2005/06 ESCoSA

GAS DISTRIBUTION PRICE REVIEW

OF

THE ENVESTRA ACCESS ARRANGEMENT

A response to the

Envestra Access Arrangement Application

by

Energy Consumers Coalition of South Australia

November 2005

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Executive summary

Envestra is seeking very substantial increases in gas transport tariffs over the next five years, rising by some 40% over the period in nominal terms. In stark contrast, electricity transportation charges in both South Australia[1] and Victoria[2] have been reduced (4% and 10% respectively) whilst gas transportation charges in NSW[3] have been reduced by 12% for industrial users and 5% for household users.

The proposed Envestra tariff increases are attributed to:-

1. Increased operating expenses
2. Increased capital expenditure
3. Reduction in gas usage
4. Presumption that its previous actual capital expenditure program should be automatically rolled into the Regulatory Asset Base
5. An excessive WACC

ECCSA, however, strongly considers that Envestra has failed to justify what are clearly ambit claims:-

- Envestra's past allowed capex has not achieved the outcomes determined by SAIPAR let alone Envestra's own expectations.

- Concern that allowed capex has not been demonstrated to be prudent and efficient.

- Envestra's claims for substantially increased capex sit uneasily with its own forecast of a reduction in gas transportation and a fall in demand by large and small customers.

- Envestra's claims for substantially increased capex have not been sufficiently justified and many items claimed are either refuted or queried.

- Envestra's demand growth forecasts do not appear to be based on sound methodology and do not appear to be estimates arrived at on a reasonable basis.

- Envestra's WACC claims are excessive and, based on benchmarking data, its real pretax WACC is some 3 – 5 percentage points above where "real" pretax market returns have been for the past decade.

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[1] ESCOSA Final Decision on ETSA Utilities price cap, 2005
[2] ESCOV Final Decision on Electricity Distribution Price Review 2005
[3] IPART, Revised Access Arrangement for AGL Gas Networks, Report on Further Final Decision. June 2005

ECCSA made representations to SAIPAR after the issue of its Final Decision regarding the costs allocation methodology between demand suers and the residential/commercial users. Envestra has not included for any changes in its current application to the demonstrably flawed approach and costings used in the last application. The outcomes of the approach used then and proposed to continue is clearly perverse with the Envestra costs in the Southern gas zone being considered as making a contribution to the loss of major industrial demands of gas from Mobil, Ion, Mitsubishi and the transfer of other loads to lower cost zones. ECCSA has provided extensive detail as to the flaws in the Envestra approach, and strongly recommends ESCoSA investigate this issue in detail.

Despite proposing very substantial increases in tariffs, Envestra has failed to provide the relevant quantities data to justify the significant assumptions and statements made in support. Some of these assumptions are heroic and are not soundly-based.

Deficiencies in data disclosures and the lack of transparency in Envestra's proposed access arrangement are a feature of its application and do not satisfy many code provisions, including sections 2.6, 2.7, 3.1 and 3.20. The previous regulator, SAIPAR, had expressed its concerns with information disclosures at the last access review and had required Envestra to comply with the relevant information disclosures provisions in its Final Determination. In particular, SAIPAR stated:-

> "There have also been general difficulties in obtaining information required to finalise some aspects of the Final Decision. This has contributed to delays in issuing the Final Decision. Envestra's information systems may well not have been geared to produce some of the information required for an Access Arrangement. However, Envestra will be required to amend and update the Access Arrangement Information to comply with the requirements of sections 2.6 and 2.7 of the Code. Some of the information now required to be gathered could be useful for Envestra's own future commercial deliberations."[4]

Deficiencies in information systems cannot now be accepted in the current review and Envestra must be required to comply with the information disclosure provisions of the Code.

[4] SAIPAR FD page 7

1 Overview of the Proposed Envestra Access Arrangement

The Key Elements Of The Application That Will Have A Cost Impact On Gas Users

The Energy Consumers Coalition of South Australia, (ECCSA) is concerned with Envestra's ambit claims for very substantial tariff increases. In this section, the key elements of Envestra's ambit claims are highlighted.

Envestra is seeking an average initial increase in all **tariffs** by some 8.5% and is proposing to dispense with the northwest tariff zone for large consumers of gas. Envestra advises that elimination of this northwest tariff zone will only affect one company, **although the impact on that company will be significant**.

Envestra proposes that tariffs will change over time in accordance with the formula based on the CPI – X approach. It is proposing that the X factor should be a negative 0.059, implicitly resulting in a "real" increase in tariffs of about 6% in each subsequent year over the five year period of the access arrangement. The import of this is that tariffs in the last year of the arrangement will be nearly **40% higher** in nominal terms than they are currently, bearing in mind that volumes of gas transported are not forecast to rise.

For residential consumers the distribution portion of gas tariffs is about 50% for the cost of gas delivered. The tariff increases proposed by Envestra alone will increase domestic tariffs by more than 20% over the five years, well above the forecast rate of inflation. Increased retail and gas purchase costs will further add to this figure.

Envestra considers that the current allowance for **depreciation** is too low and that an increased depreciation allowance should be permitted, thereby requiring consumers to increase their contribution to Envestra's depreciation **by over 50%.**

In addition, to accommodate the proposed increase of **140%** in **capex** in order to upgrade the network and "to do a better job" Envestra considers that **opex** should increase by about **30%.**

These increases are sought even though Envestra advises that its customer numbers have stayed at much the same level as in the previous access arrangement period.

Envestra had received a lump sum amount of $54.6m from the SA government as reimbursement for the costs it would incur from implementation of **Full Retail Contestability** (FRC). Envestra has excluded this amount from the Regulatory Asset Base (RAB) but has not disclosed where this contribution has been spent, nor has Envestra disclosed the outcomes from that subsidy.

Despite this capital injection from the government Envestra is seeking additional funds to upgrade its **IT system** to accommodate FRC.

2 Outcomes of the Current Access Arrangement

General Comments

The Gas Access Code requires that investments in gas pipelines be both prudent and efficient if they are to be rolled into the capital base at the start of the new regulatory period. Sections 8.8 and 8.9 of the Code set out the principles for establishing the capital base at the commencement of the new access arrangement period.

Implicit in Envestra's application is that through the capex invested over the year 2001/02 to 2005/06 it has:-

- Maintained past service levels
- Connected some 23,000 new small customers (or a 7% increase)
- Increased gas supply to small customers by some 329 TJ pa (or a 3% increase)

This would mean that Envestra invested an average of $21m pa in new facilities or incurred new capex at a cost of $4600 per new customer. The capex was to achieve a reduction in system use of gas (SUG) but in fact SUG is forecast now to be greater than that experienced in 98/99 levels.

There is an implicit assumption that either the new small customers use less gas than other small customers, or that across all small customers, there has been a small reduction in the demand for gas.

However, missing from the access arrangement information is the change in large customer numbers and the large customer demand. Envestra also does not provide a breakdown of the impact of changes in the demand haulage service, which contributes some 10%[5] to the revenue stream.

Accordingly, ECCSA considers that Envestra has not complied with sections 2.6, 2.7 and 8 of the code.

[5] SAIPAR Final Decision. Table 8.3.2.2 Revised Revenue Requirement 1999/2000 Haulage Category Revenue Requirement Shows:

Domestic Haulage Service	$ 88.73m
Commercial Haulage Service	$ 15.5m
Demand Haulage Services	$ 11.9m
Total	$116 m

Investment in capex has a four fold application –

- to provide services to more consumers (eg compare capex to increase in consumers)
- to provide more gas throughput (eg compare capex to increased volume of gas sold)
- to improve the quality of the service (eg compare capex to reduction in SUG), and
- to reduce opex (see later comments about the interaction of increased capex and the effect on efficiency and a reduction in opex).

Envestra has advised that it has an overrun on allowed capex. This result presents specific challenges as the regulator has to assess the prudency and efficiency not only of the allowed amount but also of the overrun.

Investment must be prudent and efficient. The average cost to supply the existing 363,600 consumers averages some $2200/customer.

Comparatively,

- the new customers have been acquired at some $4600/customer of capex. This means that Envestra is a high cost provider of new connections a view is supported by the information provided in the WorleyParsons[6] (WP) report attached to the access arrangement[7]. While it is accepted that not all capex has been devoted to new customers, Envestra has made no attempt to demonstrate that the past capex has been prudent <u>and</u> efficient.

- the capex allowance of some $100m over the five years was in part to reduce the loss of gas (SUG) from the network, yet it has been demonstrated that gas losses have actually increased. This issue is further discussed below in section 2.1.

Compared to capex the need for opex is:-

- to mange the network,
- carry out routine servicing,
- provide “break down” maintenance
- provide for SUG, and
- provide support for the physical extension of the network.

[6] Review of Gas Access Arrangement for South Australia WorleyParsons 28 Sep 05
[7] WP report tables 8-11 to 8-15

Accordingly, there is an expectation that:-

- opex would reduce with an increase in capex (but the opex claim has actually increased)
- at best opex would have to increase marginally with growth (actual opex growth has outstripped the modest 7% increase in numbers), and
- there would be a reduction in UAFG (which has not occurred).

Thus, in headline terms the outcomes expected by SAIPAR (in increased efficiency and thereby a reduction in unit costs) from the opex and capex investment allowances made in the last review have achieved little improvement.

2.1 System Use of Gas (SUG or UAFG)

Envestra was expected to reduce its UAFG over the previous access arrangement period but has it? In its first application it suggested that it would reduce SUG as follows:-

Year	98/99	99/00	00/01	01/02	02/03	03/04
SUG (TJ)	1599	1498	1377	1287	1271	1271

The SAIPAR Final decision clause 7.5.3, stated that these SUG forecasts were to be reduced by 6% per annum of cost over the access arrangement period, with a total of 30% over the 5 year period, ie to a level of no more than 1230 TJ pa.

Envestra now advises that the new targets in the new access arrangement period are:-

Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11
UAFG (TJ)	1606	1606	1606	1591	1575	1560	1545

This clearly shows that Envestra has not achieved its own target of 1271 TJ in the previous access arrangement period, let alone the SAIPAR targets. In the absence of relevant information provided by Envestra in its current application, it would appear that a significant amount of past capex has not been prudent or efficient, as a key element of the previous AA has **not** been achieved.

It would appear that as Envestra has failed to reduce the amount of SUG, it now proposes that this matter is no longer its responsibility but would now be sourced to retailers, who will treat it as a pass-through to consumers[8].

The Issues before ESCOSA are clear:-

- Envestra's past allowed capex has not achieved the outcomes determined by SAIPAR (let alone Envestra's own expectations)

- Envestra's overrun on allowed capex has not been demonstrated to be prudent or efficient.

- Envestra's existing customer base must not be required to cross-subsidise Envestra's new customers

- Envestra must not be rewarded for its inefficiencies.

Unless these issues are satisfactorily resolved, ECCSA considers that the following provisions of the Code have not been complied: sections 2.6, 2.7 and 8.

2.2 Comparisons between Envestra requests and SAIPAR allowances

Envestra implies throughout its application that the SAIPAR allowances were inadequate for the purpose of operating the gas distribution network, as Envestra points to revenue variance, opex variance, capex variance, small customer gas usage and small customer number growth[9], and that because of this SAIPAR had little understanding of the drivers behind a gas distribution network.

Envestra in fact did provide SAIPAR with "forecasted" Load and Customer estimates for the 2000/01 period (which does not include "farm tap loads") as indicated in table 2.1.2[10]. below:

Table 2.1.2 Forecast Load and Customer Numbers

Customer Class	*Customer Numbers*	*Load TJ*
Domestic	329,455	7,926
Commercial	8,860	3,030
Demand	142	17,129

Comparing these forecasts directly with the SAIPAR assumed levels of gas consumption, as shown in table 8.6.3.2 of the Final Decision, indicates that

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[8] Envestra AA section 9.6
[9] See Envestra AAI tables 1, 2, 3, 4, 5
[10] ibid

SAIPAR allowed a **greater** consumption of gas in 2001/02 than initially forecast by Envestra, but only by a total margin of 1.3%.

Table 8.6.3.2 Final Decision Load Forecasts

Customer Category	2001/02	2002/03	2003/04	2004/05	2005/06
Domestic (TJ's)	8,170	8,268	8,368	8,462	8,558
Commercial (TJ's)	3,056	3,082	3,108	3,134	3,161
Demand (TJ's)	17,223	17,316	17,413	17,509	17,509
TOTAL (TJ's)	28,448	28,666	28,889	29,106	29,228

Note: Numbers have been rounded to the nearest 1.0 TJ's. Farm Taps excluded.

Against this disparity in volume forecasts, Envestra revenue increased at the rate of some 1.8% pa[11], whereas SAIPAR forecast a rate of increase in small consumer gas use of only 0.9%[12]. Thus there is inconsistency between the presentations made by Envestra in its AAI.

