This left the balance of 30 per cent of dividends taxable. Finding a means to aviod tax on these dividends was not a particularly difficult task. And in the 1970's and early 1980's tax avoidance was a major Australian sport. Most likely, this left taxes on dividends being paid only by public-spirited investors and small investors without the resources to engage in tax avoidance. Even for these investors there was a tax break. For a short period, which ended about two years before the introduction of imputation, there was a tax rebate on the first $1,000 of dividend income. The effective tax savings from imputation may therefore have been quite small. Particularly when we remember that not all investors receive the benefits of imputation."

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[3] Reserve Bank of Australia, *The Cost of Equity Capital In Australia; What Can We Learn From International Equity Returns?, RDP 9107*

[4] Australian Financial Review, 23 September 1985, pp 64

Hence, taking into account the findings of Brealey, Myers *et al*, the Reserve bank, and the opinion of the financial press, the value of imputation credits expressed as a percentage of the credit's face value to shareholders when distributed (ω) is insignificant, resulting in a negligible value from imputation credits. From both policy and practical viewpoints dividend imputation has not reduced the cost of capital.

B4. THEORETICAL EXPECTATIONS

Professor Stephen Gray has discussed the theory behind equilibrium in Australia's capital markets[5]. The basic economic notion of equilibrium suggests that assets will end up being held by those who value them most. The ACCC recognises that shares in Australian companies will potentially be of more value to domestic investors than to foreign investors. This is because foreign investors will receive returns in the form of dividends and capital gains, but domestic investors will also receive the benefits of dividend imputation credits. This means that domestic investors will be prepared to pay more for the shares than will foreign investors. If all of this is taken as given, two equilibria are possible:

If there is enough domestic capital available, all of the shares will be held by domestic investors and the share price will be bid up so that dividends plus capital gains plus imputation credits jointly provide the required return to investors.

If, however, there is insufficient domestic capital available, some foreign investment will be required. Or course, foreign investors will only provide capital if they receive their required return. This implies a lower share price such that dividends plus capital gains provide the required return to foreign investors. In this scenario, foreign investors receive their required return and domestic investors receive a return that is above what they require. In particular, domestic investors receive the required return from dividends and capital gains (as do foreign investors), and they receive additional value from imputation credits.

The ACCC argues in favour of the first equilibrium, where domestic investors hold all of the shares. This is in spite of overwhelming empirical evidence to the contrary. The fact that we see large amounts of foreign investment implies that foreign investors receive a fair return from their investments in Australia. The ACCC states that foreign investors "will either sell their shares or accept a lower rate or return". Clearly, they have not sold their shares. Thus, the ACCC explanation is that foreign investors are happy to contribute funds to Australian firms even though they receive something less than their required return. This is patently inconsistent with even the most basic notion of economic equilibrium. A standard Nash Equilibrium is defined as a situation in which no agent can improve their position by altering their strategy. In this case, it would seem obvious that foreign investors could improve their position by exiting Australia and investing in any other country in which their required return is available. Why would foreign investors voluntarily invest in assets that do not generate their required return from them? Or course, they would not. The reason we observe significant foreign investment in Australia firms is that foreign investors receive their required return. Moreover, if foreign investors were paid less than their required return, Australian firms would be worse off as they would be undercapitalised. Thus, the "equilibrium" impact in the ACCC's comments is not an equilibrium at all.

Moreover, the *marginal* shareholders is not the *average* shareholder. The marginal shareholder who sets the firm's cost of capital is the last one willing to contribute funds to the firm. This shareholder will contribute funds and will just receive the required return on their investment. In the case of a firm with majority domestic ownership but significant foreign ownership, the marginal shareholder will be a foreign investor. The

[5] Gray S, *Issues in Cost of Capital Estimation,* 19 October 2001

domestic investors receive value from imputation credits but the foreign investor does not[6]. This point has also been made by Professor Bob Officer:

"In an economy whose capital markets are open to world capital markets, the price of real after tax cost of capital will be set by world supply and demand conditions. Moreover, in an open economy as small as Australia, in the context of world capital markets, is a price taker with respect to the real cost of capital."[7]

Thus, equilibrium occurs with foreign investors receiving just their required return and domestic investors benefiting from the additional value of imputation credits. This is consistent with the concept of equilibrium as neither class of investors can receive a better return in a similar investment elsewhere. These arguments are based on the economic concept of equilibrium. Ultimately, however, the identity of the marginal investor is an empirical question.

