Northern Territory
Major Energy Users

Submission to AER

regarding

Application by NT Gas

for

New Gas Access Arrangement for Amadeus Gas Pipeline

February 2011

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission. The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

A condition by the Consumer Advocacy Panel for making funding available to the MEU to provide this submission is a requirement imposed on it by the Ministerial Council on Energy.

This requirement is that this submission must be considered to be a draft until the MCE has the opportunity to review it for accuracies of fact. The MCE review has been completed and there are no changes required to the NTMEU submission.

The NTMEU advises the AER that the NTMEU submission is unchanged and can now be made public and published in the AER website.

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EXECUTIVE SUMMARY

The AER must undertake this review with full knowledge that the Amadeus to Darwin pipeline was built to allow the development of the Amadeus Basin, and to provide Darwin with an alternative supply of thermal energy to that traditionally used in the Territory for power generation; including:

- The significant assistance that was provided by the NT government
- The recognition that gas supplies in the Amadeus Basin had a limited life, as would the pipeline
- Tariffs have accordingly been structured in recognition of the above two points
- Decisions by the previous regulator the ACCC, including on depreciation, the residual value of the leased pipeline assets in 2011, and the approved capex and opex allowances in the 2001 ACCC final decision and the reasons underpinning the ACCC's decision
- Discovery of new gas fields which has given a new impetus and life to the pipeline.

Because of the above factors, the AER must recognise that the pipeline assets now have a longer economic life as they can be used and are useful, but must not require consumers to pay twice for the assets that have in notional terms already been nearly fully depreciated.

In addition, there are concerns with the excessive claims for new capex and opex which are inconsistent with historical trends and these need to be carefully considered. The NTMEU have provided details of its concerns especially in areas where the claims appear to be unjustified, including the lack of transparency.

1. Introduction

1.1 About NTMEU

The Northern Territory Major Energy Users (NTMEU) welcomes the opportunity to provide comments on the application made by NT Gas to the AER for a new access arrangement, dated December 2010. The NTMEU is affiliated with the Major Energy Users Inc and its regional affiliates in SA, NSW and Victoria.

The NTMEU comprises the larger end users of electricity in the Northern Territory and includes the following companies: Northern Cement Limited, International Hotels Group, NT Airports, SkyCity, and BOC Limited. Some of the NTMEU members are direct users of gas in the region and others use gas indirectly as the electricity supplies in the Territory are essentially dependent on gas for its generation. Thus, gas supplies (cost and reliability) and their transport are integral elements to all electricity users.

The NTMEU has been established by the larger businesses operating in the Northern Territory. The members of NTMEU cover a range of industries: from manufacturing through to tourism. Member companies have identified that there are potentially more commercial options for providing essential services of gas supplies (and electricity) than currently apply in the Territory. As a result, the NTMEU has a great interest in the cost and availability of the monopoly elements of gas provision, such as gas transport.

The NTMEU recognizes the unique nature of the NT (its relatively small population and low population density, its large land area, and its remoteness from other Australian markets) but it considers that large amounts of gas available nearby and the closeness of northern (overseas) markets can provide a basis for a more competitive Northern Territory energy market, which in turn drive additional downstream investments and expand employment opportunities in the Territory.

NTMEU member companies' main objective is to promote access to long term, sustainable and competitively-priced energy (electricity and gas) supplies in the Northern Territory. We have identified a key interest in the **cost** of energy supplies (commodity, network services and transactions costs) as this represents a significant cost element in each member's business operations.

Although electricity and gas are essential sources of energy required by each member company in order to maintain operations, a failure in the supply of essential energy supplies will cause every business affected to cease production and/or suffer loss. Thus the **reliable supply** of energy is an essential requirement of each member's business operations.

With the introduction of highly sensitive equipment necessary to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important, with the need for a focus on the performance of the transport networks.

Each of the businesses represented in the NTMEU has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is paramount. If sustainable supplies of energy are not available into the future, investments made by energy users quickly lose their value.

Accordingly, the NTMEU has a keen interest in addressing issues that impact on the **cost, reliability, quality,** and the long term **sustainability** of member companies' electricity (and gas) supplies.

NTMEU comments are provided below on various elements of the NT Gas application for a new access arrangement for the gas pipeline connecting Darwin to the Amadeus Basin gas reserves and to the new connections to the ENI Gas Plant at Wadeye (the Bonaparte pipeline) and the Weddell Interconnect pipeline.

1.2 A consumer overview of the NT gas market

The Amadeus to Darwin pipeline was built in 1986 to allow the development of the Amadeus Basin and to provide Darwin with an alternative supply of thermal energy to the coal (and oil) that had been traditionally used in the Territory for power generation. As such it is an integral element of the Territory's development and as a result was significantly aided and supported by the NT government. Equally, the NT government recognized that the gas supplies in the Amadeus Basin had a limited life, and as a result the pipeline would have a similar life.

This means that the Amadeus pipeline should be considered to have a much shorter economic life than its probable technical life. To accommodate this it would be expected that the depreciation (return of the pipeline investment) would be recovered over a much shorter time than would be normally expected. At the time of building and setting of agreed tariffs for its use there was not considered to be an alternative source of gas and therefore it would be expected that the economic life of the pipeline would be the same as that of the proven and probable gas reserves in the Amadeus Basin. The amount of gas already recovered and the current rate of depletion means that the Amadeus reserves are now very low, implying that the remaining economic life of the pipeline is quite short.

In recent times, gas has been discovered and developed in the Blacktip and Bayu-Undan gas fields which are now delivering gas to Wadeye and Darwin respectively for converting the gas to LNG. Both of these resources augment the gas supplies to Darwin, but particularly the Blacktip field is connected to the Amadeus pipeline at Ban Ban Springs, some halfway distance between Darwin and Pine Creek. This means that as gas supplies from the south reduce, the requirement for backhaul from Ban Ban Springs south to Pine Creek and Katherine (and potentially further south to Mataranka, Macarthur River, Tenant Creek and Alice Springs), becomes the more normal flow direction.

1.3 Amadeus gas pipeline life cycle

The concern that consumers have is that as much of the Amadeus pipeline has been "paid back" in tariffs structured in the mid 1980s as it was expected the pipeline would have reached the end of its economic life (because there was no gas to transport from the exhausted Amadeus gas fields). However, the pipeline is about to receive a new lease of life due to the discovery and development of gas at the Darwin end meaning a reverse in flow is now inevitable. Thus an asset which is near to being fully depreciated but is used and useful, now has an extended technical life which was not expected when it was initially developed and the associated returns recovered.

This state of affairs presents the AER with a major challenge. Assets which have had a tariff structured to reflect an economic life much shorter than their technical life have reached near full depreciation while still being used and useful. This means that the regulatory asset base for the asset is very low but its useful life is still long. Under a building block approach, the bulk of the revenue is derived from the asset value (RAB) and the rate of return allowed (WACC) – embedded in the WACC is the return on equity which encompasses the profits a business makes. All other inputs to the building block are assessed at cost, so if the asset value is low then the regulated business receives a revenue based on its costs and very little profit, and it is profit that encourages a business to continue to provide a service. Thus, as the asset base approaches zero in value, even though the asset still is used and useful, the building block approach to regulation inevitably results in one of two outcomes:-

(1) The owner receives a greater recovery of the asset than it should (ie more than the full recovery of the initial investment – this is inequitable to users of the assets who pay more than is needed and is therefore economically inefficient, or

(2) The owner of the asset replaces the asset even though it is still useful – this is wasteful and economically inefficient.

As more and more assets approach the end of their economic lives but are still seen to be used and useful, this regulatory dilemma will become more of an issue.

1.4 An overview of the application

As is becoming the norm in relation to energy infrastructure applications for a regulatory reset, the applicants are seeking significant increases in opex and the WACC, well above the prevailing levels. Although transmission pipelines exhibit lower capex needs than do electricity transmission systems, the capex claim from NT Gas is significantly higher than it used in the past 10 year regulatory period. Again, as is typical, both capex and opex show a significant upward trend in the final years of the regulatory period.