It must be clear that the data provided by Envestra is not complete and so prevents an accurate view of the real drivers of demand in the previous period. These deficiencies need to be clarified and Envestra must expand its information disclosure to show all forecasts (domestic, commercial and demand) and the revenues raised from each sector.

Without such information, it is also not possible to test the veracity of Envestra's forecasts in the new access arrangements period.

In its new forecasts Envestra opines that gas usage by small consumers will **fall** by 0.3% pa despite a **rise** in small consumer numbers of 2% pa.

This is inconsistent with its recorded performance of an increase in demand of 0.26% pa with an increase of small consumer numbers of 1.8%. Thus for a penetration rate in small consumer numbers which is shown to be increasing historically, Envestra is forecasting an overall **reduction** in consumption. On the basis of historical figures, an expectation is with the increased penetration that consumption would increase by at least 0.3% pa, rather than the fall forecast by Envestra.

Envestra states that the MDQ paid for by large consumers will fall immediately in 06/07 by over 4% and then remain constant for the new period. This implies that industrial growth in SA will fall by 4% next year and not change over the coming five years. SAIPAR in its FD forecast industrial demand growth of 0.05% pa. However, Envestra does not provide any indication of what large industrial demand growth occurred during the current period, other than to state that the closure of the Mobil refinery caused a reduction in demand. It is unacceptable for Envestra to baldly state that MDQ will fall and then remain constant. It must provide historical data and back that with hard data supporting its forecast.

[11] From Envestra AAI table 1
[12] ibid table 2

ECCSA considers that Envestra's demand forecasts for large customers must be based on a sound methodology and must represent best estimates arrived at on a reasonable basis, as required by Section 8.2 (e) of the Code. As Envestra has not provided evidence of changes to contracting by large customers, the forecasts it has provided could be based on arbitrary assumptions, which is not a reasonable basis. Envestra's forecasts must be based on these customers

With the high price for gas transport in the Adelaide Southern Zone, it is not unexpected that growth in this part of the network is shown to be negative, and the subsequent closure of the Mitsubishi Engine plant at Lonsdale attests to this.

3 OPEX and CAPEX

Envestra and OEAM

It is important to clarify the relationship between Envestra and OEAM, its contracted operator.

OEAM is a subsidiary of Origin Energy which was the only shareholder when it created a contractual relationship between OEAM and Envestra. Origin subsequently “floated” some 80% of Envestra while maintaining this contractual relationship for operating the Envestra assets. Thus there is no clear way that stakeholders can verify that the contract for operating the Envestra assets has been established either “at arm’s length” or in a competitive manner.

The WP report addresses this apparent lack of a competitively established relationship by attempting to benchmark the management fees[13]. Further, the WP report has confirmed that OEAM receives 1/3rd of any savings OEAM generates in opex and capex.

Whilst the principle of providing incentives in return for savings achieved is agreed to, the assessment of any allowance for third party management of opex and capex should not rest purely on management fees and incentives. For instance, there is no clear demonstration that the OEAM contract is competitive in an open environment (compared to Envestra doing the work itself or another party carrying out the tasks). The OEAM management fee plus saving shares plus directly incurred costs must be demonstrated to be robust, and at ‘arms-length’ transactions.

Further the allowances for Envestra of opex and capex should only be at a level an efficient provider would require and not be at a level stated contract by the asset owner.

It is also incumbent on the asset owner to ensure that its contracted party is aware that the assets are regulated and that the contracted party must provide all of the information the regulator requires in order to assess the reasonableness or otherwise of the allowance the regulator deems appropriate to be included in the regulated revenue.

The inter-relationship between capex and opex

Although capex and opex are usually independently assessed there is a strong inter-relationship between the two issues. In fact, the benefit of increased capex for most aspects should result in decreasing opex. In the previous review by SAIPAR, the business was granted a massive increase in capex, and a modest change to opex.

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[13] WP report section 5.1

The reason for an upward spiral of opex levels in some decisions of regulators results from the misguided but widely promulgated view by electricity transport businesses that opex *rises as a consequence of increasing capital base.* This is totally incorrect. Based on the experience of companies operating in a competitive market environment, there are three reasons why the capital base increases over time:-

1. By replacement of existing depreciated assets with replacement assets (commonly referred to as refurbishment)
2. By replacement of existing assets with larger assets to reflect an increase in demand (commonly referred to as augmentation assets)
3. By extending the reach of the existing assets (commonly referred to as expansion assets)

When examining the opex implications of each of these reasons for the asset base to increase in size, the justification of increased opex can be put into proper context.

<u>(i) Opex from refurbishment</u>

There is no doubt that refurbishment increases the value of the asset base. Replacement of a depreciated asset with new assets will axiomatically result in an asset base increase.

However, the business case for justification of refurbishment is usually presented as a *reduction* in opex. In competitive enterprise such a business case is made on the basis that recovery of the capital will result from the saving in opex, often with a payback duration measured in months, and commonly within two years. If this business case cannot be made the continuing opex related to keeping the asset in working order is tolerated.

Thus, capex related to refurbishment should result in a significant reduction of opex.

<u>(ii) Opex from augmentation</u>

There is no doubt that the replacement of a capital item with a larger unit to accommodate an increase in output will increase the asset base. The replaced item will either be relocated to another point in the business replacing another similar item, held in stock for future use, be sold, or scrapped.

When examining the opex implications of an augmentation, the new item will almost invariably be newer than the replaced item if the asset base is to increase. The issue then is: does the opex requirement for an item increased in size (eg a transformer increased from 10 MVA to one of 25

MVA, or a power line increased in diameter for higher current carrying capacity) require a proportionate increase in opex related to the value of the larger item? The answer to this question is in most cases “only marginally at most”.

It costs the same to monitor a small transformer as it does a larger one, it may take a little longer to replace the oil, but a larger diameter cable or aerial requires the same amount of attendance as a smaller diameter cable or aerial. Newer equipment should require less maintenance than older plant.

In sum total, opex from augmentation should result in a modest reduction as a result of an augmentation of assets.

(iii) Opex from expansion

Expansion of the network results from increasing the reach of the network. This could come from increasing the number of equipment items at an existing facility or from providing a service to a new area not previously serviced. Expansion increases the asset base.

Opex from expansion will increase with the asset base, although not necessarily proportionately. There are two fundamental expansion options – embedded in the existing network and external to the existing network.

Embedded expansion, whilst requiring additional attendance, allows the opex increase to be marginal. An example of this is where a third transformer is added to an existing facility. In this case the time for attendance is a marginal increase on the cost to service the existing two plant items. Another example is where a new power line is erected adjacent to an existing power line, or even off the existing towers. In this case the opex cost should be measured as a marginal increase in cost and not a proportionate increase.

External expansion is where the new items are remote to the existing network and the opex costs will be proportionate to the increase in asset base.

(iv) The opex implications from this analysis.

It is the mix of capex (refurbishment, augmentation, embedded expansion and external expansion that will determine the extent of opex reduction or small opex increase. The greater the refurbishment the greater the opex reduction should be as a proportion of the RAB.

Opex

Envestra had sought a total of $41.1m[14] for opex in year 05/06 and SAIPAR awarded it $40.2m[15], which included a lesser amount of SUG of some $0.3m. Effectively SAIPAR awarded Envestra what it sought for opex. Any suggestion that SAIPAR was incorrect in the allowance it granted is therefore misleading. The fact that Envestra expects to over spend on opex in year 05/06 by some 6% over its own forecast cannot be attributed to an error by SAIPAR, as implied in the Envestra AA Information.

What is even more misleading is that while Envestra implies that its claim for non-capital costs in 06/07 of $49.1m is 17% above the current SAIPAR approved allowance for 05/06, the Envestra opex claim excludes an allowance for SUG, valued at some $6.8m[16]

> "Envestra has not included any costs for UAFG in its Access Arrangement, in anticipation that ESCoSA will accept this new approach".[17]

Thus the Envestra claim for opex for 06/07 is in fact a significantly larger increase of some 33% over the SAIPAR assessed non-capital costs for 05/06.

The report from WorleyParsons (WP) provides quite clear benchmarking data which establishes that the current levels of opex are in the correct ranges or even on the high side of average[18].

Therefore, increasing opex substantially from current levels is clearly not consistent with the external benchmarking results suggested by WP. It should be noted that these benchmarks included the cost of SUG which Envestra has now excluded from its opex forecasts.

In addition to overall benchmarking, WP provides Envestra with a view on the additional opex over that used in the current period and needed in the next period. The following listing is not complete as the SUG allowance (which constitutes over 16% of current allowed opex) must be accounted for first.

1. The opex claim excludes SUG and therefore the totals and breakdowns provided by Envestra and WP are incomplete and could mislead. If Envestra intends to exclude SUG from its opex claim then all breakdown elements must be provided which exclude the SUG allowances (to

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[14] SAIPAR FD table 7.2.1
[15] Ibid table 7.9.1
[16] This is based on the $5.1m SAIPAR allowed for 1271 TJ of SUG. Envestra states it needs 1606 TJ for year 06/07, so the $6.8m allows for inflation and the increased quantity of SUG
[17] Envestra AA section 9.6, last paragraph
[18] WP report table 8.5

ensure consistency) so that a careful comparison can be made of forecast opex over past opex.

2. Self insurance. Whilst the concept of self insurance has been generally accepted by regulators, by adding in an allowance implies that past opex excluded an allowance for insurance. This self insurance allowance must be netted off against premiums previously paid.

3. IT increases by over 7% average in real terms, but there is little justification provided.

4. HR costs increase by 4% average real but this is surprisingly deemed immaterial by WP.

5. A&F costs increase by nearly 6% average real and supposedly are caused by the need for better financial reporting. The legitimate benchmarked levels should only be accepted.

6. Network services increase by 8% average real due to FRC workload. But the government has already paid for this by way of a lump sum contribution.

7. Envestra claims $5m pa for market development, yet this expenditure is not related to the expected benefits, nor is there any explanation as to what this market development is to be used for. In the case of ETSA Utilities it was found that much of its market development was for corporate image enhancement. Envestra must provide better particulars of where expenditure is actually directed to and the expected outcomes.

8. FRC is a new item valued at over $6m pa. Yet the government has already provided a lump sum for this purpose.

9. An allowance of $1m pa is sought for “an ageing workforce” yet competitive industries face this same problem and can accommodate the outcomes (without increasing prices) through productivity improvements (especially including matured and experienced workers). However Envestra states that 75% of the costs are for **additional** field workers and engineers, with the balance being for loss of productivity and increased health costs. Why are these additional costs necessary?

10. Envestra claims an average of $1.3m to address changes to regulatory requirements, governance and services. Of this increase in cost:-

    a. 37% is for the increased costs of servicing new customers, yet Envestra has already accounted for the costs of new customers in its base costs
    b. !0% is to accommodate new Australian standards but fails to state which ones

c. 20% is for increased regulatory compliance costs but does not provide any substantiation as to what has changed to require this increase (note that SAIPAR had previously determined an opex allowance consistent with the requirement for improvements in Envestra's information systems).
d. 20% is for increased service response but as noted above Envestra states that it intends to maintain the same service levels.

Envestra needs to more fully explain whether these changes are real, why they might result in increased costs and to substantiate the increases.

11. Envestra proposes to increase its focus on risk management by the addition of nearly $1m pa but provides no expectation of the cost savings that will result, as the opex and capex costs are proposed to continue to rise. There must be an efficiency dividend to offset this increase in costs.

12. There is an increased amount in real terms of $0.6m pa due to "increased cost pressures" to pay for "contractor price catch up", relocation of a facility and an expectation of an increase in the SGL. These are not legitimate reasons for an increase in the opex claim.

13. There is a claim of an average $1m pa for remediation of the Osborne site (which was allowed for by SAIPAR) and continuation of clean up at other sites. Envestra already has an allowance in its opex for remediation, and has not explained why this is insufficient for the works proposed.

14. Envestra requests an additional allowance of $350k pa to provide for additional office equipment to match the additional staff it intends to recruit. As the need for additional staff has not been proven justified then neither is this item justifiable.

15. Efficiency gains. Envestra suggests that it should be able to achieve efficiency gains of 1.24% pa over the five year period. Except in Victoria, efficiency gains in other jurisdictions are higher than this amount and compare badly with the efficiency gains SAIPAR imposed of 4%

Overall, Envestra has not provided sufficient evidence to support its increase in the base allowance for opex, nor has it provided sufficient substantiation for the 10% increase in opex to accommodate "material changes".

Capex

There should be no limit to the amount of efficient capex Envestra seeks to invest. However, there must be a limit on the capex that Envestra wants to invest and for which it seeks to roll into the Asset Base with consumers paying a return.