[6] Once again, the foreign investor may be able to extract some value from imputation credits, but these mechanisms are costly to implement so that the value of imputation credits to foreign investors is less than the value to domestic investors.

[7] Officer R R, "A note on the cost of capital and investment evaluation for companies under the imputation tax", Accounting and Finance, Nov 1988, pp 66.

B5. EMPIRICAL EVIDENCE

The empirical evidence considers the value of imputation credits from a number of different angles, including:

- Identifying the price setting investors.
- Holistic view of dividend imputation.

B5.1. Price Setting investor assumption

The empirical evidence cannot support assumptions made by regulators about the nationality of the relevant investor being domestic. Being a small open economy, the cost of capital in Australia is subject to price competition and therefore competitively determined. Given the level of equity investment in Australia by non-residents, which stood at 28% of the total share value on issue at 30 June 2001[8], and the discretionary nature of foreign investment (i.e. theory tells us that discretionary investment will only occur when return expectations are satisfied), it is evident that the class of investors that sets the cost of capital in Australia is non-residents. This is consistent with the observation that the Australian stock market moves in tandem with capital flows of foreign investors and events on Wall Street[9]. Hence, the cost of capital in Australia is set by non-domestic investors who value gamma at zero.

B5.2. Holistic View of Dividend Imputation

A paper provided in the Securities Institute of Australia Journal, (JASSA, Issue 1 Autumn 2001) by Wayne Lonergan demonstrates that the value of imputation credits for the marginal shareholder in the Australian share market is close to, if not, zero. Therefore the purported reduction in the market determined cost of capital due to dividend imputation is an illusion.

The key arguments presented in the Lonergan paper to support the proposition that dividend imputation has had a negligible impact on the after-tax WACC are:

(a) Individual Australian resident shareholders have benefited substantially following the introduction of imputation.
(b) The effect of dividend imputation on domestic companies has generally been neutral due to the inter-company dividend rebate pre-imputation.
(c) Foreign investors were relatively neutral to dividend imputation because many received a full credit in their own countries for either the underlying rate of tax or at least the withholding tax.

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[8] Australian Bureau of Statistics, *International Accounts and Trade Feature Article – Foreign Ownership of Equity (September 2001)*, ABS Cat, no 5302.0, September 2001.

[9] Ping W X, Variance *Decomposition of stock returns are dividend imputation system,* Applied Financial Economics, 1999, 9 pp 539-543

(d) The Australian share market represents about 1% of the total world's share market capitalisation. The Australian share market is insignificant in the global capital market. Given the relative freedom of global capital flows, Australia is a price taker in the global capital market.

(e) The price-makers in the Australian share market are the large investors, such as domestic institutional investors (e.g Superannuation funds, Life Insurance Companies) and foreign investors.

(f) The marginal shareholders in the Australian share market are the price-makers. The returns have not changed significantly pre and post imputation so the return they require on capital has not changed. Therefore, dividend imputation has had a negligible impact on the after-tax cost of capital.

(g) Returns in the Australian share market did not significantly outperform world equity markets following the introduction of imputation. All other things being equal, one would expect out-performance if imputation resulted in lower WACC leading to high equity valuations.

(h) Independent Experts Reports prepared in the context of company acquisitions do not support the adjustment to the WACC for dividend imputation. Given that Independent Experts Reports are often commissioned to assist company directors obtain a higher offer, one would have expected wide spread use of an imputation credit to the cost of capital in order to lower the discount rate and increase the valuation.

(i) From both international capital flow perspective and a local capital market perspective, the proposition that imputation has reduced the cost of equity capital in Australia can not be supported.

Lonergan concluded that the cost of capital had not reduced as a result of dividend imputation. To the extent that the regulators reduce the cost of capital for dividend imputation they are depriving investors of returns and distorting investment decisions. This will have serious negative long-term implications for the future availability of infrastructure, and will direct funds away to other alternative uses.

B6. CONCLUSION

The relevance of gamma in the cost of capital can only be assessed against the situation that existed prior to the introduction of capital gains tax and dividend imputation. The presence and extent of foreign equity investment in Australia proves that their cost of capital expectations are being met. As foreign investors do not benefit from the dividend imputation system it does not affect the cost of capital meaning that the value of gamma is equal to zero. Competitive market equilibrium and other empirical analyses support this outcome. Therefore, Envestra is of the view that an unbiased estimate of value of gamma is zero.