There are also a number of key elements that the AER should be aware of when undertaking the review:-

- The total amount of gas that will be transported on the pipeline will only increase, although the amounts flowing on different parts of the pipeline will vary considerably over time

- The pipeline was built only after there were government backed commitments to haul gas on it, so the risk for the pipeline owner in relation to gas demand has been quite modest.

- The commitments made for the amount of haulage and the price for that haulage, were related to the expectation of gas supplies available from the Amadeus Basin. They were not dependent on new gas supplies coming from offshore, such as is now the case.

- Connections to the Darwin LNG plant and the Wadeye LNG plant increase the number of combinations of potential gas flows on AGP. This means that despite all firm capacity being contracted (especially northward flows contracted to PWC), there is potential for southward flows which are not contracted.

As the AER carries out its review, it is essential that these elements are kept in mind as the review progresses. Ultimately it is consumers of gas (and electricity) that have paid for the haulage of the gas on the Amadeus pipeline, and the bulk of the risks associated with it have been carried by consumers and NT tax payers. It would be totally inappropriate for the AER to require NT energy users to have to pay for this infrastructure asset more than once and deliver windfall profits to the asset owner.

1.5 The ACCC 2001 final decision on AGP

In 1999, NT Gas submitted an application to the ACCC regarding the AGP, as the pipeline is a covered pipeline under the Gas Law. In its application NT Gas advised that the AGP was effectively fully contracted and the ACCC review would have little impact on the revenue stream from the pipeline because the foundation contract did not expire until 2011, some 25 years after the pipeline was built.

The ACCC, it its final decision in 2001 acknowledges this and commented (page xii):

> "NT Gas does not anticipate that revenue will be generated by the sale of the Reference Service or negotiated service during the access arrangement period as the firm capacity of the ABDP is currently fully committed to users under pre-existing transportation contracts. As a consequence, this *Final Decision* is likely to have limited immediate impact for existing users.
>
> However, the *Final Decision* will be an important reference point for future negotiations on gas haulage services in the NT especially in the face of uncertainty concerning delivery of Timor Sea gas to Darwin."

The NTMEU recognizes that this statement has greater validity now because of the changed circumstances with the emergence of two new sources of gas and the decline of gas supplies from the Amadeus Basin.

The ACCC goes on to state (page xiv):

> "As the pipeline is fully contracted until 2011, it is unlikely that reference services will be sold in this access arrangement period. However, the forecast revenues resulting from the parameters proposed by the Commission would provide the service provider with the opportunity, if it were supplying the reference service, to earn a stream of revenue that would recover efficient costs associated with that service."

The NTMEU concurs with the concepts inherent in this ACCC observation, and considers that the AER needs to continue this policy. Because of this the NTMEU has responded to the NT Gas application as if the AER will do as the ACCC did in 2001 – i.e. there will be regulatory consistency and certainty.

2. The Asset Base, past capex and future capex

There are a number of concerns the NTMEU has with regard to the NT Gas submission and these concern the depreciation schedule used to establish the new asset base, the impact of past capex and the large rise in forecast capex.

2.1 Depreciation

In its final decision in 2001 the ACCC commented (page x) that:

Depreciation allowance	NT Gas proposes to depreciate the leased pipeline assets using accelerated depreciation to $61.84m in 2011 and standard straight line thereafter until the expiration of the asset's remaining technical life in 2066.	The *Final Decision* accepts NT Gas' arguments about future risks of stranding and proposes a depreciation schedule based on accelerated depreciation for the leased pipeline assets as proposed by NT Gas. This results in a residual value of $85.9m comprising both the leased and non-leased pipeline assets in 2011.

The ACCC also noted in its final decision (page xi) that:

> "NT Gas has submitted in its access arrangement information that the residual value of the leased pipeline assets on 1 July 2011 will be $61.84m. On the basis of evidence provided, the Commission is satisfied that $61.84m is an appropriate estimate of the residual value of the leased pipeline assets in 2011. In addition, the Commission has reason to believe that this estimated valuation was in existence in 1986. This view is supported by the uncertainty about the potential gas reserves in the Amadeus Basin."

The ACCC added (page xii)

> "The treatment of on-going depreciation has a significant influence on the revenue stream. NT Gas proposed accelerated depreciation of the initial capital base to reflect its concern about the sustainability of current levels of throughput over the life of the pipeline. It argued that there is significant uncertainty given the expiration of its foundation gas transportation contract in 2011, the lack of information on future production capacity of the Amadeus Basin and the potential for Timor Sea gas to enter the Northern Territory.
>
> The *Final Decision* accepts these arguments and that the leased pipeline assets be depreciated to a residual value of $61.84m in 2011. Those assets will then

> be depreciated on a standard straight-line basis over its remaining economic life (to 2066)."

The table 7.10 provided by NT Gas in its submission showing the development of the carry forward of the asset base, shows that the carried forward asset base is some $112m at June 2011. This includes a large element of capex in 2010/11 of $20.6m.

However, analysis of the actual capex compared to the allowed capex for the current period, shows that prior to the 2010/11 year, the actual capex used was well below the capex that the allowed revenue was based upon by over $5m. Further, whilst it is acknowledged that actual inflation of an annual 2.86% for the period was higher that the allowed inflation rate of 2.19%, this higher rate of inflation would have only added perhaps $5m to the asset base.

With the rate of depreciation set by the ACCC to achieve a carry forward of $86m, there appears to be insufficient depreciation included by NT Gas in the calculation of the asset base carried forward to incorporate the amount of depreciation that was included in the revenue allowed by the ACCC.

Effectively, the NTMEU is concerned that the amount of depreciation that the ACCC had included for NT Gas in the allowed revenue stream has not been fully included in the carry forward calculation of the asset base. The NTMEU is concerned that the requirements implicit in the ACCC decision have not been incorporated.

If the ACCC calculation of $86m is adjusted for actual inflation and the actual capex, then the NTMEU expects that the carry forward asset base would be $86m plus $5m for the actual inflation effect plus, at most, $13m overrun on capex[1], totalling $104m, whereas NT Gas is forecasting a carry forward of $112m.

[1] The NTMEU considers this is an "at most" figure because the underrun in capex in the first nine years was over $5m and the overrun is totally related to very high expected capex for 2010/11.

The NTMEU can only see that the differential is caused by NT Gas not using the depreciation rate set by the ACCC in its final decision.

2.2 Recovery of capital

Implicit in the Gas Code and the new Gas Rules, is the concept that costs for use of monopoly assets must be efficient as this results in the least cost to consumers over the long term.