The Gas Code requires investment (capex) to be efficient and prudent. The onus is on Envestra to demonstrate that the capex program it proposes is both efficient and prudent. Envestra proposes a capex program which is more than twice the current capex program, but other than to advise what is proposed to be spent (in two categories – “stay in business” and “growth”) there is no demonstration that this capex is prudent and efficient and that WorleyParsons says it is so.

The WP report advises that it has reviewed the program in a “bottom up” fashion and a “top down” approach and considers the program meets the requirement of prudency and efficiency. WP goes on to say that each of the projects they reviewed met an IRR target, but then failed to identify what this benchmark was. IRR can be negative but for most enterprises the IRR benchmark needed for a capital works project to proceed is usually at least 15% and for certain types of projects may be as high as 30-40%. Unless the IRR benchmark is identified, then it cannot be assumed that the projects reviewed by WP are prudent or efficient. ECCSA points to the strong doubts about the efficiency of past capex in the previous access arrangement period.

WP provides information (section 9 of the report) that the “stay in business” capex requirement for the new period is about $17m pa, up from the previous period by a factor of more than two. The main costs are for:-

- a SCADA system costing over $1m pa, some six times the current capex allowance
- new regulators costing $1m pa,
- additional domestic meter changes, up from $1m pa to over $3m pa
- additional I&C meter changes, up from $300k pa to $1.1m pa
- new odorising, corrosion protection, and non FRC IT projects
- a doubling of the rate of mains renewal to $8.5m pa up from $4m pa

Unfortunately neither Envestra nor WP provide details of any benefits (to consumers) resulting from the massive increase in the “stay in business” capex. Until this is done there can be no assessment of the validity of this element of the capex program.

WP’s report provides a break down of the growth element of the capex program. This shows a 30% increase from the current $14m pa to over $18m pa. This is consistent with the forecast of an increase in numbers of customers (currently 1% pa but forecast to be 2% pa by Envestra).

However, this is at odds with the forecast **reduction** in gas transported by ½% pa. There is no financial assessment of whether the increase in capex allowance is offset by the reduced revenue which will come from the forecast reduction in volumes sold. Envestra must prove that the return from the capital expenditure really does more than offset the costs involved.

If the cost of connecting new customers is sub-optimal then an approach similar to that in Victoria should be examined whereby the government for social policy reasons finances suboptimal augmentations to the point where they become optimal. Consumers should not be required to provide the subsidy.

Envestra (and WP) have not provided sufficient justification for substantially increased capex. On the contrary, claims for increased capex sit uneasily with Envestra's own forecast of a reduction in gas transportation and of a fall in demand by large and small consumers.

Benchmarking

The WP report provides clear support that the current cost structure (capex and opex allowances) for Envestra is in the ranges estimated by WP as being consistent with those of other gas network service providers**.** Further it states that Envestra has adequately performed the gas transport services required (although ECCSA points to the increasing loss of SUG as a reduction in service) within its current allowances. Within the current cost structure, Envestra advises it:-

- provides a high quality distribution service, with:
  - less than 15 complaints referred to Envestra by the Ombudsman in 2004/05 where there were issues with quality of service. Furthermore, the issues were generally of a minor nature (dirt left behind after a job, damaged storm water pipe, etc) and in many cases the customer had not first made contact with Envestra to rectify the issue; and
  - a very low number of gas outages – network operations resulted in only 5 incidents of unplanned loss of gas supply to consumers in 2004/05. The rapid response to network problems that is required for safety reasons also ensures that impacts on consumers are minimised.
- reports to the Regulator on service quality in relation to gas outages and promptness of customer connections on a quarterly basis, and other parameters (including customer complaints) on an annual basis to the Regulator and to the Office of the Technical Regulator;
- joined the ombudsman scheme operated by the Energy Industry Ombudsman of South Australia in November 2003. This additional and independent avenue for the lodgement of complaints by

consumers provides a valuable source of information concerning service levels and the performance of Envestra and energy retailers with respect to customer service;

- [assists] the Office of the Technical Regulator [to conduct] a thorough technical audit of Envestra's operations annually. Those audits confirm that the Network is operated and managed safely, appropriately and in accordance with relevant standards and good industry practice.[19]

Thus, it is clear that the current benchmark performance of Envestra over the past four years lies well within its current cost structure. On this basis there is little requirement for Envestra to claim additional opex and capex to continue its service provision into the next period.

[19] Envestra AA page 7

4 Weighted Average Cost of Capital

Envestra has assessed the WACC for energy distribution businesses based on the following key variables, about which it devotes considerable discussion.

- Nominal risk free rate has been suggested to fall between 5.43% and 6.25%
- Equity risk premium (MRP) has been suggested to fall between 6-7%.
- Equity beta has been suggested to fall between 1.0 and 1.1.
- Debt margin has been suggested to fall between 138 and 148 basis points
- "Taxation "franking" credits has been suggested to fall between 35% and zero

Using the ranges suggested, Envestra believes the "real pre-tax WACC" should lie between 6.70% and 9.99%, and opts for 7.30% as the most appropriate point.

Each of the suggested inputs lies between the "regulatory norm" and higher input values, suggesting that Envestra is entitled to a higher return than the regulatory norm.

The Gas Code is silent on what the inputs to the WACC development should be, other than to state:-

> ***General Principles***
>
> 8.1 A Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objectives:
> (b) replicating the outcome of a competitive market;
>
> ***Rate of Return***
> 8.30 The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the
> Reference Service is offered and any other risk associated with delivering the Reference Service).
>
> 8.31 By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing

> Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

The respected financial journalist Mr Alan Kohler stated in a recent article[20] that:-

> "….infrastructure companies get higher valuations than industrial companies … infrastructure is being valued by investors at more than your normal industrial assets for three reasons.
>
> - Depreciation charges are generally much higher than capital expenditure.
> - They can carry more debt, or at least everyone thinks they can.
> - The assets have longer lives and more stable cash flows than factories and shops.
>
> High depreciation charges and low capex on [sic] maintenance means that analysts can use EBITDA (earnings before interest tax depreciation and amortisation) in their models instead of the lower net profit …
>
> Investment life coupled with high gearing is the key. Most industrial companies are valued on five year projections of earnings with net present value calculated by discounting future profits by the weighted average cost of capital (WACC, the average debt and equity servicing cost). Equity costs more to service than debt – 11 per cent versus about 7. Industrial company discount rates are typically 10 per cent, infrastructure 8 or 9.
>
> On top of that, the analyst gets to have another 25 to 35 [yearly] columns in their spreadsheet, against which to apply this WACC because infrastructure means long life"

This assessment by Kohler presents a clear statement that industrial enterprises do and are expected to have a higher EBIT/assets than infrastructure businesses, yet the EBIT/assets resulting from regulatory reviews (ACCC has calculated an EBIT/assets for TransGrid and EnergyAustralia at over 11%) shows that regulated businesses actually are being granted a higher EBIT/assets than most businesses in the commercial world achieve as the following graph shows. This data is sourced form IBISWorld on the 150 companies which are in the S&P ASX 200 for a significant part of the last 15 years.

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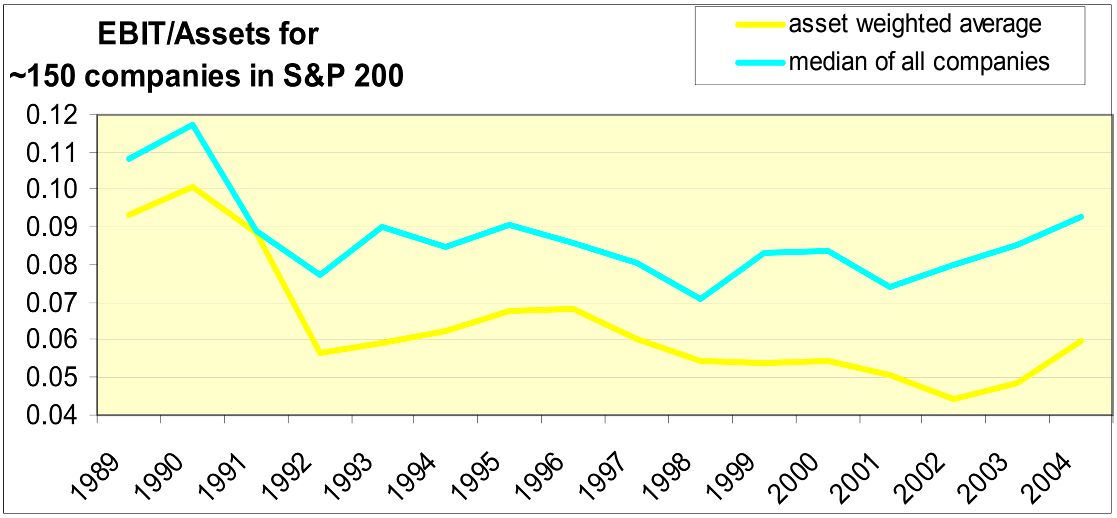
[20] The Age "For a genuine, low risk infrastructure go for a consistent hot air producer", 2 November 2005



Source: Data from IBISWorld, presentation by Excel

On this basis there is now little doubt that the WACC calculated by Australian regulators is not equitable when compared to returns earned by companies operating in a competitive environment. The two prime reasons for this are that regulators are granting an equity risk premium and equity beta consistent with those extant in the competitive environment at this time.

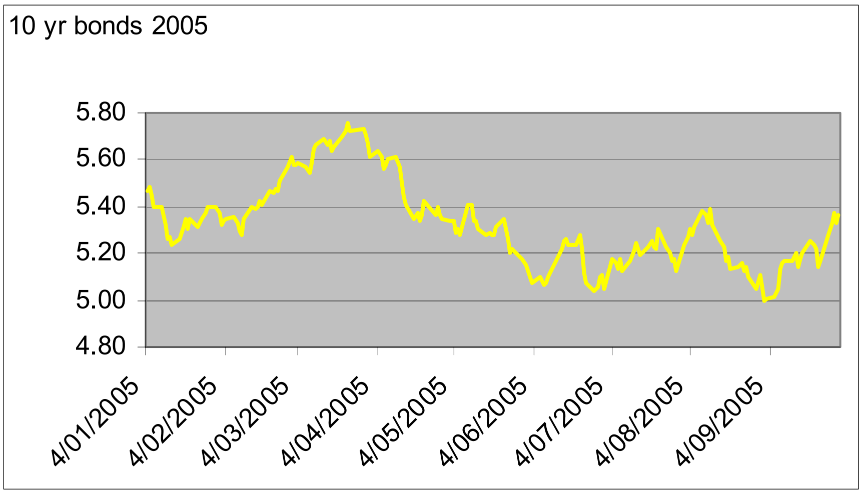
Elements of the WACC calculation

In addition to the MRP and equity beta discussed below, Envestra has placed a value on franking credits, nominal risk free rate, and debt margin. In each of these inputs Envestra fails to provide sound reasons for the determination of these factors.

- Nominal risk free rate

  Whilst it is now accepted that the risk free rate should be based on the 10 year bond rate, particularly as the market risk premium is also based on this benchmark. For Envestra to state that the Nominal risk free rate should lie between 5.43% and 6.25% belies the actuality, as the following graph shows. Since the beginning of 2005 the 10 year bond rate has remained below 5.8% tracking as low as 5%.

  Thus for a forward looking assessment of the WACC calculation, only a recent value for risk free rate should be used. There is some debate as to the period over which a value of the risk free rate should be calculated for Envestra to assess the risk free rate as high as 6.25% either implies a view that interest rates will climb sharply, or that Envestra is wrong. The fact that the market has assessed that government borrowings over a 10 year period from now should be more than the current value of 5.40% is patently absurd.



Source: Reserve Bank of Australia website

ESCoSA in the recent decision on ETSA Utilities was required to use the five year rolling average of 10 year government bonds to set the risk free rate. The Gas Code is not as specific, and suggests that a current forward looking WACC should be developed. This would therefore suggest that the risk free rate be based on the latest 10 year bond rates prior to setting the WACC. This is what the ESCoV did in its last decision.

- Franking credits

In the CAPM, the value of franking credits is included by the use of the "gamma" value but so far no one has been able to calculate the benefit of franking credits with any certainty. Gamma has been assumed to be as high as 1.0 which assumes that every one is able to benefit, to as low as zero which assumes no one benefits from franking credits. Envestra has assumed that gamma should lie between 0.35 and zero, and maybe this is a fair assessment for Envestra which is owned by an overseas corporation.

Because of the difficulty of actually identifying the value for gamma, regulators have assumed that the "notional" monopoly service provider is able to benefit to the extent of gamma being 0.5. This approach recognises that some service providers are owned offshore, and others wholly owned within Australia and many shades between.