ATTACHMENT C

REGULATORY RISK

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C1 REGULATORY RISK

Regulatory arrangements impose a number of constraints on regulated businesses not encountered by non-regulated businesses (e.g. pricing constraints, service level obligations, public disclosure of commercially sensitive information). Regulatory decisions on these matters convey a special class of risk to shareholders of regulated businesses, namely regulatory risk. The two main manifestations of regulatory risk are:

(i) the basis for decisions implemented by the regulator may change over time, may not be anticipated by the regulated business and are biased against distribution businesses; and

(ii) asymmetric events that are not compensated for in the cash flows or the cost of capital.

Regulators have generally argued that regulatory risk is either immaterial, or that incentive regulation reduces risk because it enables regulated businesses to earn rates of return greater than the cost of capital. This is contrary to the Productivity Commission's finding that regulatory regimes are subject to various forms of bias[1]. As is demonstrated below shareholders need to be compensated for regulatory risk as it increases the overall risk profile of regulated businesses and is not captured by traditional CAPM analysis.

[1] Productivity Commission 2000-01 Annual Report, pp 1-16

1. C2 RISK AND BIASED DECISIONS

During the First Access Arrangement Period a number of the decisions handed down by the Regulator have unreasonably favoured existing consumers to the detriment of future customers, the distribution businesses and their shareholders. Examples of this bias in the First Access Arrangement Period are:

i) the return on assets calculation methodology proposed by the Regulator for the 2003 Access Arrangement is different to that used in 1998 and significantly reduces the dollar value of each distribution businesses return on assets;

ii) the GST *change in taxes* decision arbitrarily reduced pass throughs relative to these calculated by the MONASH model;

iii) the practice of truncating Reference Tariffs at the annual re-set instead of the usual business practice of rounding;

iv) the interpretation of the term ‘fair’ in developing efficiency sharing mechanisms as outlined in the ORG *Consultation Paper No 1*; and

v) large and retrospective increases in licence fees applying to gas distribution businesses which may not be recoverable.

C2.1 Return on Assets Calculation

The method proposed by the Regulator for calculating the return on assets component of Total Revenue for the 2003 GAAR is significantly different to the method used for the First Access Arrangement Period. The reasons for the change were not signposted in the lead up to the Access Arrangement Review and have never been communicated. The outcome is a lower return on assets of around $1.5 million per annum than would have been the case if the 1998 method continued. This flows directly through to lower Total Revenue and earnings. It would be reasonable for the acquirers of the Distribution businesses to expect that the return on assets component of Total Revenue would continue to be calculated in a fashion identical to the original method. This assumption was incorporated into the valuation and purchase price for Stratus Networks.

C2.2 GST Pass Through

The introduction of *A New Tax System* (NTS) in July 2000 required distribution businesses to apply to the Regulator for Reference Tariffs to be revised upward to accommodate the net impact of the GST. The Regulator specified the modelling and verification requirements distribution businesses were obliged to comply with to justify an economically neutral pass through of the net impacts of NTS.

To facilitate quantification of the net effect of NTS, Envestra engaged Deloitte Touche Tohmatsu (Deloittes) to independently determine the expected cost savings from the introduction of NTS and a corresponding pass through amount. Deloittes used the MONASH model to calculate the impact of NTS on individual commodity prices that were used to assess the impact of NTS on Envestra's cost base:

1. The savings on input prices that Envestra can expect as a result of the removal of several indirect taxes under NTS;
2. The costs incurred by Envestra to ensure that it complies with its obligations under NTS; and
3. The impact of the GST on the working capital of Envestra through the consequent changes to Envestra's cycle of cash payments and collections.

The MONASH model was developed by the Centre for Regional Economic Analysis, at the University of Tasmania. It is a dynamic computable general equilibrium model of the Australian economy designed for forecasting and policy analysis. It describes in mathematical terms the financial linkages between different sectors and markets that affect the Australian economy and how each of those sectors and markets responds to changes in policy. Three independent audits were undertaken to ensure the inputs, assumptions and outputs from the MONASH model were appropriate:

1. PricewaterhouseCoopers (PwC) was engaged by Envestra to verify the inputs and assumptions used in the modelling.
2. PwC verified that the MONASH model was used to estimate cost savings and that the assumptions adopted in the model were appropriate.
3. Deloittes verified that the models used by Envestra to calculate the GST pass-through were identical to the model verified by PwC.