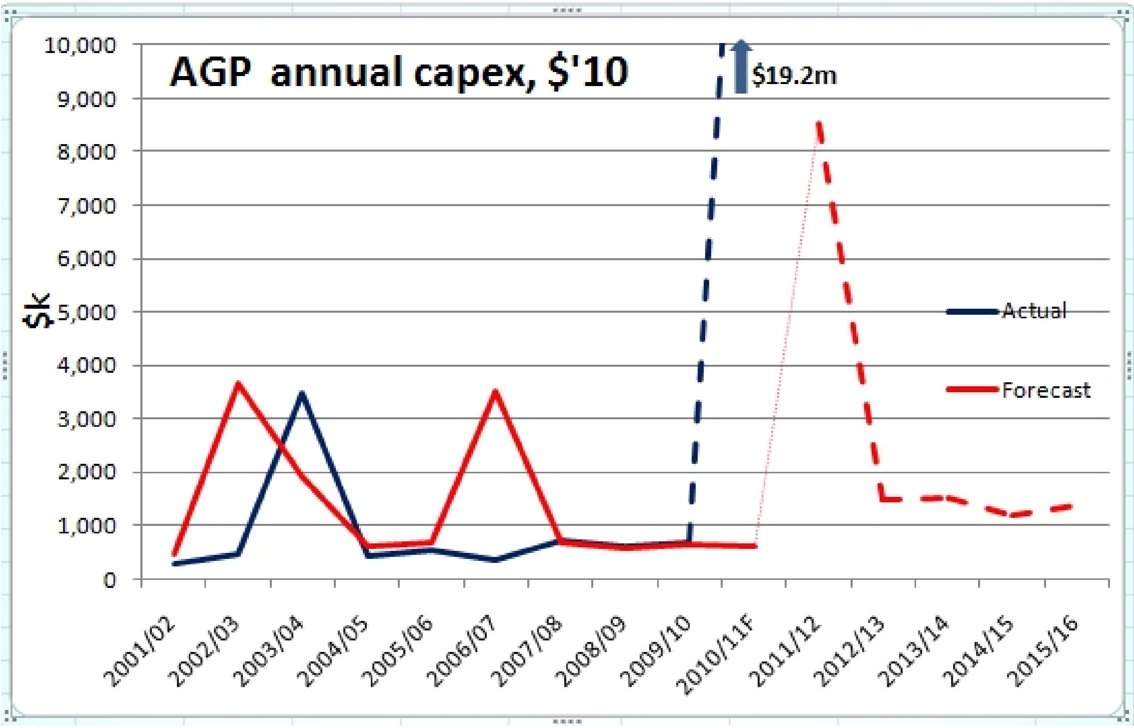
In relation to AGP, the pipeline has been effectively funded by a 25 year contract from a government owned entity (Power and Water Corporation - PWC). This government involvement has permitted the current financial structure of AGP to be established (ownership by a consortium of banks and leased to NT Gas). Such a financial structure would have required the bulk of the capital to be recovered in the period of the government backed 25 year contract, especially as the forecast of gas supplies from Amadeus Basin indicated (as has eventuated) that gas supplies would be limited from that source at the expiration of the foundation contract.

As the foundation contract was with PWC and therefore to supply gas for power generation, NT consumers have effectively paid this capital back to the initial providers of the capital. It is not efficient for a service provider to recover the capital more than once, so the AER needs to assess whether NT Gas has in fact, over the 25 years of the foundation contract, recovered all of the capital. It is insufficient to just accept the NT Gas assertions that it has not done so, because allowing NT Gas to recover more than the actual capital will provide it with windfall profits from a project that was fully underwritten by NT electricity consumers.

Notwithstanding the actual amount of capital recovered in the current period (augmented by the accelerated depreciation allowed by the ACCC), it is now quite clear that the services the AGP supplies will be needed for many years, because of the decision to source gas from Wadeye and inject this gas into AGP at Ban Ban Springs. This new source of gas has provided AGP with a new "lease of life" and so the depreciation rate of AGP needs to be adjusted to reflect that AGP will be "used and useful" for at least the 25 year period negotiated between NT Gas and PWC for supplies of gas to PWC facilities.

2.3 Historic capex

In its final decision the ACCC approved capex to be included into the allowed revenue stream of some \$11.8m or \$13.4 in current terms. This allowance along with the actual capital used by NT Gas and the forecast for capital needs into the next period, is shown in the following figure.



Source: NT Gas applic, ACCC FD

There are a number of conclusions that can be drawn from this figure regarding historic capex.

Firstly, is that prior to the current year 2010/11, NT Gas significantly under-run the allowed capex by some $5.2m in an allowance of $13.4m, ie that NT Gas utilised only 60% of its allowance of capex to that time. The benefit that NT Gas accrued because of that under-run was $2.8m based on the vanilla pre tax WACC of 9.1%.

The massive investment forecast for 2010/11 was not envisaged at the time of the reset review, but NT Gas advises that it is needed because of recently identified problems necessitating major replacement works. Even allowing for this very late investment, NT Gas still enjoys a net benefit between the allowed capex profile and its actual capex profile, of $1.6m.

Secondly, excluding the one off massive $19.2m expenditure in 2010/11, the average actual capex used was $0.8m pa and the average allowed capex was $1.3m pa. This clearly points out that without the large specific capex item, the underlying capex needs would be $0.8m. Thus, excluding the large specific capex items, the benchmark capex for setting the underlying capex for the next period should be $0.8m pa.

Capex forecast for the next period (excluding the one of large expenditure of $8.5m in 2011/12) averages $1.4m.

Thirdly, NT Gas has identified that there is a capex need of some $27.7m required to be spent over the two years 2010/11 ($19.2m) and 2011/12 ($8.5m). The bulk of this capex is for the “integrity works program” costing $17.3m (NT Gas provides details of 9 elements of this program – submission boxes 6.2 to 6.10) and the Katherine Meter Station upgrade costing $7.5m (submission box 6.1) but there is little detail provided for the other $2.9m included in the 2010/11 and 2011/12 capex program. In this regard, it is important to note that historically NT Gas has spent an average of $0.8m pa on capital works so, at best this still leaves some $1.3m of capex in this two year period unaccounted for.

2.4 The major works for 2010/11 and 2011/12

NT Gas has identified there is a need for relatively massive expenditure in 2010/11 and 2011/12 of some $27.7m. Of this NT Gas has provided details for $24.8m or 90% of the amount. These projects are:

- Katherine Meter Station Upgrade – Box 6.1
- Channel Island meter replacement - Box 6.2
- Channel Island Piggability Project - Box 6.3
- Replacement of Elliot heaters - Box 6.4
- Southbound piggability project - Box 6.5
- Cathodic protection upgrade stage 2 - Box 6.6
- Hazardous area assessment and equipment replacement - Box 6.7
- Palm Valley filtration and slam-shut - Box 6.8
- Heat Shrink sleeve replacement - Box 6.9
- Below ground station pipework recoating - Box 6.10

Unfortunately, NT Gas has not made the attachments to which they refer to in support of these projects available for review. Therefore NTMEU comments can only be general in nature.

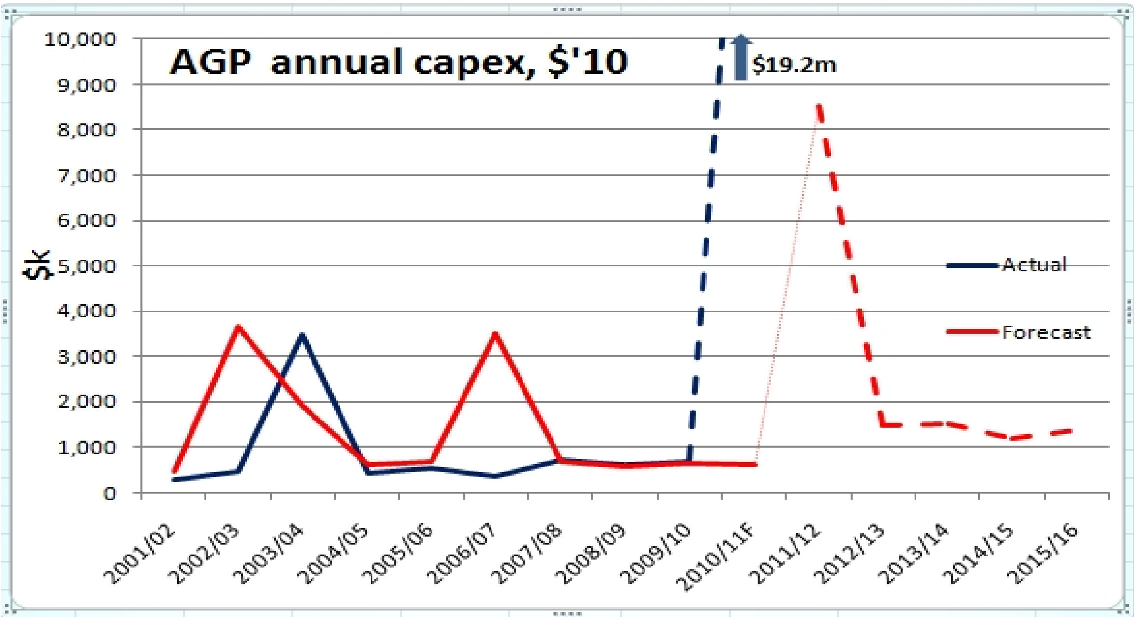
The NTMEU suggests that the AER not only examine the need for each project, but the costs involved and the timing suggested by NT Gas. It is quite apparent that even though NT Gas had significant amounts of unspent capex available for much of the current period, it seems incongruous that there is a sudden rush for expenditure as the current period finishes and the new one commences. Many of the projects have been required for a number of years (eg the Elliot heaters were needed in 2007 and the Channel Island meter station) yet NT Gas elected not to implement the projects at an earlier time. Other projects (such as the cathodic protection and coating replacement projects, and “Hazop” assessments and replacements) are ongoing work that should be continuously addressed and therefore would be in the regular annual capex works. In this regard it must be noted that the pipeline has been in operation for 25 years and therefore these issues would have been addressed on an ongoing basis.