- Debt margin

The margin a borrower pays above the nominal risk free rate is also an aspect of the CAPM which is vigorously debated. Envestra suggests that the debt margin should be between 138 and 148 basis points, but the data provided by Envestra could be construed as biased, seeking to maximise the debt margin.

> The two most recent decisions (that of ESCoSA for ETSA Utilities and ESCoV for the EDPR) suggest that debt margin is 1.64 (ESCoSA) whereas the ESCoV view is that it is 1.425. On this comparison the debt premium suggested by Envestra could be seen as reasonable.

In addition other elements associated with the return on investment need to be considered, either within the WACC or in opex. These are:-

- Equity raising costs
- Debt raising costs

These two costs are real but need to be assed with care that they have not been included by default in part of another calculation, such as the debt margin or in opex.

Equity raising costs should only apply to the raising of the equity element of capex approved to be rolled into the RAB. This is the only additional equity required as the original equity has been raised earlier and need not be raised again.

A financially wise company will have a range of debt instruments – some long dated (perhaps as long as 10 years but usually shorter than this) and some short dated (measured in months rather than years). The purpose of having such a debt spread is to minimise the cost of debt overall. Because the regulator should not attempt to second guess what the regulated company might do, it approaches the issue of debt raising for the notional regulated business. On this basis the regulator should only allow one debt raising per regulatory period, with these costs accepted as legitimate.

Envestra does not clearly identify where these debt raising costs and equity costs for capex have been included. The key issue is that they should not be permitted to be double countered.

Equity Risk Premium (MRP)

There is little doubt that the current value for MRP is less than 6%, yet the ESCoSA in its recent decision on ETSA has elected to maintain the value of 6% regardless of the future implications for the DBs and for consumers. In its paper on MRP by SACES it states that

> "The author's view is that the assumption that the mean 1-year excess return has been stable over the last 122 years is very tenuous. This tends to rule against the very long term average as an estimator. Now that high precision estimates are available for the past 30 years, it seems reasonable to put more weight on the past 20 years. When allowance is made for identifiable biases in excess returns as a measure of the MRP

> over the last 30 years, the central estimate for the MRP lies in the 4½ to 5 per cent range."[21]

The use of such an MRP in today's economic climate would bring considerable relief to consumers and would allow the regulator of the future some flexibility to increase the MRP when current market conditions would suggest that an increase is necessary to allow the regulated enterprise to access funds for needed capex in the future.

Overseas

Work by Ofgem in the UK clearly indicates that its assessment of the market risk premium is lower than 6% used by Australian regulators, and that it lies in the range 3-4%. Australian regulators have averred that the work by Ofgem is not applicable to the Australian environment as the market conditions are different, with the UK more attuned to Europe and the US equity markets, whereas Australia is remote from all of these markets and has its own but higher ERP. Ofgem makes the point that companies are exposed to the global markets and therefore there is little likelihood of ERP variation between nations.

Even if there is variation it is appropriate to examine the extent of such variation. In 2003 officers of the RBA[22] attempted to identify why there is a variation between the share prices of the same company and listed in different countries – dual listed companies (DLCs). There is a later report by ABN Amro[23] which also attempts to explain why there is this divergence. That there has been an attempt to identify why there is a divergence tends to fly in the face of the Australian regulators accepting blindly that there will inevitably be a difference.

Whilst the reports do identify that there are differences between share prices in the different countries, the magnitude of these share price differences in the dual listed companies does not equate to the premium in ERP between the two countries (UK and Australia) that regulators have effectively implied, and the difference in the "risk free rate" examined in the ECCSA report section 2.2 and attached to this submission might well provide an answer for the bulk of any variation.

The difference of share price of the same companies between the two countries tends to show that the Australian prices are higher, albeit only marginally.

> "The average premium for the locally listed BHP scrip over its British counterpart over the past three years has been 4.9% according to ABN

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21 The Market Risk Premium for Australian Regulatory Decisions, SA Centre for Economic Studies April 2005 page (iii)

22 "The characteristics and trading behaviour of dual-listed companies" by Jaideep Bedi, Anthony Richards and Paul Tennant Research discussion paper 2003-06 published June 2003 by the International Department Reserve Bank of Australia

23 Referred to in an article "Different countries, same company: explaining the price divergence in dual-listed companies" by Stephen Bartholomeusz The Age 29 June 2005

> Amro, with Rio [Tinto] experiencing a premium of 3.2% over the past three years and Brambles a premium of 9%"[24].

The article goes on to opine that the differences might be caused by the

> "… broader outlook for the individual economies and currencies, and including issues like the weight of money flowing from our mandated superannuation system, our franking system …"[25]

That theses reports were based on the assumption that the DLCs would have the same price in different markets is a view that is counter to the regulatory assumption that there is inevitably a difference. The reports further identify that the measured differences between the two markets is not sufficient to support the premium that the regulators in Australia are applying, particularly when the difference in the risk free rate is identified.

Thus the work by Ofgem in the UK should be considered much more closely than awarding it the casual dismissal afforded to its assessment of MRP by Australian regulators.

Recent Australian research

There is little doubt that MRP is not a fixed amount and that it varies over time. Further depending on the method used to calculate it, differing estimates result. Because of these shortcomings regulators aver that it is necessary to infer a degree of estimation and averaging. As a result higher MRP figures of many years ago should be discounted and there should be a move to an MRP which is more in keeping with more recent estimates of its value.

Recently Capital Research (an organization associated with Prof RR Officer, developer of the CAPM) released a report that opines MRP should be some 4.5% stating that only more recent values of MRP should be used in preference to long term averages. Another independent assessment of MRP was made by SACES which demonstrated that the MRP should be between 4.5 and 5%.

The ESCoV states in its recent work that:-

> "One implication of the new material presented is that the Commission's previous view about the equity premium of 6 per cent may not be inconsistent with a more sophisticated interpretation of the long term historical evidence. The material confirms that the Commission's previous view may overstate the estimate that would be obtained from placing greater weight on the more recent market evidence."[26]

Bearing the advice that recent independent studies clearly show that the MRP at 6% is currently overstated, the ESCoV fell back on the fact that no other

[24] ibid
[25] ibid
[26] ESCoV draft decision page 304

regulator has moved from the level of 6% and therefore it felt that regulatory precedent overcomes recent independent advice, relying on the view that:-

> "… an appropriate value for the equity premium [of 6%], particularly in light of its concern to create a stable, predictable and replicable regulatory regime to the extent possible, and in light of the long term consequences of its decisions."[27]

This resort to follow the earlier decisions of other regulators (justifiable to an extent) despite hard evidence to the contrary delivers a self perpetuating result and the cycle cannot be broken until another regulator accepts the market evidence and elects to move in a direction which most regulators see has justification but none is prepared to be the first to move.

Regulators consistently refer to the need for a stable, predictable and replicable regulatory regime. However to provide a stable regime with regard to MRP is not possible. In fact the analysis carried by all independent bodies have identified that the MRP is volatile, both in the long term and in the shorter term. Therefore for a regulator to consider that a stable long term average should be used consistently is essentially flawed.

This then raises the intriguing issue that if the MRP is currently really below the benchmark of 6%, then it can just as easily exceed the 6% benchmark in the future as by using long term averages there must inevitably result at some point in the future in the regulated businesses being awarded an MRP which is too low for them to access adequate funds needed for the networks.

Whilst this issue has been raised by consumers before, regulators seem to have elected not to even respond to this concern or even consider such an issue at this stage, leaving the clear implication that this will become a problem for a future regulator.

This is totally unacceptable from a consumer viewpoint, as it will be the consumers that will bear the brunt of network service deficiencies if the regulator does not provide sufficient revenue to source funds for essential works.

The recent actions of regulators can only lead consumers to the view that regulators have been influenced by the recent hype and publicity[28] that unreasonably high levels of MRP (and therefore WACC) are needed to encourage the regulated businesses to invest in the networks. The fact is that such investment has proceeded at significant levels and that there is no indication in the energy markets that there has been any under investment

[27] Ibid ESCoV draft decision page 306

[28] A classic example of this hype was the decision of Prime Investments to refuse to carry out necessary augmentation at Dalrymple Bay Coal Terminal unless the QCA granted them and increase in equity beta leading to an increased WACC. This resulted in the Federal Government commissioning a report into infrastructure needed for export of Australia's goods.

caused by low returns. The under investment seen, particularly in Queensland and NSW, has been more the result of the governmental owners of the regulated businesses seeking additional extraordinary returns well above that considered reasonable in privately owned businesses.

Equity Beta

In recent decisions relating to electricity distribution assets carried out over the past 12 months by QCA, IPART and ESCoSA, all have decided that the equity beta for electricity distribution should be 0.9. In fact ESCoSA decided that equity beta should be 0.8 in the ETSA Utilities case, but this was modified in the appeal made by ETSA.

The ESCoV in its recent water review[29] has stated that

> "The Commission has adopted a proxy of the equity beta of 0.75, based upon benchmark gearing of 60 per cent debt to regulatory assets. The Commission's decision is consistent with:
>
> • recent regulatory decisions in the water sector (0.81)
> • empirical evidence from the Australian energy sector (0.70)"[30]

In setting the water businesses equity beta at 0.75, the ESCoV opined, but without any justification that

> "The results of the review of selected regulatory decisions highlight the general view of regulators that the systematic risk faced by water businesses is less than energy businesses. The Allen Consulting Group also formed a similar view in respect of the Gladstone Area Water Board (GAWB): "GAWB will be subject to less systematic risk than say, electricity distribution network service providers, since compared with electricity, water demand is less correlated with domestic economic growth"[31]

This statement is purely based on a subjective or intuitive view and there is no quantitative support provided for any such view. However to use an equity beta of unity or higher as proposed by Envestra there is an implicit conclusion that gas distribution is seen to be a third more risky than water distribution, ostensibly because water demand is less correlated to domestic economic growth. In fact it could just as easily stated that as gas demand is seen to be **more correlated** to economic growth, it is therefore more predictable.

Regardless of this qualitative debate, to increase the equity beta by a third (ie from 0.75 to 1.0 or higher as Envestra has done) in spite of the quantitative and

[29] Water price review, volume 1, Metropolitan and regional businesses' water plans, draft decision 2005-06 to 2007-08, March 2005
[30] Ibid page 91
[31] Ibid pages 90 and 91

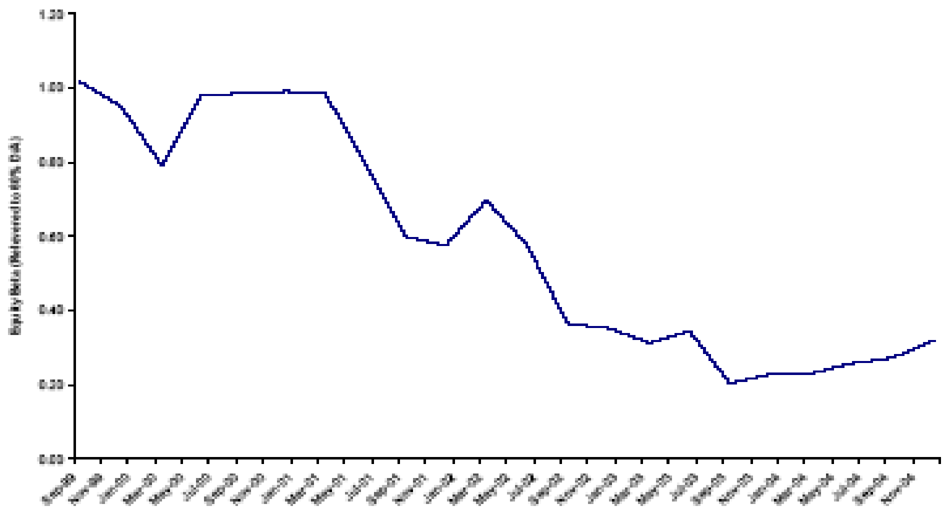
empirical analysis provided by the ESCoV in its “water decision” that shows the equity beta for electricity and gas distribution businesses is closer to 0.7, (even when allowing for the technology bubble).

In light of the comparative work by ESCoV in its water decision that the equity beta for energy is 0.7, it should be noted that the ESCoSA had originally determined in its Final Decision that the equity beta should be 0.8, but revised this to 0.9 on an appeal by ETSA Utilities. In its decision, ESCoSA considered that the equity beta of 0.8 was in fact justified by its analysis and the only reason ESCoSA gives for moving to 0.9 on appeal is that 0.9 is consistent with other recent regulatory decisions. This was the only reason ESCoSA gives for substantiating the change – ESCoSA did not accept any other reason put forward by ETSA Utilities than the one relating to regulatory precedent.

On the basis of the ESCoSA decision, supported by the decisions of QCA and IPART, Envestra should be guided by regulatory precedent and follow these other decisions.