Yet despite the rigorous and independent analysis undertaken, the Regulator did not allow the full pass through. The table below compares the pass through allowed by the Regulator and the pass through as calculated by the MONASH model and verified by Deloittes and PwC.

GST Pass Through	Regulator Pass Through	MONASH Pass Through
Jul-Dec 2000	9.93%	10.00%
2001	8.62%	10.00%
2002	8.54%	9.87%

Table 1 GST Pass Through Data

The pass through decision negatively impacted distribution businesses by more than $1 million per annum and can only be viewed as biased given the evidence presented to support the pass through.

Moreover, when improved economic data become available that demonstrated the GST induced component of CPI was lower than expected (0.25% in 2000/01), the ACCC informed Envestra that 2002 Reference Tariffs should be increased by 0.5% to account for the higher than necessary GST adjustment. The Regulator rejected an application by Envestra to adjust network tariffs accordingly. The rationale for rejecting the application was:

> *"The Commission is of the view that it does not have the power to vary its decision in relation to the change in tax pass through amount approved as a result of the introduction of the GST. The Victorian Gas Industry Tariff Order 1998 (the Tariff Order) provides the Commission with the capacity to make decisions when a change in tax event occurs. The Commission has a limited timeframe in which to make its decision. Having exercised its original power to make the decision in relation to the introduction of the GST, that power is now exhausted.*
>
> *Under the Tariff Order, the Commission only has the power to take into account under or over recoveries in relation to a previous change in tax decision when making a new change in tax decision*[2]."

C2.3 Truncation of Reference Tariffs

Reference Tariffs have been calculated each year according to the price control formula in the Tariff Order. The Regulator has introduced a practice of truncating tariffs at the fourth decimal place, instead of rounding. It is common practice to round prices and not truncate. The only outcome from tariff truncation is that Reference Tariffs are lower than if they were rounded. Distribution businesses are disadvantaged by this approach. This practice is biased against the distribution businesses.

C2.4 Fair Sharing of Benefits

The Regulator determined that a 'fair' sharing of the benefits of efficiencies derived by the electricity distribution businesses in the EDPR was 30:70 in favour of consumers and proposes to do likewise in the gas industry. Aside from the fact that this is inconsistent with the Fixed Principles, it is also inconsistent with any reasonable interpretation of the term 'fair':

> "*The meaning of "fairness" in business transactions is most clearly definable when referring to a moral obligation, which may also be a legal obligation, to avoid deception and to live up to previous commitments, expressed or implied. If judged by this test alone, any rule in rate making would be fair to investors, whatever its demerits on other grounds, if it conforms to the terms, on the faith of which the investment was originally made – fair no matter how onerous or how profitable these*

[2] Letter from the Regulator to Envestra dated 4 January 2002.

terms may prove to be in the light of hindsight (Bonbright 1961, 1270)[3].

All of the interpretations of the term "fair" are consistent except the one used by the Regulator in the EDPR. The efficiency sharing ratio of 30:70 in favour of consumers is clearly **not** fair and biased against the distribution businesses.

C2.5 Licence Fees

On 22 February 2002, the Minister wrote to Envestra advising that half-yearly licence fees would increase by some 260% to almost $1m on an annualised basis. Moreover, the increase was backdated to July 2001.

Such an increase in licence fees represents a significant imposition on distribution businesses that was not anticipated when the original Access Arrangement was prepared. The increase alone represents almost 0.75% of Envestra's total revenue. Further, the existing tax pass through clauses included in the Tariff Order may preclude Envestra from recovering this impost from customers.

The constraints placed on Envestra as a result of the regulatory regime clearly increase the risk that the business faces.

C2.6 Summary

These examples of bias are not exhaustive and represent a significant problem for the future users of Victoria's gas and electricity distribution infrastructure. Investors recognise bias and adjust their investment decisions accordingly, leading to reduced service provision. Consequently, the full implications of the negative biases will not surface until the medium to longer term.

Investors are not interested and/or do not understand the theoretical and often abstract concepts used by regulators to justify decrements to the regulated revenue. Investors focus on earnings and returns from their investment, which have declined with each of the regulatory decisions outlined above. Investors recognise the difference between a fair game and a biased game. Indeed, there are many other forms of investment that do not have regulatory risk and that are more readily understood by investors. These factors increase the cost of capital for regulated businesses.