It is accepted that some projects result from the potential changes in flow directions and closure of some injection points, and it is reasonable that such capex would be incurred when these changed conditions occur. However, NT Gas has previously not immediately implemented such projects and the question that NTMEU has is whether the timing is critical or whether some of the projects could be delayed or slowed down.

A cynical view of this capex program could be that NT Gas has maximised the revenue from not carrying out capex in the past, but as the foundation contract expires NT Gas has elected to "catch up" with delayed capex works just as the new contract with PWC is being established. Implementing this capex on the cusp of the new access arrangement to minimise the financial effect on it by carrying out a large capex program at the end of the access arrangement where the capex would quickly be rolled into the new access arrangement starting capital base and so immediately commence receiving a return on and of the capital involved.

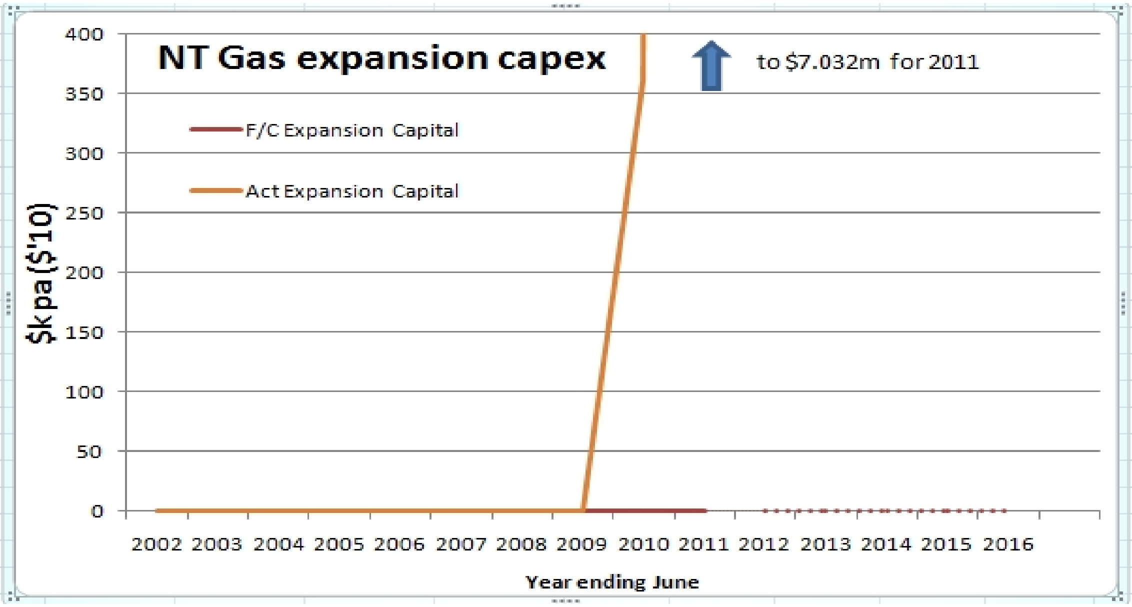
2.5 Future capex

Overall, excluding the relatively massive capex planned for 2010/11 and 2011/12, the forecast capex for the next period, is a significant rise from the underlying capex actually incurred for the past 10 years. This is shown in the following figure.