The ESCoV provides the following chart which clearly shows (as with MRP) that there is significant volatility in the market which strengthens the view that regulators should be using recent data as the basis for setting equity beta.

Figure 9.1: Average Equity Beta for Comparable Australian Entities



Source: ESCoV draft decision, figure 9.1, page 297

Indeed the ESCoV points out that the group of companies comprising the equity beta calculated in figure 9.1 includes the companies AGLE, Envestra, the Australian Pipeline Trust, AlintaGas and GasNet – all of which have their gas transport assets regulated[32], and had the notional equity beta of 1.0 used in setting their previous regulated revenue. Thus the equity market itself has

[32] In fact most of the equity beta calculations are carried out on gas transport companies as most of the regulated businesses listed on the Stock Exchange are gas transport – few electricity businesses are so listed

recognized that an equity beta of 1.0 is too high and so implies an equity beta much lower, recognizing that the stability and certainty of the cash flow from such regulated entities warrants a lower equity beta.

The further discussion by ESCoV in the draft decision refers to the difficulty in assessing equity beta in light of such issues as the "tech boom and bust" which are regular events in the equity markets. Yet in Australia the "tech boom" has been in part replaced by a recent "mini minerals boom", indicating that to assess the impact of the "tech boom" in isolation is flawed. Despite this variation figure 9.2 in the draft decision looking at the equity beta in electricity distribution in the US, clearly shows that the equity beta averages some 0.6-0.7 prior to the "tech boom" and since that boom busted, it has averaged closer to 0.2. All of this data from comparative sources clearly indicates that an equity beta should be less than unity.

The NE Rules require the regulator to use comparative benchmark data from local and international sources for like industries, and further that the regulator takes guidance from other jurisdictional regulators. Envestra has elected to use higher levels for equity beta by reverting to using an equity beta which is clearly higher than international benchmarks and other Australian regulators are using at this time.

Envestra should set an equity beta which replicates the local market of like industries, international benchmarks for like industries and the recent decisions of other Australian regulators when setting equity beta. By using an equity beta of 1.0 – 1.1, Envestra is significantly overstating its risk profile.

Envestra should use an equity beta of no more than 0.9 (to comply with regulatory precedent as has done the ESCoSA after assessing the appeal by ETSA Utilities) and probably no more than 0.7-0.8 when assessing the local and international benchmarks (as did ESCoSA when setting an equity beta of 0.8 in its Final Decision on ETSA Utilities and recommended by the SA Treasurer in his response to the ETSA appeal).

The ETSA Utilities Appeal

It is important to note that under the appeal by ETSA Utilities, the SA Treasurer (in his role as the relevant Minister under the ESCoSA Act) advised the ESCoSA that the equity beta of 0.8 should be retained, and the SA Treasurer based this observation on work by Dr Martin Lally. In the Treasurers report it points out that the work by Officer and Gray referred to in the ESCoV draft decision is flawed, and when appropriate adjustments are made (as defined by Lally) then the outcome is an equity beta for electricity distribution between 0.75 and 0.82.

> "The Government considers that the equity beta of 0.8 adopted by ESCOSA in the Final Determination is within the expected range, given

current market estimates of betas and after appropriate consideration of the effect of the Final Determination in mitigating almost all of the systematic risk faced by ETSA Utilities.

To assist ESCOSA in considering the Review Application from ETSA Utilities, this submission includes an independent expert's review of the appropriate equity beta, authored by Associate Professor Dr Martin Lally[33].

Dr Lally has used a detailed analysis to calculate an appropriate asset beta for ETSA Utilities, before using the agreed gearing formula to calculate an equity beta of 0.75. It is noted that Dr Lally's approach provides a more reliable result as it draws upon a larger data set than that relied upon by Professors Gray and Officer, which compares a total of four Australian firms.

In addition, Dr Lally has reviewed the analysis of Professors Gray and Officer and has concluded that, after the removal of the flawed Blume adjustment (that has been uniformly rejected in other Australian regulatory decisions), their own data points to an equity beta of 0.82.[34]

In his paper Dr Lally concludes

"This paper has examined the appropriate equity beta for ETSA, at a leverage of 0.60. In view of the limited number of comparable Australian firms, US data is drawn upon, spanning fifteen years and involving nine sets of estimates with a median number of companies per set of 80. This yields an estimated asset beta of 0.3. In conjunction with the agreed gearing formula, and ETSA's leverage of 0.60, the resulting equity beta is .75. This is broadly compatible with ESCOSA's estimate of 0.8, and considerably less than ETSA's estimate of at least 1.

This paper has also examined the analysis of Gray and Officer, which invokes data from four Australian firms, and subjects the data and beta estimates to a number of adjustments. Leaving aside the insufficient number of firms examined here, it is argued that some of the these adjustments are inappropriate, and the result is to alter Gray and Officer's estimate from at least 1 to less than .82. Again, this is comparable with ESCOSA's estimate of 0.8.

The paper has also examined the Analysis of NERA, to the extent that it deals with issues other than the judgements of regulators. Five of their arguments are considered here. Of these, one is more comprehensively addressed by Gray and Officer, two are argued to be invalid, one

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[33] The Equity Beta for ETSA Utilities, Martin Lally, May 6, 2005

[34] Submission of the Treasurer of South Australia, Review of the Essential Services Commission of SA, Electricity Distribution Price Determination, undated but published in May 2005, page 17

> irrelevant, and the remaining point to have been applied at the wrong level."[35]

A review of the Allen Consulting reports on equity beta and the Lally report to SA Treasurer highlights that the calculations for equity beta are essentially those for a gas transport business as it is gas transport businesses which make up most of the Australian examples used and the S&P ASX Utilities index.

Based on the review of the data provided both before and after the ESCoSA decision, there is little doubt that the equity beta for an gas distribution business should be no more than 0.8.

Conclusion

Examination of equity beta and MRP by independent researchers (such as SACES, Allen Consulting, Capital Research, Lally) has clearly identified that the values traditionally used by regulators for these CAPM inputs are very much on the high side of long term averages and, certainly in the commercial climate of today, they are too high to use if the goal is to replicate current market conditions.

Supporting these specific studies, there has been a study[36] to examine a market comparison between the values used by regulators and what the competitive environment produces. This research work was based on analysis of over a decade or financial results of the largest 300+ companies operating in Australia. The study found that:-

> "The evidence from recent research indicates that a Market Risk Premium (MRP) of 6% and an equity beta (β_e) of 1.0 currently used by Australian regulators in the CAPM formula are too high, and that a MRP of 3-4% and an β_e of 0.3-0.7 are more appropriate assumptions, particularly in the light of recent capital markets developments."

It goes on to say:-

- nominal and real returns earned by Australian companies are lower than the regulated returns determined by Australian regulators for electricity (and gas) networks/businesses;
- Australian regulators use MRP data extending from over 100 years ago, and this does not realistically reflect the current and prospective outlook for the financial environment – more recent data should be used;

[35] The Equity Beta for ETSA Utilities, Martin Lally, May 6, 2005, page17

[36] "Further capital markets evidence in relation to the market risk premium and equity beta values used by regulators for regulated businesses in the National Electricity Market" December 2003, prepared by Headberry Partners P/L and Bob Lim & Co P/L for the Electricity Consumers Coalition of South Australia

- Australian regulators have disregarded the "conservative" rating of network businesses by determining an β_e of unity;
- Australian regulators are arguably in error in their use of the CAPM formula by:-
  - o applying a MRP generated from historical depreciated actual values to an asset value (of the regulated business) using the depreciated optimized replacement cost method; and
  - o applying a gearing of 60% debt and 40% equity when the gearing typically used in capital markets is as high as 77% debt.

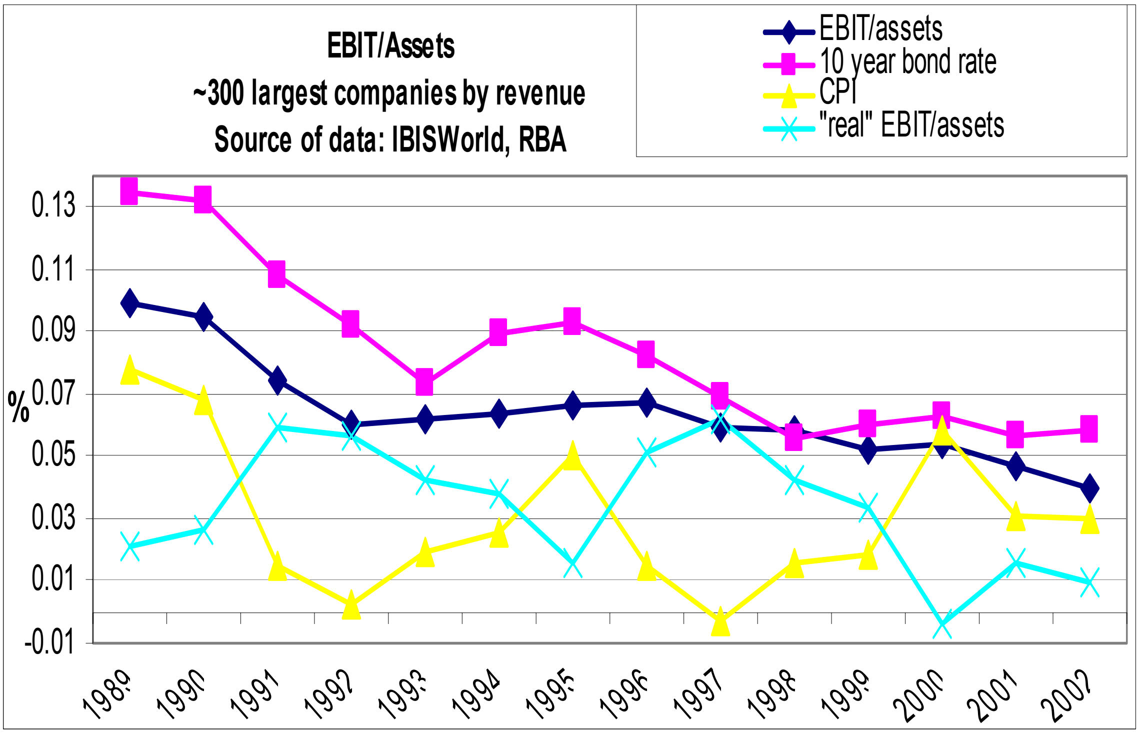
These figures for MRP and equity beta developed from the actual assessment of the market are in stark contrast to the values suggested by Envestra of MRP of 6-7% and equity beta of 1.0 to 1.1 to be used in the Envestra development of WACC.

Benchmarking of WACC

Regulation is a surrogate for competition. Therefore all regulatory assessments should be compared to the outcomes observed in the competitive world, and the setting of a WACC value is no different. To relay exclusively on sourcing inputs to a formula without verifying the outcome is poor scientific practice – all science requires verification of theoretical outcomes and Envestra (and ESCoSA) musty do likewise. Failure to do so can produce an unrealistic outcome, particularly when there is so much debate surrounding the values for inputs to the theoretical formula.

Envestra has not carried out any comparisons to assess whether the calculated figure they have developed has any relationship to outcomes applying in the competitive world.

The research shows that the "real" average EBIT/assets achieved by companies operating competitively varied between 0 and 6% over the past decade, averaging about 4%. Regulators have been awarding WACC's for the regulated energy industries since 1996. Comparing the WACC's awarded to the RoA's earned in the competitive market shows a marked disparity with "real" EBIT/Assets averaging 3% since 1996, compared to "real" pretax WACC's being granted of over 7%.



Source: "Further capital markets evidence in relation to the market risk premium and equity beta values used by regulators for regulated businesses in the National Electricity Market" section 3.

The ACCC in its review of TransGrid transmission revenue estimated that with a real pre tax WACC of 6.75%, this equated to an EBIT/assets of about 11%, clearly showing that returns earned by regulated industries exceed those of competitive enterprises.

What is necessary for regulators to carry out is a benchmarking analysis to ensure that the WACC they award is in keeping with the outcomes of the competitive market. Failure to do this exposes the regulated businesses to the risk of being granted a return which is too low, or a risk to consumers that the return which is too high.

The data used for this research is readily available and there is no excuse for regulators failing to benchmark their calculated outcomes. In this way regulators can ensure that their decisions do have relevance to the current expectations and outcomes earned.

Using the inputs proposed by Envestra, the real pretax WACC to be awarded will be between 7% and 9%. This is some 3-5% points above where actual "real" pretax market returns have been for the past decade.

ESCoSA should require Envestra to benchmark the calculated WACC to actual outcomes to ensure there is consistency between the awarded WACC and the market ESCoSA is meant to replicate by its regulation.