[3] Kolbe L A, Myers S C, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Kluwer Academic Publishers, 1993, pp 9

C3 REGULATORY RISK AND THE PRICING OF ASSETS USING THE CAPM[4]

C3.1 CAPM and required return

The standard version of the CAPM relates the expected return on a stock ($E(R_i)$) to the expected market return ($E(MRP_m)$) a risk-free rate (R_f) and the stock's beta (β_i). As previously discussed CAPM is usually presented as follows:

$$E(R_i) = R_f + \beta_i[E(MRP_m)]$$

The CAPM represents a forward-looking model of security pricing (expected return) under conditions of symmetry in outcomes (being based on mean-variance analysis of market portfolios). It thus suggests an expected, but not guaranteed, return appropriate to the level of systematic risk taken on by the well-diversified investor. Alternatively, the cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. Thus the level of risk is intimately related to investors' required rate of return, however not all risks matter equally to investors[5]. The use of CAPM in determining the appropriate return on capital presupposes two important ideas:

i) all risks that are relevant to the investor are incorporated into the market's estimate of required return; and

ii) risks are symmetric in their impact (or that a symmetries will cancel out over a large portfolio).

To the extent that risks from economic regulation (i.e. regulatory risks) are not customary in the overall equities market, it may be argued that regulatory risks will not be incorporated into the market's estimate of the required return. Regulatory risk would thus be a form of non-diversifiable risk that would need to be compensated for in addition to market-determined returns on an asset.

Examples of asymmetric regulatory risks include:

- disallowance of capital expenditure under section 8.16 of the Access Code;
- disallowance of certain costs incurred in the operation of the business; or
- an absence of symmetry in the distribution of expected revenues, due to the imposition of price or revenue ceilings on the outputs of the regulated firm.

Each of these examples is asymmetric in that the regulated firm only faces a downside risk from the application of regulation (i.e. its returns will be reduced).

4 Envestra acknowledges the assistance of Ron McIver, Lecturer in Finance, School of International Business, University of South Australia, in preparing the regulatory risk section of the submission.

5 Kolbe L A, Myers S C, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Kluwer Academic Publishers, 1993, pp 129

C3.2 Regulatory risk and its impact on returns

To appreciate the impact of regulatory risk on the expected return to equity investors in the regulated firm assume that the return on capital expenditures is initially set to be in line with the CAPM determined required return ($E(R_j)^{CAPM}$).

In the absence of any disallowance of capital expenditure incurred by the firm, investors would expect to receive the regulated return $E(R_j)^{regulation}$ equal to $E(R_j)^{CAPM}$ in the future. However, if there is a non-zero probability that any component of capital is disallowed for inclusion in the regulatory capital base, and under the assumption that funds invested are recovered, the expected return to equity investors become as follows:

$$E(r_i)^{regualtion} = \left(\frac{K^{REG}}{K^{INVESTED}}\right) \times E(r_i)^{CAPM} + \left(\frac{K^{DIS}}{K^{INVESTED}}\right) \times 0\%$$

Conversely, where there is no recovery of funds invested, the return on investment will equate to:

$$E(r_i)^{regualtion} = \left(\frac{K^{REG}}{K^{INVESTED}}\right) \times E(r_i)^{CAPM} + \left(\frac{K^{DIS}}{K^{INVESTED}}\right) \times -100\%$$

Partial recovery of funds invested would see an expected return between these two extremes. Here K^{DIS} represents disallowed investment, $K^{INVESTED}$ the total funds invested and K^{REG} the regulatory capital base. In each case the disallowance of capital invested by the firm reduces the return on equity below the rate implied by the CAPM ($E(R_j)^{regulation} < E(R_j)^{CAPM}$). On any new investment, the risk of disallowance is asymmetric and an assessment of the size of K^{DIS} will be made according to the likely probability of disallowance of the planned capital expenditure.

Moreover, if Non-Capital Costs that satisfy the prudency test in section 8.37 of the Access Code are not allowed to be passed through into Reference Tariffs, then the Regulated return (($E(R_j)^{regulation}$) will be less than the CAPM determined rate of return ($E(R_j)^{CAPM}$). Two recent examples of this are the GST Pass Through and ESC Licence Fees. As Contractors, employees, debt providers *etc* all receive their payments before equity holders, any adverse (net) Non-Capital Cost outcomes are borne entirely by equity holders, thus reducing their returns below the regulator determined returns.