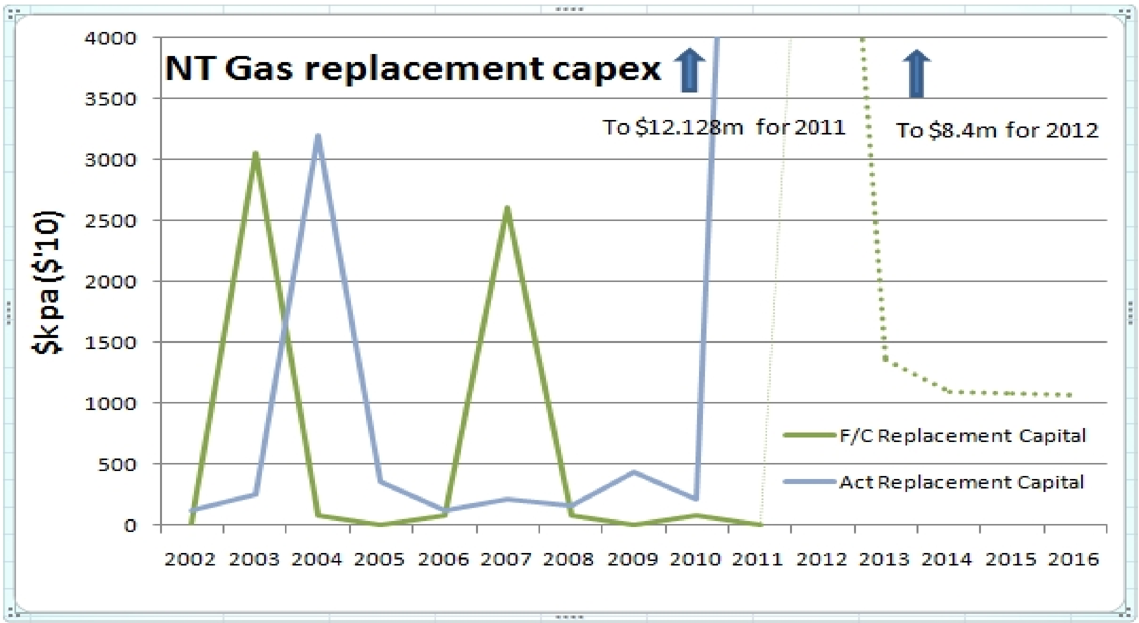


Source: NT Gas applic, ACCC FD

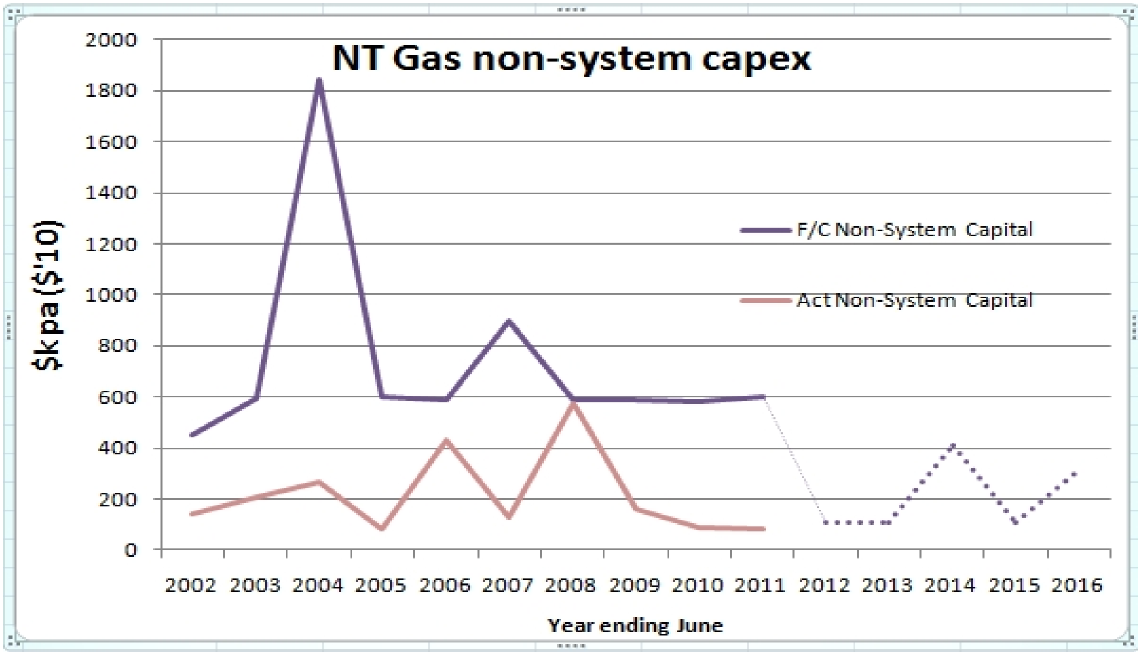
Basically the forecast underlying capex is twice the actual underlying capex. Analysing the capex into the three main categories (expansion capex, replacement capex and non-system capex) clarifies where the increase is. The following three figures show the capex for each category.



Source: NT Gas applic, ACCC FD



Source: NT Gas applic, ACCC FD



Source: NT Gas applic, ACCC FD

Clearly, excluding the relatively massive capex in 2010/11 and 2011/12, the underlying expansion capex is zero as is the forecast expansion capex. The forecast non-system capex of $0.21k pa for the next period reflects the actual capex incurred in the current period of $0.22k pa. Thus there appears to be some consistency in these two forecasts

The replacement capex in the current period (excluding the 2010/11 and 2011/12 period capex) exhibits an underlying capex need of $560k pa, yet the forecast for the next period exhibits an underlying capex need of over twice this at $1,150k pa. There is no explanation for this underlying capex to show such an increase, and the AER should examine the claims very closely.

Overall, the forecast capex (including the forecast for 2010/11) needs a very close review, especially that for 2010/11 and 2011/12, as well as the step doubling of replacement capex for the next period. It would appear that NT Gas has under-run capex allowances in the past, so great care needs to be applied to ensure that all of the forecast capex is necessary and will be used.

2.6 Escalation of costs

NT Gas has escalated its forecast costs from a 2010 base rate by adding a real labour escalator of 1.5%. It is not clear from the submission how this actual value is determined or to what it applies. What is important is that the Access Economics report to which NT Gas refers shows that privately employed staff experience a lower rate of increase than public employees, whereas the NT Gas submission uses the average of all employees.

Wage Price Index (hourly rates of pay excluding bonuses, original)

	September Quarter		change		
	quarter	year average	quarterly[1]	annual[2]	year on year[3]
Northern Territory	**105.9**	**104.4**	**1.2%**	**3.9%**	**3.4%**
public	106.4	105.4	0.9%	4.1%	4.4%
private	105.5	103.7	1.4%	3.7%	2.8%
Australia	**105.7**	**104.1**	**1.4%**	**3.6%**	**3.2%**
public	106.9	105.3	1.4%	4.0%	4.1%
private	105.4	103.7	1.5%	3.5%	2.9%

Source: Wage Price Index & Average Weekly Earnings September Qtr 2010 Access Economics for NT Government, released 18 November 2010

The AER needs to assess the legitimacy of the NT Gas assumptions and how these have been applied to the forecasts of capex and opex.

With regard to the impact of escalation changes for materials, NT Gas has advised that these are included in their forecasts as the changes in the market in the NT for materials is difficult to assess. The NTMEU is aware of the difficulties of operating in the Territory, but the challenges faced by NT Gas are not unique. The AER needs to assess very carefully the claims by NT Gas as the potential for NT Gas to significantly overstate future materials costs is large. In this regard, the NTMEU points out that prior to 2010, the forecast capex allowances made in 2001, were significantly overstated and as a result provided NT Gas with a considerable benefit (see section 2.3 above).

3. Operating Expense (opex)

In the 2001 revenue reset review, the ACCC accepted the opex forecast by NT Gas as efficient. In its decision in 2001, the ACCC benchmarked the opex costs and observed (pages 99 and 100):

"3.5.5 Commission's consideration [of the opex claimed by NT Gas]
Two industry accepted benchmarks for operations and maintenance costs are cost per pipeline length and cost per volume transmitted. Comparisons between the ABDP and other transmission pipelines in Australia are shown in Table 3.8 below. In terms of $/1 000km, the ABDP compares favourably with the other pipelines. However, in terms of $/GJ, the ABDP appears to be more expensive to operate than other pipelines.

It must be noted that while these measures of pipeline cost efficiency have been accepted in the industry, they do have limitations. The comparisons can be made, but in doing so other aspects of the pipelines such as compression, age and throughput should generally be noted.

Table 3.8: Comparison of transmission pipeline non-capital costs

	$/1 000km ($m)	$/GJ
NT Gas – ABDP (2001)	4.1[c]	0.42[d]
EAPL – MSP (2001)[a]	6.1	0.12
Epic – Moomba-Adelaide Pipeline (1999)[b]	19.2	0.16
TPA – Victorian transmission systems (1998)	16.0	0.13
AGLP – CWP (1999)[e]	2.8	2.62
AGLP – CWP (2004)[e]	2.8	0.52

Notes: (a) EAPL, Proposed Access Arrangement Information, p. 65.
(b) Epic, Proposed Access Arrangement Information, attachments 1 & 4.
(c) Based on total operating costs for 2001/02 ($6.8m) divided by pipeline length (1649km).
(d) Total operating costs for 2001/2002 divided by total throughput (16.4PJ).
(e) AGLP, Revised Access Arrangement Information, pp. 27-31. 2004 figures based on forecast throughputs.

The higher $/GJ measure calculated for NT Gas may be attributed to the differences in capacity/throughput between the pipelines and the subsequent economies of scales inherent in larger capacity pipelines. For example, while

> both the ABDP and MAPS are fully contracted, the current firm capacity for each of the pipelines is approximately 54 TJ and 323 TJ per day respectively.
>
> Another measure that is sometimes employed is to determine forecast operating costs as a percentage of the overall capital assets employed. Typically, results range from 2 per cent for an uncompressed pipeline to 5 per cent for a fully compressed pipeline. In NT Gas' case, forecast operating costs are approximately 1.8 per cent of the ORC value calculated by the Commission. On this measure, the Commission considers NT Gas' forecast costs to be reasonable, as did NTPG. The Commission notes PWC's comments regarding NT Gas' cost of delivering services.
>
> The Commission is of the view that the proposed non-capital costs are not unreasonable and are not contrary to the interests of users and potential users under section 2.24(f) of the Code. The Commission has considered whether the proposed non-capital costs represent the legitimate business interests of the service provider and are necessary for the safe and reliable operation of the ABDP under sections 2.24(a) and (c) of the Code.
>
> The Commission is also of the view that the revised operating costs (as per Table 3.7) satisfy the requirements of section 2.24(d) of the Code. Chapter 5 of this *Final Decision* discusses the use of KPIs and performance benchmarks in more detail. It concludes that, on the basis of the available information and KPIs, the operating, maintenance and other non-capital costs for the ABDP are not unreasonable."

This means that the total opex claimed by NT Gas in the 1999 to 2001 period is seen as efficient and therefore other conclusions can be deduced from this view.

Because of this, in the following analyses, the amount of opex forecast by NT Gas is the same as the amount of opex the ACCC allowed in the reset. Rather than show two identical figures (forecast and allowed), the following work just shows the amounts forecast by NT Gas during the 2001 reset review.