5 Growth forecasts

In its forecasts of gas usage, Envestra predicts a fall in gas demand over the next five years by about 0.2% per year for small users and an MDQ requirement fall by large users of 1% per year. Industrial use is the larger of the total demand equating to well over twice the gas usage of small users.

As gas and electricity usage is an indicator of total state growth (particularly of industrial growth) the forecasts of Envestra would indicate that South Australia is heading for recession.

In its development of gas usage forecasts Envestra points to a number of indicators:-

1. The State wide heating effect which reduces the demand for gas heating by domestic gas users and small commercial users. Envestra provides a chart to support its contention[37] which shows that the number of heating days per year is falling.

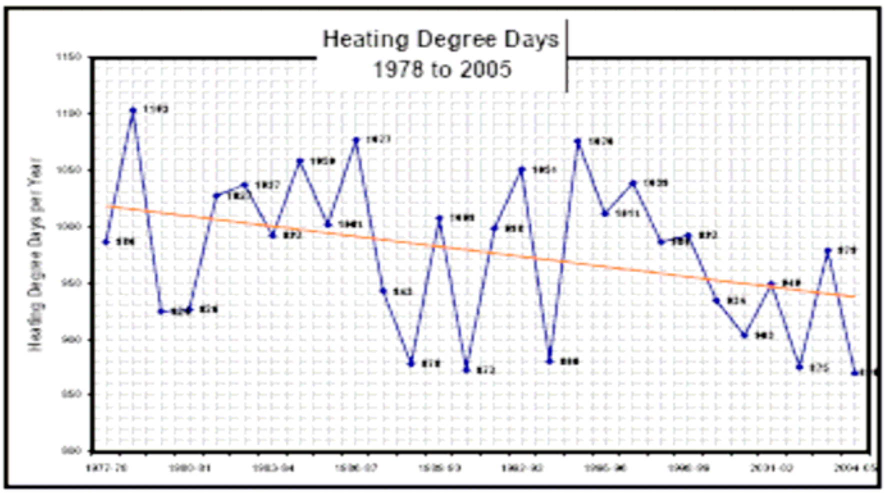


Figure 3.1

2. The increase in efficiency of heating appliances is given as a reason for falling demand but Envestra provides little quantitative evidence as to the extent that this reason provides for reduced gas usage.

3. Envestra comments that small industrial users are not sensitive to the changes in environmental temperature. They comment that:-

> "Demand increases over the forecast period, from 1.88 PJ in 2006/07 to 1.91 PJ in 2010/11, but at a lower rate than history.

[37] Envestra AA attachment Forecast Demand figure 3.1

> This reflects our view that competition from imports will constrain demand from small scale local manufacturing operations thereby reducing the rate of growth."[38]

The import of this comment is that Envestra predicts a 0.3% growth per year in small industrial activity in South Australia with the prime cause of this small increase being from imports (either form other States or from overseas).

4. Large industrial demand is forecast to reduce by 1% per year. As large industrial usage of gas is some 2-2½ times all other demand this has the greatest impact on gas usage in the state (other than that for power generation. Certainly to forecast a sustained reduction in demand by industrial users is effectively forecasting a fall in GSP.

   Envestra provides an intriguing scenario that the loss of MDQ (ie the amount of capacity booked by large users) cannot be correlated to a reduction of gas consumption.

   > "Moreover, MDQ is poorly correlated with macroeconomic drivers such as Gross State Product and disposable income making redundant an econometric approach to forecasting. Large increases and decreases in MDQ occur as the result of relocation, expansion or shutdown of businesses. Prime examples of this are the loss of 6,500 GJ of MDQ at Lonsdale due to the shutdown of the Mobil oil refinery, the shutdown of the Ion Automotive plant at Wingfield and the relocation and expansion of the Coopers brewery to Regency Park. All of these were not incorporated into the forecasts of MDQ for the Demand Haulage Service in the current Access Arrangement Period."[39]

   What these words fail to provide is that regardless of the loss of large volumes of gas demand, Envestra considers that the closing of facilities does not indicate a reduction in macroeconomic drivers! What Envestra fails to consider is that the heavy premium placed on gas transport in the southern gas zone of Adelaide may have been a significant contributor to the loss or movement of large users out of this gas zone.

   Envestra points to the potential losses of a number of customers in the new period

   > "Envestra is not aware of any major expansions in the regulated network, hence no additional MDQ has been incorporated into the projections over the forecast period. The known curtailments

[38] Envestra AA Forecast Demand page 8
[39] Ibid page 3

and shutdowns are listed below along with the resulting impact on MDQ for the forecast period:

(i) Mitsubishi's Lonsdale foundry: 1,900 GJ of MDQ has been deducted from the Southern zone

(ii) Ion Automotive – Wingfield: The Administrator has advised that this facility will be shutdown[1]. 519 GJ of MDQ has been deducted from the Northern zone MDQ.

(iii) Ion Automotive – Plympton: The Administrator has advised that production at this facility will be scaled back due to the loss of the contract with Holden. MDQ in the Central zone has been scaled back from 1,300 GJ to 881 GJ.

To account for the natural loss and addition of Users in any year we have assumed that the net increment to MDQ is zero - additions equal losses."[40]

This statement raises two contentious issues.

- The first is that if there is no expansion of the industrial network, why has there been proposed such a large capex investment which would be expected as large industrial gas users use over two thirds of the total gas transported on the Envestra network.
- The second is that if there is no expansion of the large industrial gas demand forecast, how does this equate to the fact that the SA Government points to a large number of growth projects and economic indicators such as[41]:-

- SA has secured more than half the work on the Navy's **$6 billion Air Warfare Destroyer program,** creating an estimated 3,000 new jobs. Government committed more than $140 million toward infrastructure and skills development.
- **Economy grew at 4.3%** in 2003-04, above the national average and trailing only W.A. and Qld.
- **Economic Growth summit** lead to action in areas of infrastructure, population, exports, education and government efficiency as well as new investment in broadband, biotechnology and naval defence consolidation.
- **Fall in net number of people leaving SA** to find work interstate.
- **Record employment** levels with unemployment at its lowest since monthly surveys began further supported by **$22m South Australia Works** program and a **Regions at Work** program involving business, employers and trainers in 17 regions.
- Assisted **OneSteel's future** development of Project Magnet, designed to extend the life of Whyalla's OneSteel operations until the year 2027.

[40] Ibid page 4
[41] SA Government website http://www.ministers.sa.gov.au/achievements.asp#1

- Secured 10-year extension for **Clipsal 500**.
- Opened **$9.2m Plant Genomics Centre** that will house the $55m Australian Centre for Plant Functional Genomics (ACPFG).
- **Carnegie Mellon** to establish a branch of the internationally recognised University in Adelaide.
- **Private business** investment in SA outstripping National business investment.
- **$15 billion** of major projects in the pipeline, not including the Air Warfare Destroyer contract and planned expansion of Olympic Dam.
- **$8 million** over four years to create Australia's largest manufacturing technology research centre, the **Mawson Institute for Advanced Manufacturing** at Mawson Lakes.
- **$2.5 million** to establish the **Australian Minerals Science Research Institute** to help develop new technologies for minerals processing that will lead to lower costs, higher yields and better environmental outcomes
- Introduced the **PACE (Plan for ACcelerating Exploration)** plan - a five year, **$22.5 m** initiative to encourage mineral exploration in SA.
- New **Marine Innovation SA program** to help SA double value of seafood industry to $1 billion by 2010.
- Signed agreement with Newport Quays for **$1.2 billion Port Adelaide Waterfront Redevelopment**.
- **$600m City Central project** includes Government lease of space in 5-star green office block – ensuring start of SA's biggest CBD development for 15 years.
- Assistance for winemaker Beringer Blass for its 10-year, **$100m investment in a new bottling plant at Nuriootpa**, creating jobs and helping boost exports.
- Commenced construction on the new $14.3m **wastewater treatment** plant at Whyalla and the $42m wastewater treatment plant for Victor Harbor.
- **$5.9 million** to treble the size of the Thebarton Bioscience Precinct and expand South Australia's biotechnology sector.
- **$21.6 million** marina and boating industry precinct planned on the Port River at Largs North.
- Expanding the **Edinburgh Parks** industrial precinct by 500ha by purchasing adjacent Commonwealth land.
- Committed more than half a billion dollars new money to **upgrade SA's public hospitals** including $110m to completely rebuild our hospital mental health facilities in all areas.
- A new **Centre for Innovation in Cancer Prevention and Control** to be built at the Flinders Medical Centre for **$14.5 million**, combining research, patient care and prevention (Budget 2005).
- More than $450m injected into the **upgrading of State school buildings, facilities and equipment**.

Whilst there are some acceptable reasons for Envestra commenting that gas demand might fall (such as the clearly identifiable number of fewer heating days per year) overall it would appear that Envestra has deliberately understated the potential increase in gas usage, as by doing so it can increase tariffs (and total revenue from regulated and unforeseen revenues) and so benefit from the higher revenue that results from a burgeoning economy.

Envestra must be required to provide evidence that its demand forecasts are based on a sound methodology, and that they are derived on a reasonable basis consistent with section 8.2(e) of the Code.

6. Development of the Asset Base

The development of the new period asset base requires four basic inputs (in accordance with sections 8.8 and 8.9 of the Code:-

- Asset value at the start of the current period.
- Incorporation of approved capex (that which is demonstrably efficient and prudent) as it occurs.
- Deduction of depreciation of the approved assets against an agreed formula (eg agreed asset life and straight line depreciation.
- Deduction of any stranded assets from the asset base.

Starting Asset base

Envestra advises that it has used the asset value at the start of the current period based on the SAIPAR valuation as at 98/99. In fact SAIPAR sets the asset value at $709.7m in 2001/02 in its final decision[42] and this value should be used rather than the $710.9m used by Envestra

Past Capex

Envestra has used the actual past capex over the period without demonstrating that the capex was prudent and efficient. Envestra must provide additional information to prove that the capex was in fact prudent and efficient.

WP makes the comment that there was:-

> "….a significant tightening up of the process since the implementation of Maximo, but the new arrangements are still being bedded down."[43]

which implies that the process used by Envestra may not necessarily have resulted in prudent and efficient investment. With this additional concern Envestra must provide detailed support for prudency and efficiency of its capex.

There is inconsistency between the amount of past capex shown in AAI table 4 providing a statement of incurred capex to 2005, and the development of RAB for the opening asset values in AAI table 10. These tables should be further reconciled with the benchmarking studies by WP.

Depreciation

Envestra states that the depreciation schedule provided in table 11 of its AAI[44] is in accordance with SAIPAR allowed depreciation. The SAIPAR final decision

[42] SAIPAR Final Decision table 5.8.11.1
[43] WP report page 22
[44] Envestra AAI page 24

makes reference[45] to protected steel mains having a life (EUL) of 120 years, unprotected steel of 60 years, and polythene of 60 years.

Envestra should demonstrate how these amounts are incorporated into the average EULs included in its table 11.

Asset stranding

Envestra makes the observation in its forecast demand paper (see above) that there were a number of consumer closures and transfers, particularly from the southern gas zone, including the Lonsdale area. However, Envestra has not reduced its value of its capital base to reflect the optimization of the network to reflect the lower demand from the southern gas zone. As Envestra points out, some 6.5 PJ of gas is no longer being transported to the southern gas zone (this represents over 20% of the total large industrial gas demand) and in accordance with Code provisions Envestra should have optimized the network assets in this area.

We note that:-"Section 8.9 of the Code provides for redundant capital to be removed from the capital base:

> "With effect from the commencement of the subsequent Access Arrangement Period, the Relevant Regulator may reduce the Capital Base by an amount representing:
>
> a) any assets that in the reasonable opinion of the Relevant Regulator have ceased to contribute to the delivery of Services;
>
> b) any assets that in the reasonable opinion of the Relevant Regulator are *likely* to cease to contribute to the delivery of services;
>
> c) any assets that have been transferred by AGLGN or in relation to which AGLGN has entered into a binding agreement for its transfer;
>
> d) any assets that in the reasonable opinion of the Relevant Regulator have decreased in value because of a decrease in its utilization resulting from a decline *or likely* decline in the volume of sales of the Service; or
>
> e) any assets that in the reasonable opinion of the Relevant Regulator have decreased in value because of a *likely* decrease in its utilization resulting from a decline or likely decline in the volume of sales of the Service.
>
> In assessing the reduction in the Capital Base due to a decreased utilization of assets resulting from a decline in the volume of sales of a Service, the Relevant Regulator may take into account the reduction in Total Revenue

[45] SAIPAR FD 5.8.7

> and any possible increase in Tariffs paid by users resulting from the decline in utilization of assets."