Regulatory risk is a special class of risk that must be recognised when setting the cost of capital[6]. The presence of regulatory risk requires the setting of a target return under regulation that is higher than the required return implied by CAPM to compensate investors for the expected losses due to the presence of regulatory risk. Inadequate incentives will produce sub-optimal investment outcomes where Distribution businesses will only invest when there is no material downside risk. The Chairman of the Productivity Commission has raised this point in his recent speech titled *Competition regulation of infrastructure: getting the balance right*[7], which drew on the policy discussion in the Commission's annual report for 2000-01.

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[6] Kolbe L A, Myers S C, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Kluwer Academic Publishers, 1993, pp 3-9

[7] Presentation to the IIR Conference, *National Competition Policy Seven Years On*, Eden on the Park, Melbourne, 14 March 2002.

C4. CONCLUSION

This Attachment has demonstrated both from an empirical and a theoretical point of view that regulated businesses are subject to considerable regulatory risk. The existence of regulatory risk places additional costs on the business that need to be taken into account by the Regulator when setting the cost of capital. Specifically, the rate of return approved by the Regulator needs to be higher than that required from applying the conventional CAPM model. Alternatively an allowance for regulatory risk needs to be included in the cash flows.

Attachment D

Verification of Demand Forecasts

April 2002

3 April 2002

Andrew Staniford
National Manager, Regulatory Affairs
Envestra Ltd
Level 10, 81 Flinders Street
Adelaide SA 5000

Dear Andrew

Independent Verification of Envestra's Gas Demand Forecasts

We have pleasure in enclosing our independent verification report considering the assumptions and methodologies undertaken for Envestra's gas demand forecasts. In our view, the assumptions and methodologies are consistent with ESC requirements. This report details our understanding of the forecasts and our findings.

We would welcome the opportunity to discuss our findings with you.

Yours sincerely

Stephen Weston Peter McNally Nghiep Luu

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Part I Executive Summary

Scope

Trowbridge Consulting Ltd (Trowbridge) has been retained by Envestra Ltd (Envestra) to perform a review of its demand forecast and provide an independent verification that the forecast meets the Essential Services Commission's (ESC) criteria.

The gas distribution industry in Victoria is regulated by the ESC in accordance with the provisions of the National Third Party Access Code for Natural Gas Pipeline Systems (the Code). On 2 April 2002, Envestra is required to lodge revisions to its existing Access Arrangements with the ESC. An important element of the Access Arrangement is the forecast of demand for gas. The Code provides that forecasts of demand must '*represent best estimates arrived at on a reasonable basis*'.

Further, the ESC has advised Envestra that, in reviewing its demand forecast, the ESC will examine whether the demand forecast meets the following criteria:

- has been applied in an unbiased manner (ie ensure due weight is given to the relevant factors);
- is appropriate to the situation and the nature of the gas market;
- recognizes and reflects key drivers of demand;
- is based on reasonable assumptions using the best available information;
- is assessed against existing forecasts and methodologies;
- uses the most recent data available and historic data that can identify trends in growth; and
- takes account of current demand and economic conditions and reasonable prospects for future market development.

We have reviewed the methodologies and assumptions used for the forecast and assessed whether they are consistent with the requirements specified in the Code and by the ESC. Our approach to this review has been consultative. In addition, where we believe Envestra's assumptions are subject to a larger degree of judgement we have arrived at a view as to whether that judgement has a material effect on the forecast.

In preparing demand forecasts, Envestra and the other Victorian gas distribution businesses have obtained independent advice on forecasts of key economic parameters that may influence the demand for gas. Trowbridge has not been required to provide verification of the value of these parameters. However, we have reviewed Envestra's use of all relevant economic parameters and verified that the methodology by which the parameters have been incorporated into the forecasts is consistent with the ESC criteria.

We have not reviewed the numerical accuracy of the forecasts nor have we checked that the forecast methodology has been implemented correctly.

Data Provided for our Review

In undertaking this review we have been provided with:

- A copy of the 8th draft of Envestra's forecasts;
- Relevant figures from the NIEIR economic forecasts used for the forecasts;
- relevant worksheets and model outputs;
- access to base data and documents used in preparation of the worksheets and models; and
- access to staff responsible for preparing the demand forecasts.