In its final decision the ACCC also made the observation (page 162) that:

> "... arrangements whereby NT Gas has contracted activities out to other companies in the AGL Group create particular difficulties when using of some of the benchmarks mentioned above. As NT Gas has no employees, 'per

> employee' measures are not directly available. Further, to the extent these contracted entities are primarily engaged in activities unrelated to the ABDP, there may be factors such as economies of scale and scope that blur comparisons with pipelines that would on face value appear to be comparable with the ABDP (for example, stand-alone pipelines of similar diameter and length)."

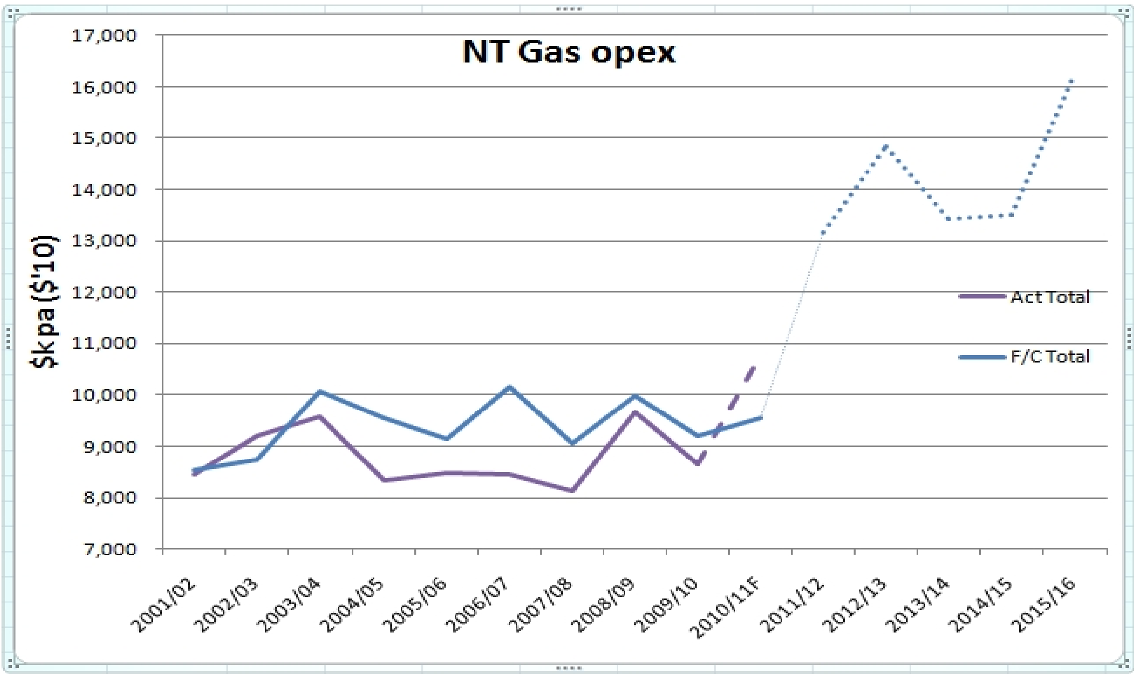
The purpose for making this observation was that setting appropriate benchmark performance criteria was made difficult by the unique structure that NT gas has. However, subsequent decisions by the ACCC, and later by the AER, in regard to regulating gas transmission and distribution systems, the regulator has determined that regardless of the structure used by the regulated entity, the regulator needs to assess the legitimate costs as if the regulated entity was directly responsible for the works, even though it might have contracted the activities out in order to reach efficient costs.

Therefore this reset review needs to be carried out in a like manner, as if NT Gas was directly responsible for the activities. Efficient costs are therefore those costs which NT Gas has demonstrated are efficient in delivering the services it has contracted for. Its historic actual costs are considered to be guide as to what future efficient costs might be.

3.1 Overview of past opex

As with capex, NT Gas underspent the allowances provided by the ACCC for opex. As the ACCC allowances were the same as the NT Gas claims for opex, it therefore can be deduced that NT Gas actually spent less opex than it itself had forecast.

Overall, NT Gas had an average actual opex of $9m pa although if the forecast for 2010/11 is excluded, the underlying opex is closer to $8.8m pa. There has to be some concern about the 2010/11 forecast opex, as it shows a significant rise of over 20% above the long term opex trend. This is shown graphically in the following figure.



Source: NT Gas applic, ACCC FD

As with capex, NT Gas significantly under-run the expected allowances and its own forecasts. Again, excluding the forecast for 2010/11, the average actual opex was $8.8m pa and the average forecast opex for the same period was $9.4m pa, an average under-run of over $0.6m pa, which over the nine year period equates to some $6m[2] or some $0.7m pa. Even though NT Gas opines that the under-run is a "minor deviation" to its overall opex, the under-run is still a significant benefit to NT Gas profitability because any saving such as this is an immediate contribution to the company profits. NT Gas attributes the savings to better operations practices, less overhead and lower expenditure on sales and marketing.

What is important about the opex under-run is that NT Gas not only earned an unexpected profit from its opex, but by doing so it set a benchmark performance for itself of a total annual opex need of $8.8m. For the sake of comparison the actual opex

[2] NT Gas states that the total under-run for the period is $4.8m. As the over-run of opex in 2010/11 is some $1.2m, this implies that the under-run for the first 9 years is $6m

in the final full year of operation was $8.66m, lending credence to what the long term opex needs of the system are.

In this regard, it is important to note that NT Gas operations have not been impacted by any scale increase as there has been little no expansion of the operations since it was first built in the mid 1980s, and virtually none (other than the Katherine meter station upgrade) since the last reset review in 2001. For the sake of benchmarking opex performance, it needs to be highlighted that although the Katherine meter station upgrade has been classified by NT Gas as an expansion project, in practical terms, it is a replacement project in that an existing meter station is being replaced with a higher capacity meter station. This means that effectively there will be little impact on the opex needs associated with this "expansion" project.

The NTMEU is aware that there is no ability of the AER to "clawback" the profit generated by NT Gas as a result of its under-run, but the AER is required to recognise that the actual historic opex should provide the basis for setting future opex.

NT Gas notes that some of the savings they had against their opex budget were attributable to work practices they used to drive costs down. This resulted in a higher than expected turnover of staff and labour and that currently NT Gas had a number of unfilled positions. What NT Gas does not state is that its staff practices are not unique to it, and apply equally to other employers in the region. Balancing costs against staff turnover is an ongoing challenge in the Territory and how well an employer manages this is a mark of its efficiency. Therefore NTMEU points out that the AER must address the opex performance of NT Gas on its historical outcomes, and not permit the NT Gas assertions of the difficult environment it faces in the Territory, to otherwise cloud a rational assessment.

3.1 Step changes to "base year" opex costs

In recent years the AER has reviewed opex on the basis that the actual opex incurred in the last full year of operation will be used as the "base line" opex and step changes that are not included in this amount will be added to the base line opex to set a revised baseline for the forecast opex needs.

Unfortunately, the Attachment I – operating expenditure base year adjustments and step changes, is marked confidential and is not available for public review so the NTMEU is not able to address the aspects raised by NT Gas specifically. However, the decision of NT Gas to withhold this document from public scrutiny needs to be assessed.

As NT Gas operates a monopoly, by definition, it has no competitors. Therefore, prima facie, there is no need to withhold any information regarding the operations of the monopoly assets. In fact, there is a rational argument that would require this information to be disclosed so that there is no doubt that the provider of the monopoly service is only seeking the efficient costs to provide the service. The AER should assess whether the exclusion from public view of these step changes is driven by a need to protect NT Gas from its competitors or to conceal information which might be detrimental if seen in a wider forum. NT Gas advises that it is part of the APA group. The APA group is by far the dominant provider of gas transmission services in Australia. The NTMEU therefore queries what it is that is so secret about the step changes that the dominant provider of such services needs to have concealed.