The issue of redundant capital is not new and there is regulatory precedence in that the NSW IPART[46] had recently determined that:-

> "……the Tribunal has identified redundant capital on the Wilton to Wollongong Pipeline with a value that equals to 20 per cent of the value of the capital base of the pipeline at the commencement of the proposed access arrangement. The Tribunal requires this redundant capital to be removed from the value of the capital base for the Wilton to Wollongong trunk lime at 1 July 2005…"

The NSW IPART's decision was based on its assessment that there was a decline in sales volume (both contracted MDG and overall throughput) of the relevant pipeline in 2000 and 2001 (which has continued to fall), and it was required to act under section 7.6.1 (d) and (e) of the Code in relation to the capital redundancy mechanism.

Thus as a minimum there should be an allowance in the development of the RAB carry forward for a reduction in RAB due to asset stranding and optimization, at least in the southern gas zone.

Envestra should also include for any other optimizations, disposals and strandings which occur throughout the network.

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[46] NSW IPART, Revised Access Arrangement for AGL Gas Networks, Final Decision, April 2005

7. Cost allocation between classes of consumers

The approach to the access arrangement proposed by Envestra is based on the costs allocation approach that it used in the previous review. This resulted in the costs for "demand" customers being excised and a **notional** network developed. Thus implicit in this access arrangement is that Envestra has continued to use exactly the same approach and costings as it used in the review by SAIPAR.

The notional network for the SAIPAR review was costed by Envestra and an opex attributed to it. ECCSA approached SAIPAR about this approach pointing out that the approach was flawed on two counts:-.

- That the costs developed by Envestra were incorrect and did not reflect actual costs.
- That the approach was not cost reflective in that it allocated a share of the costs at the extreme point of standalone for just this class of consumer and did not reflect that a network benefits all consumers to a greater or lesser extent. To allocate standalone to one class of consumer and not to all is discriminatory and inconsistent with Code provisions.

These issues in relation to the SAIPAR review are developed further below.

The network design

Since the ECCSA approach to SAIPAR, it has become even more apparent that the cost allocation does not reflect the actuality of the network design. The gas southern zone approach proposed by Envestra assumes that the network in Adelaide has a multitude of small gas paths which as consumers are located further away from the points of injection they require an ever increasing share of the assets to provide for the supply.

In fact the gas assets have a single backbone of supply from north to south. This was to provide for the very large demand of Mobil's Port Stanvac refinery and a number of other large demands in the same area such as the (then Chrysler now Mitsubishi) car manufacturing plants. Envestra makes reference to this backbone in its discussions on growth where it refers to the loss of the demand from Mobil, Mitsubishi, Ion and the relocation of other plants.

This means that rather than all demand customers in the southern zone utilising the assets in the two zones north of the southern zone, in fact the only assets used by southern zone customers which are also used by the other zones is a single high pressure main running north to south with each zone drawing off this main north south pipeline. When this approach to cost sharing is followed, the disparity between the three zones reduces remarkably.

It would appear that Envestra used the concept of the multiple feeds through the northern and central zones to the southern zone as a means to reduce the potential of northern zone customers looking to bypass Envestra assets which they consider were too expensive because Envestra had used the standalone cost allocation in order to bias its gas revenue collections. By Envestra increasing the costs of the standalone approach for demand customers and then allocating the greater share to the southern zone customers who had no alternative (such as bypass) to minimise their costs, Envestra was able to significantly increase costs to demand customers and at the same time minimise the potential for gas bypass by its northern zone customers.

In its Final Decision allowing the notional network approach to be used for setting the demand customer allocation, SAIPAR made reference to the approach taken by AGLGN and IPART for Sydney gas tariffs (the so-called "coastal postal" tariff). During that regulatory debate IPART initially agreed with the proposed approach of AGLGN to use a similar zonal concept to that proposed by Envestra for Adelaide. After deeper examination of the issue, IPART recognised that the physical sizing and layout of the network was not reflected in the zoning concept. Whilst AGLGN overcame this problem by developing a set of unique cost reflective tariffs for over 400 major users that quite closely reflected actual usage of the network, Envestra appears to have found it difficult to address the same issue with only 140 major users. We believe that attempting to simplify the tariff structure too much has resulted in perverse outcomes.

The headline outcome of the Envestra approach to cost allocation should be considered as a factor in the closure of a number of large gas customers in the southern zone and encouragement of new entrants (such as the Amcor bottling plant) to connect directly to the transmission system rather than use the Envestra network. This approach by Envestra has contributed to an increased share of costs for all consumers resulting from the loss of major users of gas, which if they had remained viable, would have contributed to the overall costs of the gas network, so that all customers could receive a reduction in tariffs.

Envestra should not be rewarded in any way for this approach which will result in existing gas consumers facing increased costs. Envestra points to this issue to support in its view that there will be little growth in gas consumption to offset the significant lost demand (it has caused).

The notional network approach to cost allocation

The concept of using the notional network is driven by an hypothesis that demand customers would appear to be the largest user of the system, based on volume of gas transferred. In fact, on a capacity basis, "volume" customers utilise the network capacity (specifically the high pressure and transmission elements) to a greater extent than do demand customers, although for relatively short periods of time. Thus, the approach proposed by Envestra allows a "free ride" to all volume customers by, Envestra providing with the use of the system at marginal costs. This is in contravention of the Gas Code that stipulates that costs should be allocated equitably on a cost reflective basis. Because of this, it is suggested that when assessing the costs for demand customers, errors and approximations should be biased in the direction of reducing the costs of the notional network, and towards true cost reflectivity with all users of the system.

In analysing an appropriate cost allocation methodology for cost allocation there is an implicit acceptance that the Envestra system should not be assessed on the total amount of gas passing through its system each year. Envestra does not sell gas on an annual basis; it provides a transport system that carries the required amount of gas *at any point in time.* As such the Envestra system should be analysed more on an MDQ (or even an MHQ) basis, as this is how the system is designed and operated, with much less reliance placed on the total volume of gas transferred. This means that when utilising annual gas usage by domestic and commercial ("volume") customers it is inappropriate for allocation of system usage on an annual basis while demand customer (stand-alone) usage is to be valued on a different (MDQ) basis.

In assessing the approach to cost allocation used by Envestra in the current AA, there is an implicit acceptance that the risk of "demand" usage is higher than "volume" usage. We would note that "volume" demand is extremely weather sensitive, whereas demand customers usage of the network is much more predictable.

SAIPAR allowed Envestra a method for tariff setting that not only is biased to prevent bypass (which is usually an option only for large gas consumers) but is also over compensating for other locational issues. All users should pay for usage in proportion to their usage *of the network,* rather than the volume of gas consumed (and this is the regulatory approach adopted in other jurisdictions). Thus, whilst it appears a simplistic solution to a complex issue, the standalone approach clearly discriminates against a small number of users (the demand customers), and allows another class of users (volume customers) a "free ride".

Whilst the Gas Access Code requires cost reflectivity for asset usage, it also requires cost reflectivity for non-capital costs (or attendance on the assets). It is accepted that the current tariff structure should reflect the greater usage of assets to deliver gas to the Southern region, but those costs which are not related to asset usage (eg A&G) should be cost reflective to each customer (eg apportioned by numbers of customers, rather than the value of assets used). To overcome this inconsistency, a greater fixed payment in the tariff representing the customer share of fixed non-capital costs is a more appropriate way to allocate costs of this nature.

Envestra has cleverly utilised the implications of the difference between MDQ and ACQ to its benefit in the approach to allocating costs. In the summary of usage, Envestra shows that "volume" customers are 30% of total network demand on an annual basis (SAIPAR FD table 2.1.1), but as most "volume" gas is consumed in the winter months, the actual usage of the network by volume customers on an MDQ basis can be 3-4 times (even higher) than the implied

ACQ basis. On an MDQ basis it would appear that the network rather than the 25 PJ/a shown, probably has a system capacity of over 60 PJ per annum (actual 98/99 factored for approximate capacity factors), of which the demand customers would require less than half, rather than the amount of 70% of total implied by the ACQ summation.

In other words the mains needed to service the “volume” customers on a “standalone” basis would have to be the same size *or larger* than the mains to deliver gas to the demand customers due to the MDQ requirement of the volume customers. Thus the operation and maintenance requirements for the stand-alone notional network and the “as-built” network would have to be remarkably similar.

In its valuation of the notional network Envestra then goes on to use MDQ for all demand customers, maintaining the ACQ implied as the mechanism for allocation of costs for “volume” customers.

The ACQ of demand customers bears a relatively close relationship to their MDQ, particularly when averaged across all demand customers. Thus what is missing from the AAI is the analysis of MDQ for each customer class. This will highlight that the proposed allocation method of costs for demand customers more than likely results in them being levied an even higher share of the costs than appears on initial review.

Actual costs for a notional network

Envestra has implicitly attempted to allocate such shared resources as A&G, marketing and O&M by assessing a “standalone” network. While it is feasible, but eminently impractical, to contemplate the building of a network to supply gas to just 140-150 customers, it is possible to establish the cost of providing that facility.

However, to attempt to allocate overhead and attendance resources is totally inappropriate for such a small network, and sensible benchmarking will demonstrate that the attempt made by Envestra shows that the proposed costs are out of all reasonable bounds. This is typified by the value of the non-capital costs for the notional network being greater than the sum of the capital costs plus depreciation, whereas capital costs plus depreciation costs for gas systems are always many times the value of non-capital costs!

As an example, if the entire non-capital costs suggested by Envestra were comprised of employees, $6M would provide nearly one and a half Envestra employees per customer to carryout the necessary attendance of the notional network. As the notional network will never be in the competitive environment, there is no reason why Envestra cannot nor should not be required to divulge all of its costings for these “notional” non-capital items. ECCSA in a submission to SAIPAR carried out its own assessment that a standalone network should cost much less than the assumed $12m Envestra attributed to the stand alone network for demand customers. SAIPAR never examined this valuation in its Final Decision, or carried out any assessment of its validity, accepting completely the valuation estimates by Envestra. ESCOSA must not avoid its responsibility to undertake such an assessment.

As demand customers are being required to pay tariffs based on a notional network, Envestra must be required to provide as much detail to substantiate its claims as if the notional network is a real network and subject to the Code. This they have failed to do.

In an attempt to utilise the information provided in the SAIPAR review as Envestra does not address this issue at all in its current AAI, the information released can be easily summarised with, certain deductions made, and questions asked.

1. The notional network (NN) incorporates negotiated services that have their own recovery mechanism. *What is the income from these negotiated services? What is the asset requirement to provide these services? Is it reasonable that these negotiated services should be permitted to "free ride" off the standalone value?*
2. The NN had 142 customers with an annual demand of 17,129 TJ (excluding farm taps). The implied loss of load from demand customers from 1999 to 2001 was 14 customers with a total annual demand of some 8000 TJ, nearly half the residual demand customer load. *Do the costs for the notional network include or exclude the load lost over the previous two years to incorporate redundant and stranded assets?*
3. The NN would have less than the 174 km of transmission status pipelines, and only a small proportion of the 2091 km of high-pressure tier pipelines because large pipelines are built to supply large consumers. The value of the notional network is 6% of the total network value (see point 6 below) implying a length of pipeline of about 400 km for the notional network. *What is the total pipeline length of the notional network? Does the new AAI accommodate the redundant and stranded assets from the lost customers in southern zone during the period?*
4. The NN would be constructed of steel (as the SUG for demand customers is assessed as zero). *Is all of the notional network steel? Is it made of protected or unprotected steel?*
5. It has 95% of its assets in the Adelaide region, with ~2% in each of the Port Pirie and South East regions reflecting perhaps 1 - 3 customers in each of these regions. *What is the commercial impact of customers outside the Adelaide region?*
6. It would have a value assigned of some $40-45M, based on the high end WACC of ~9.75% claimed by Envestra and the stated return on assets of $4.1M claimed by Envestra. This assessment replicated by using a 400km length multiplied by the DORC/km value from SAIPAR

FD table 5.7.1. *What is the asset value assigned to the notional network? How was this derived?*

7. The useful life (to set depreciation) for the Envestra assets is 60-120 years, depending on the material of construction, implying a depreciation rate of less than 2% on a straight-line basis. This implied rate is supported by the amount of accumulated depreciation estimated by Envestra over the past 30 years or more (SAIPAR FD table 5.2.1). This would indicate the depreciation allowance for the demand assets valued at <$45M should be less than half the nominated $1.7M for the notional network. *What is the depreciation rate used for the notional network?*
8. The DORC asset value of the total network (as assessed by Envestra – the same basis as that used for valuing the notional network – is $766M. The asset value for the notional network is ~$45M, approximately 6% of the total DORC asset valuation. *Has the asset valuation of the notional network been depreciated to the same implied age as the actual network?*
9. The capex claimed by Envestra as part of the asset value for the actual network is ~3% of the Envestra DORC value. With the declining numbers of demand customers, it is unlikely that capex is needed for the transmission or high-pressure tiers. *How much capex has Envestra included in the total asset value for demand customers? Envestra states in its 2005 AAI that there is an overall loss of customers. Why would capex be needed?*
10. SAIPAR has required a number of adjustments to the asset valuation as part of the Final Decision. *Is Envestra required to use the same basis for valuation of the notional network or just the WACC reduction?*
11. Envestra nominated a “non-capital” cost of $6M for all demand customers and SAIPAR has allowed a total of “non-capital” costs of $31.8M for the whole system (excluding SUG which is not attributable to the assets used by demand customers). ie demand customers contribute 18.9% (nearly one fifth) of the total “non-capital” costs excluding the non-applicable SUG. SAIPAR has not benchmarked the “non-capital” costs associated with the notional network. *Is Envestra required to benchmark these “non-capital” costs for the notional network?*
12. Allowed in the non-capital costs is an amount for marketing. *What allowance for marketing is included for the notional network? Should this be allowed as a cost for existing customers of a fully committed system?*
13. The NN has a non-capital cost allowance greater than capital costs plus depreciation, which is not consistent with the same relationship for other networks. *Will Envestra be required to substantiate the non-capital costs for the notional network?*

Independent work carried out reveals that the costs proposed by Envestra for the standalone network are grossly overstated.