Our Review

We have reviewed the following methodologies and assumptions for consistency with the guidelines specified in the Code and by the ESC:

- An assumption that the expected number of EDDs during 2003 will be 1445, in line with the approach taken by VENCorp and Envestra's assumption that this will reduce by 5.5 EDD per year due to a warming trend;
- An assumption that the average weather normalised annual consumption for domestic customers will reduce by 0.2% each year;
- Envestra's model for individual distribution supply points (or DSP, which effectively is an individual customer) for Tariff V customers;
- For Tariff V customers we reviewed Envestra's approach for the following drivers of demand:
    - Forecast number of meter removals;

- Forecast numbers of new dwellings (Domestic Customers only);
- Forecast numbers of new connections for industrial and commercial customers based on analysis of historical trends (Industrial and Commercial (I&C) customers only);
- Assumed consumption patterns for new connections and meter removals;
- Changes in consumption per customer;
- Network marketing;
- Price elasticity of gas demand (and the impacts of FRC); and
- The relationship between Gross State Product (GSP) and consumption (I&C customers only).

- For Tariff D customers, we have reviewed:
  - the use of survey information to assess the likely future demand for existing customers;
  - the expected number of new customers each year based on historical trends and allowance for future trends; and
  - Envestra's view regarding the effect of GSP on Tariff D demand.
- We have reviewed Envestra's forecasts and methodologies against the approaches adopted by:
  - VENCorp in respect of its Annual Planning Review; and
  - The 1998 Access Arrangement review for the Victorian gas distribution networks, termed "Gascor's Forecast '97 methodology".

Our Findings

In our view, Envestra's methodologies and assumptions in relation to the gas forecasts meet the criteria specified by the ESC and the Code.

The following provides a brief summary of our main findings:

- In regard to the individual DSP model for Tariff V customers, our opinion that it represents a reasonable unbiased best estimate for the forecast demand for those customers is based on:

- Our review of the methodologies employed in the model based on discussions with Envestra and a demonstration of the main aspects of the model; and
- The fact that the model has been stress tested against actual data using two methodologies. The results of this analysis support the model as an appropriate forecasting tool.

- In regard to the adopted downward EDD trend assumption, we were satisfied that it is a reasonable assumption for the following reasons:
  - Analysis provided by VENCorp gives some credence to the downward trend even though VENCorp themselves do not incorporate it in their forecasts; and
  - Detailed analysis provided by CSIRO indicates that a downward trend is reasonable due to an expected warming trend in the future. CSIRO state that this trend is apparent both within and outside Melbourne.
- Our view is that the assumption that average demand per customer will fall by 0.2% per annum is reasonable for the following reasons:
  - It is supported by historical evidence; and
  - There are many valid reasons for this decrease to have occurred in the past and in our opinion, these reasons are also applicable to future demand.
- For Tariff V forecasts, most of the assumptions were based on the analysis of historical data. In our view, Envestra has chosen reasonable assumptions for Tariff V forecasts based on this analysis and the assessment of future trends.
- For Tariff D customers, we believe that the assumptions adopted are reasonable and provide a best estimate based on available information. While it is possible to apply other methodologies for the forecast of Tariff D demand, it should be noted that the forecasts for Tariff D are relatively less important than those for Tariff V because Tariff D customers provide only a small component of forecast revenue, given the current pricing structure.
- In our view, the methodology used by Envestra to generate the demand forecast is reasonable when assessed against existing forecasts and methodologies. In making this assessment we considered that the methodologies adopted by VENCorp and the methodologies adopted on behalf of the distribution businesses at the previous Access Arrangement review (Gascor's Forecast Methodology 1997) were the most appropriate comparisons. In making these comparisons, we have allowed for the

issues raised by direct comparisons between the forecasts, due to differences in their currency, purpose and, to a lesser extent, due to the recent revised approach to the impact of weather.

Reliances and Limitations

We have relied on the accuracy and completeness of all data and other information (qualitative, quantitative, written and verbal) provided to us by Envestra and its consultants and by other parties for the purpose of this review. We have not independently verified or audited the data. It should be noted that if any data or other information is inaccurate or incomplete, this report may need to be revised.

While due care has been taken in the preparation of the report, Trowbridge accepts no responsibility for any action which may be taken based on its contents.