NT Gas points out that there a number of aspects applying to the 2009/10 (the "base year") that need to be adjusted to reflect the step changes that need to be accommodated in the future.

3.1.1 Base year anomalies

NT Gas advises that its base year costs were lower than normal due to the redeployment of staff to the Bonaparte Gas Pipeline and the Weddell Pipeline (both non-regulated activities). If staff can be redeployed for such significant periods so as to artificially reduce the opex, then it raises the question as to whether such staff are needed in relation to the regulated services.

The fact that the base year opex is much the same as the long term opex tends to support the NTMEU view that the absence of the staff on these two non-regulated activities should not be the basis for an increase in the base year opex, and therefore is not a step change.

Further, as NT Gas has already used staff allocated to the regulated activities for non-regulated activities, the NTMEU is concerned that NT Gas has the opportunity to continue to use this practice and so generate benefits for its non-regulated activities. The AER must address this issue to ensure that the practice is clearly ring fenced.

3.1.2 Increased integrity works

NT Gas advises that a step change is the increased number of dig-ups to repair pipeline coatings. What is not clear is why more dig-ups are required than in the past, especially considering that the capex program has been massively increased in order to address the suspected breakdowns of the pipeline coatings.

Corrosion of steel pipelines is not a recently discovered phenomenon, but one that exists continuously over a pipeline's life. Corrosion does not just suddenly appear at the halfway mark of a pipeline's life – it is an issue that needs constant attention from the beginning when the pipeline is new. The NTMEU is not convinced this is a step change, but is a continuous activity that has been addressed within the past opex.

This issue also provides a good example of where capex should result in less opex, yet NT Gas is advising that not only does it need more capex to address the problem, but that opex has to increase as well. This appears to be inconsistent, especially as the historic opex and capex would appear to have prevented the need for such drastic activity for the past 25 years.

If the massive capex injection for the integrity projects can be sustained, then the AER needs to assessed very carefully, why there is an expectation of more frequent coating breakdowns at the same time. The NTMEU considers that the capex program can only be demonstrated as efficient if it concurrently reduces the need for opex, especially the increases in opex forecast by NT Gas.

3.1.3 Cathodic Protection Surveys

NT Gas asserts that the new helicopter costs are greater than the previously used helicopter which can no longer carry the survey equipment used. NT Gas has not provided any details nor whether it would be more efficient to use lighter survey equipment than to use a larger helicopter.

The question also arises whether the costs for the new helicopter are being properly shared with costs for non-regulated pipelines.

3.1.4 Access fees

As the pipeline has not increased in size, it seems strange that access fees would increase. The NTMEU considers that great care should be used in assessing whether this is indeed a step change, or whether it is related to the expectation that increased flows will result from changing the direction of gas flows. If the expectation is that NT Gas will increase its revenue as a result of the flow change pattern, then this assertion makes sense. However, if this is the reason, then the increased cost in fees needs to be amortized over the greater volumes of gas transferred – both regulated and unregulated.

3.1.5 SCADA costs

NT Gas points out that the addition of one more supply point (at Ban Ban Springs) will result in increased ongoing SCADA operations. NT Gas has claimed that it needs to some $1.4m in capex for SCADA and Communications. This indicates that the capex allows for the increases in costs to accommodate the additional injection point.

Whilst the NTMEU can accept that the addition of one new supply point might cause an increase in the capex to accommodate it, it finds it difficult to accept that this will impact the long term daily O&M charges.

3.1.6 Emergency response trucks

NT Gas had previously allowed for the capex needed to replace the emergency response trucks that are quite elderly. By not replacing these trucks under the capex program, NT Gas made a windfall profit by not expending the capital allocated for this purpose. It is able to retain the benefit of this under-run in capex.

Now NT Gas is seeking an increase in opex as it proposes to finance lease the vehicles rather than acquiring them. Providing there is no double up (claiming both capex and opex for these trucks) then this might be considered a step change.

However, the NTMEU is concerned that overall, NT Gas has orchestrated an overall benefit for itself by the deferral of the approved capex but then adding the related cost as opex in the new arrangement. This supports the NTMEU contention that the AER must take careful note of the underlying capex and opex so that unearned benefits as NT Gas is getting, are reflected in the benchmark settings of capex and opex.

3.1.7 Non annual expenditure

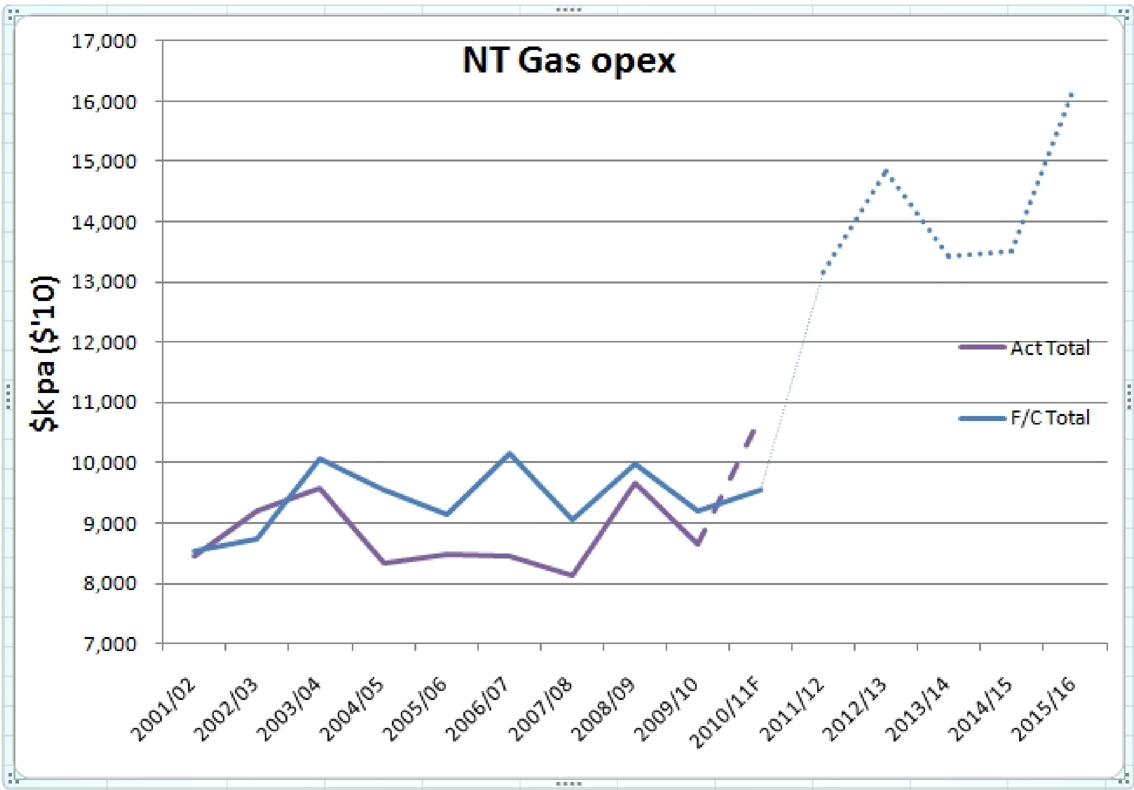
NT Gas has forecast as step changes “right of way erosion, more frequent pigging, recoating of above ground pipework, and battery replacement. NT Gas advises that due to the non-annual nature of the activities, these regular costs were not included in the base year opex.

The NTMEU recognises that if more frequent pigging is required than this is a step change, and the costs be amortised over a shorter period. However, it must be stated that pigging is not new in itself, only that it is to be more frequent. Therefore only the amortisation impact (ie 10/7 times increases in annual allowance for pigging costs) should be seen as a step change.