1. Of the overall non-capital costs for the system (SAIPAR FD table 7.2.1 99/00), A&G comprises 17%, marketing 15% and operational 68%, approximately one third overhead and two thirds operational. It should be noted that A&G and marketing activities are more related to customer numbers than other factors whereas operating costs are more related to length of pipeline installed. This analysis is supported by the relationship of O&M services as an element of non-capital services as shown in SAIPAR FD tables 7.2.4 and 7.2.5. SAIPAR FD tables 7.2.4 and 7.2.5 quote the O&M and A&G costs per GJ calculated by Envestra for each service, implying some reasonableness of this allocation. When these same numbers are presented on a customer and pipeline length basis, they present unacceptable comparisons.
2. Benchmarking is an integral and essential aspect of the Code. There has been no attempt at benchmarking the costs of the notional network. The information to carry out the following assessment was only made possible by the extent of information made available in the SAIPAR Final Decision, and could not have been done prior to the issue of the SAIPAR FD. With the limited information provided, benchmarks for the notional network reveal some outrageous comparisons.

    a. NN non-capital costs exceed the revenue from the capital items plus depreciation. This is totally inconsistent with the revenue make up of the total Envestra network and other networks where capital costs plus depreciation by far exceed non-capital costs.
    b. NN non-capital costs per customer are $42,000, compared to the same allowance for the whole network of $98, a benchmark already 25% above those of the equivalent Victorian networks.
    c. NN non-capital costs per GJ are $0.35, comparable to the all groups of the Victorian networks, and only one fourth of the Envestra all groups.
    d. NN non-capital costs per km are $15,000 based on 400 km of pipeline. This is 4-5 times the benchmarks of Victorian networks and the Envestra (SA) network.
    e. NN non-capital costs for the notional network as a proportion of the total network (excluding SUG), is 20%. This compares very unfavourably with customer numbers (<1%) and km of pipeline installed (6%).
    f. NN A&G costs of $1M (see point G2) are $7,000 per customer compared to $10-20 per customer for the Victorian networks, and $60 per TJ, about half of the all groups of other networks
    g. NN A&G costs of $1M (see G2) become $2,500/km, 2-4 times equivalent costs for the comparable networks.
    h. NN network marketing costs of ~$1M (see G2) becomes $6,500 per customer, *or one marketing Envestra employee for every five demand customers.*

i. NN O&M costs of $4M become $28,000 per customer (nearly one full time Envestra employee per customer), or $10,000 each year per km of pipeline. This compares unfavourably with the DORC per km allowed for the value of the network in that it is equivalent to the cost to build the pipeline each 10 years. The allowance for the total network for O&M costs is $3800/km.
j. When the AAI is provided for the notional network, other benchmarks can be calculated and compared to reality.

Conclusion

Whilst the principle behind allocating costs for demand customers on a "standalone" basis simplifies cost allocation, and allows Envestra to structure a tariff that minimises the opportunity for large users of gas located near the "citygate" to bypass the system, it would appear that little effort has gone into ensuring that the costs to be allocated to this customer class do in fact replicate reasonable costs, whether for a standalone system (which gives no benefit from sharing costs with a large customer base) or indeed for a true cost reflective sharing of costs which is a requirement of the Code. This methodology is heavily biased against demand customers.

Appendix 1

The regulatory framework surrounding the application: ECCSA Response to Envestra comments

In Section 3 of the access arrangement information application, Envestra refers to a number of legal interpretations of the Gas Access Code and to recent decisions relevant to the present review.

Envestra proffers advice that the regulator (ESCoSA) must either accept or reject the basis of the application, and not seek to interpolate its own views as to the appropriateness of the bases used by Envestra. Specifically, Envestra refers to the use of the CAPM to develop the WACC and the method used to value its assets.

It is accepted that the regulator has a difficult regulatory task under the Gas Code. But the Code permits a significant degree of discretion, both to the asset owner and to the regulator. Equally, the Code does require the regulator to balance the needs of the owner with those of the users of the monopoly asset. However, as many of the various approaches permitted in the Gas Code are essentially subjective assessments (eg the DORC method for asset valuation, and the values used for the development of the WACC in the CAPM such as equity beta and equity risk premium) the regulator is required to balance calculated outcomes with those extant in the real world of commercial activity.

Thus whilst the regulator is not able to change a permitted approach used by the applicant, it can modify the outcomes by comparing the calculated outcomes with commercial reality.

The GasNet decision as interpreted by Envestra
Envestra assumes that the outcome of the ACT decision on GasNet effectively precludes the regulator from assessing whether the WACC calculated by the applicant is reasonable, providing that the WACC calculation in the application is correct. This is a rather broad interpretation, as the development of the WACC has in its parts a number of very subjective assessments for the input values. The regulator is required under the Gas Code to balance the interests of users and asset owners. The only way it can fulfil this requirement is to assess the reasonableness of each of the assumptions and to benchmark the outcome with commercial reality. A failure to carryout such an assessment would be a breach of the Gas Code itself.

The EAPL decision as interpreted by Envestra
Envestra points to the comments made by ACT to ACCC in relation to the approach made by the ACCC valuation of the EAPL pipeline. It should be noted that this decision by the ACT is being appealed by the ACCC to a the Full Bench of the Federal Court

Notwithstanding this appeal, Envestra assumes that because it decides that the asset valuation methodology will be based on the DORC approach, that this provides a firm and undeniable outcome amount. This is incorrect. The DORC asset methodology (along with many other methods for assessing asset values such as Deprival Value and Optimised Deprival Value) is essentially subjective. It constitutes a belief – admittedly by an expert – as to what might be the replacement value if such an asset was to be built. Unfortunately the only way an accurate figure can be developed for an asset value is by either building it or valuing it on what someone will buy it for.

As regulators have seen many different values for the same asset prepared by different (and even sometimes different values by the same) expert, this throws some doubt as the accuracy of the subjective assessments being provided by access arrangement applicants. In order to balance the interests of the asset owner and the users of the monopoly asset, the regulator must take guidance from a number of sources to ensure that the optimum value is in fact used. Thus the decision by the ACCC to eliminate a construction contingency in the asset valuation reflects its assessment of the validity of the DORC valuation methodology when this was compared to other commercially available benchmarks.

<u>The Epic (SA) decision as interpreted by Envestra</u>

Envestra concludes form this decision that the Gas Code does not direct the regulator to seek the minimum cost to provide the service. This is accepted, but equally the Gas Code is not intended to allow the asset owner of a monopoly service to receive monopoly rents – the regulator is required to balance the interests of both asset owner and asset user. Thus the regulator must assume that the asset owner will seek economically efficient costs for inputs into the development of the operating costs, and will not pay a premium to a third party.

This issue is of particular concern where the asset owner is not the operator (as in the case of Envestra where the operator is a related party) or where there is a large incentive program. In such cases there is the additional concern that a payment by Envestra to its related and incentivised party might not be the lowest complying cost and therefore allow the transfer of excess funds. By requiring the lowest possible complying cost to be the basis for inclusion in the regulatory revenue has the benefit of overcoming such concerns.

<u>The Epic (WA) decision as interpreted by Envestra</u>

Envestra concludes from this decision that it is not only the “abstract economic principle”[47] that should be the basis of an assessment, but the actual amount paid for an asset. This view is the opposite of that at which Envestra arrived at from the EAPL decision, where Envestra concludes that the amount paid for the asset should have been ignored. It is also an antithesis to the DORC Methodology, which is the upper band for valuing assets under the Code.

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[47] Envestra AAI page 13

It was quite clear from the Epic (WA) decision that Epic had paid an amount based on an unsustainable tariff, and therefore is considered to have paid too much for the asset. It should be noted that the WA regulator did take into consideration the amount paid for the asset, but recognised that in balancing the interests of the owner and the user of the monopoly asset, that there was no reasonable basis that the regulator could accept the purchase price as the main determinant.

After all if this was to be the case, we would see the regular sale of these monopoly assets through related parties, consistently driving the purchase price upwards.

The Productivity Commission Review of the Gas Code as interpreted by Envestra

The PC has reviewed the Gas Code and made a number of recommendations. Many users find the PC review conclusions are so focused on the detail of the Gas Code that they lack appreciation of the wider implications of their recommendations which was part of their brief. However, the point made by Envestra regarding the PC review is supported.

The PC does in fact highlight that the development of the WACC requires a number of imprecise inputs to the CAPM formula. It is the valuation of these individual inputs that create extensive debate. Once a value is assigned to each of the inputs it is the outcome that creates further debate. Envestra implies that this leads to "regulatory error and … less than efficient outcomes"[48].

Envestra then concludes that this requires the regulator to err on the side of higher (i.e. to benefit Envestra) then a lower outcome. As the regulator has the responsibility to balance the competing requirements of the asset owner and the asset user, the regulator should assess the comparative outcomes of both parties to assess whether there is a need to err on the higher side. As developed later in this submission, it would seem that Envestra is achieving a higher return on its assets than those users are in their own businesses.

The MCE review as interpreted by Envestra

Envestra points to the potential that the MCE might change the Gas Code, presumably to the detriment of Envestra. Equally users of the Envestra assets might well be disadvantaged.

That change might come should not be the basis to award increased revenues. The regulator should carry out its tasks on the basis of what it is required to do and not attempt to second guess what might be.

[48] Envestra AAI page 15

Envestra conclusions

Envestra concludes its assessment of these recent regulatory decisions with the following comments:-[49]

- The function of the Regulator is not to determine the precise level of efficient costs for a regulated business. Rather it is to determine whether Access Arrangements proposals made by a Service Provider are consistent with the Code and whether costs fall within a plausible range;
- Regulators need to recognise the inherent uncertainty in replicating competitive markets, and aim to achieve a balance between the costs of prescription and the benefits; and
- The costs and benefits of a poor regulatory decision are asymmetric. The Productivity Commission, the 2004 Queensland 'Somerville' Report, and the recent decision by the Queensland Competition Authority in relation to the Dalrymple Bay Port all recognised the long terms costs of under-investment in infrastructure and the impacts that the regulatory regime can have on incentives to invest.

These conclusions cannot be sustained.

1. In order for the regulator to determine whether the outcome of the application meets the requirement to balance the interests of owner and user, it must determine what an efficient outcome in fact is. Once the regulator has established its own view of efficient costs, it is extremely unwise to then decide to award a single value away from that value, as to do so will result in a bias toward one or other party.

2. Whilst it is difficult to replicate competitive markets, that is the whole purpose of regulation – regulation is a surrogate for imposing commercial pressures on entities not exposed to such pressures, such as monopolies. The regulator must approach the regulatory process as an attempt to impose commercial pressures on monopoly assets. A failure to do so abrogates the whole purpose of regulation.

3. The asymmetry of regulation is in favour of the regulated business. It knows its core business better than the regulator and is therefore able to manipulate the provision of information to its own benefit. Envestra points to recent assessments (Somerville report and the QCA decision on Dalrymple Bay) as supporting its claims for increased capex and higher returns. What Envestra does not say in relation to these assessments is that:-

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[49] Ibid page 16

- The Somerville report highlighted that investment by the government owned electricity distribution businesses had been too low. This was to a significant degree caused by the extraction of additional dividends by the government owner above a reasonable return, rather than the regulator providing insufficient funds.
- The owner of Dalrymple Bay port assets used its monopoly position and a tight market condition as leverage to force the regulator to increase the return on investment by refusing to invest at a time when there was an urgent need to increase capacity.