This report has been prepared for the sole use of Envestra for the purpose stated in Section 1.1 of the report. No other use of, or reference to, this report should be made without prior written consent from Trowbridge Consulting Limited ("Trowbridge").

Any queries on the meaning of any figures or statements in this report should be referred to Trowbridge.

Our report should be considered as a whole. Members of Trowbridge Consulting staff are available to answer any queries and the reader should seek that advice before drawing conclusions on any issue in doubt.

- a small reduction in average usage associated with factors including reducing domestic use of gas appliances (including increased use of electric reverse cycle air conditioning), greater energy efficiency of existing appliances and reducing number of persons per household.

The prime drivers of demand by commercial and industrial customers include the number of new connections, general economic conditions, and the price of alternative fuels.

Forecasts for these customer groups are based upon NIEIR forecasts regarding economic activity and movements in electricity prices. In brief, NIEIR is forecasting a softening in Australian GDP growth over 2002-2003 due to:

- a decline in household consumer spending growth;
- fiscal tightening to curb the historic expansionary phase;
- the slowdown in housing construction associated with the winding back of the First Home Owner Scheme;
- stability or contraction in export levels; and
- rising unemployment.

However, a general recovery post-2003 is forecast consistent with world growth re-emerging, strong public sector finance levels and a recovery in mining and manufacturing projects.

Overall demand is forecast to increase by an average of 1.7% per year for Victorian Tariff V customers, reflecting primarily the addition of new domestic and commercial connections to the network. Demand from Industrial customers is anticipated to grow only slightly over the forecast period.

The total projected Tariff V gas demand is as follows:

	Domestic		Commercial		Industrial		Total	
Year	No. of Customers (June)	TJ	No. of Customers (June)	TJ	No. of Customers (June)	TJ	No. of Customers (June)	TJ
2003	438,194	24,006	11,917	5,380	548	1,575	450,659	30,972
2004	445,161	24,350	12,484	5,548	560	1,593	458,206	31,500
2005	452,110	24,641	13,051	5,694	572	1,604	465,734	31,949
2006	459,819	25,001	13,618	5,850	584	1,618	474,022	32,479
2007	468,018	25,384	14,185	6,006	596	1,632	482,800	33,032

Table 41 Aggregate Demand for Tariff V Customers

Year	Domestic	Commercial	Industrial	All
2003	1.51%	2.97%	0.85%	1.73%
2004	1.43%	3.12%	1.09%	1.71%
2005	1.20%	2.64%	0.71%	1.42%
2006	1.46%	2.74%	0.88%	1.66%
2007	1.53%	2.66%	0.86%	1.70%

Table 42 Change in Tariff V Demand

These volume forecasts are based on the following input assumptions:

Year	Gross No. of New Connections	No of Meter removals	EDD Assumption	Growth per connection %
2003	8,783	1,418	1439.5	*-0.2*
2004	7,987	1,418	1434	*-0.2*
2005	8,746	1,418	1428.5	*-0.2*
2006	9,508	1,418	1423	*-0.2*
2007	9,728	1,418	1417.5	*-0.2*

Table 43 Key Factors Influencing Demand by Domestic Customers

Year	Gross No. of New Connections		No of Meter removals		Growth per connection		Economic Growth
	Comm	Ind	Comm	Ind	Comm	Ind	
2003	684	23	116	11	*0*	*0*	*2.5*
2004	683	23	116	11	*0*	*0*	*3.2*
2005	683	23	116	11	*0*	*0*	*3*
2006	683	23	116	11	*0*	*0*	*3*
2007	683	23	116	11	*0*	*0*	*2.8*

Table 44 Key Factors Influencing Demand by Commercial and Industrial Customers

Tariff D

Demand from Tariff D Customers in Victoria is anticipated to grow by an average of 3.0% over the forecast period, reflecting a number of factors including growth from food industry customers, notably in northern Victoria. Customer numbers are anticipated to continue to grow slowly. The forecast takes into account known expansion and contraction plans, and assumes a number of ‘surprise’ new loads over the period.

Year	No. of Customers	Sum of MHQ	% Change in MHQ
2003	216	7204	3.87%
2004	225	7400	2.72%
2005	234	7588	2.54%
2006	243	7790	2.66%
2007	252	7965	2.25%

Table 45: Total Demand by Tariff D Customers

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