The NTMEU considers that the long term opex already includes for the repair of erosion, repainting and replacement of batteries. As NT Gas enjoyed lower opex costs for most of the past decade than it was allowed, then the AER must recognise that the long term opex must be seen as a benchmark, rather than just relying on the opex for just one year, especially when NT Gas has an incentive to defer opex costs from earlier years and inflate the costs in the “base year”.

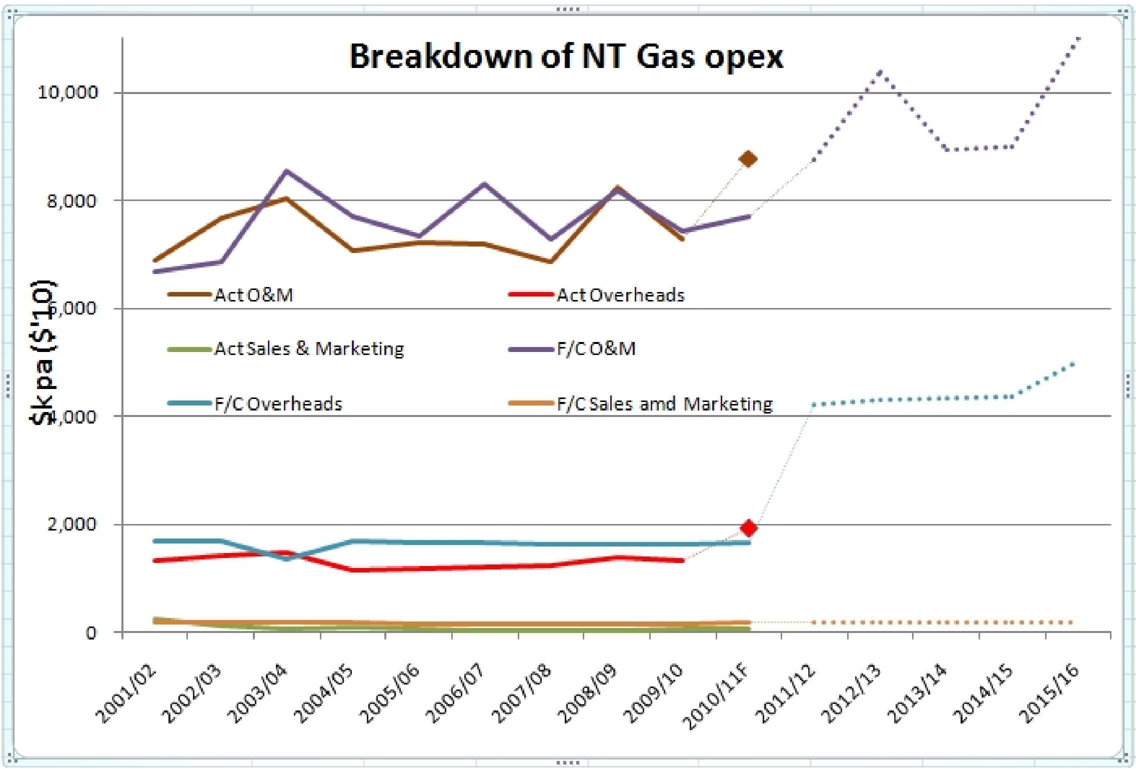
3.2 Forecast opex

Overall, NT Gas is forecasting that its opex will increase from an historic average of some $9m pa to a new average cost of $14.2m pa, an increase of nearly 60%. At a visceral level, this increase is totally unacceptable and unsustainable – this increase is clearly shown in the following figure.



Source: NT Gas applic, ACCC FD

Because of the magnitude of the increase, it is important to examine the three basic elements leading to this massive increase in costs. The following graph breaks down the forecast opex into operating and maintenance, overheads and sales and marketing.



Source: NT Gas applic, ACCC FD

A break down into the three main elements shows that there is a large step increase from the long term average in each of the three elements – a 28% increase in O&M, a 225% increase in overheads and a 100% increase in sales and marketing.

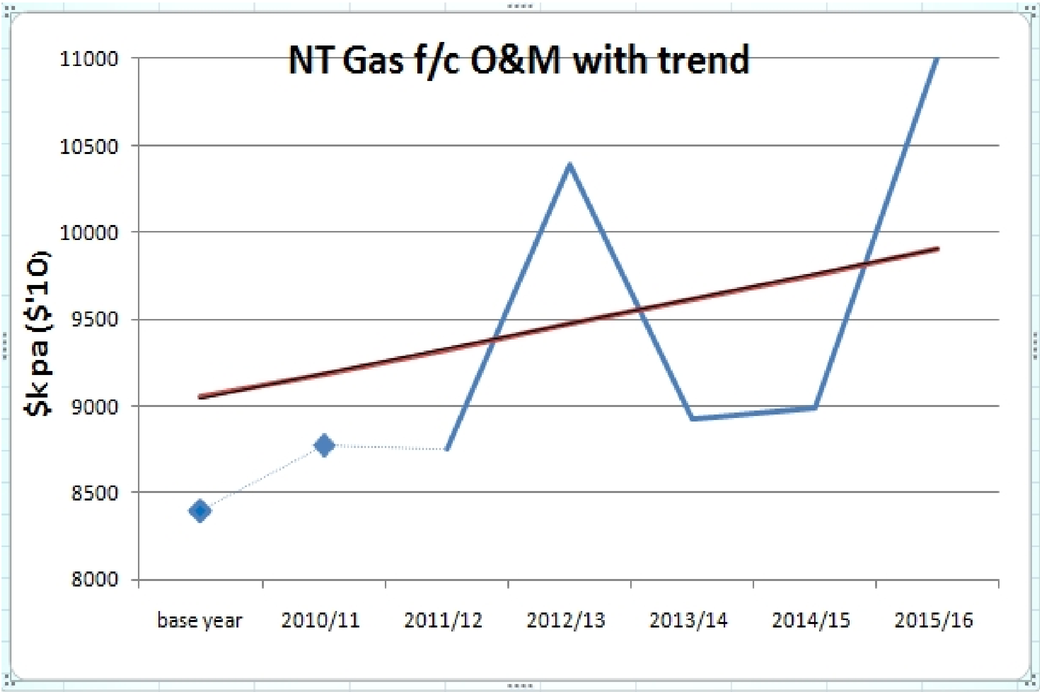
In addition, there is a step increase from the long term average in the forecasts for 2010/11 for O&M of 17% and overheads of 40% which combined lead to 2010/11 forecasts showing an increase from the long term average opex of 20% - ie that 2010/11 opex is 20% higher than the long term average opex for the past decade.

The NTMEU considers that these increases are not reasonable or sustainable, and the AER needs to address them in detail.

3.2.1 Operating and maintenance (O&M)

NT Gas states that the forecast opex is based on step adjustments to the base year opex. The NTMEU comments regarding the base year O&M and step changes are included in section 3.1 above. Unfortunately NT Gas has withheld the details associated with the specific step changes which it considers are appropriate but they do advise that the adjusted base year O&M is $8.4m pa (see table 9.1) an increase of $1.1m or 15%.

The following figure provides the forecast O&M with the NT Gas assumed base year costs and a trend line based on an assumed 1.5% pa growth in O&M costs annually[3].



Source: NT Gas applic, NTMEU calculations

Although the NTMEU is unconvinced that forecast opex will increase at an annual rate as is shown in the figure above, the analysis was carried out to

[3] In the absence of any better information, the NTMEU has assumed that because NT Gas has provided an argument that labour costs will escalate at 1.5% real.

provide an indication as to the legitimacy of the forecast O&M relative to the base year costs calculated by NT Gas. This analysis shows that even supposing the base year cost adjustment provided by NT Gas is correct (which the NTMEU does not), then there is still a major discrepancy of some $0.7m pa (or nearly 10%) between the forecast O&M needs and the adjusted base year annual cost. Even the 2010/11 forecast O&M is below the trend line, adding to the NTMEU concerns.

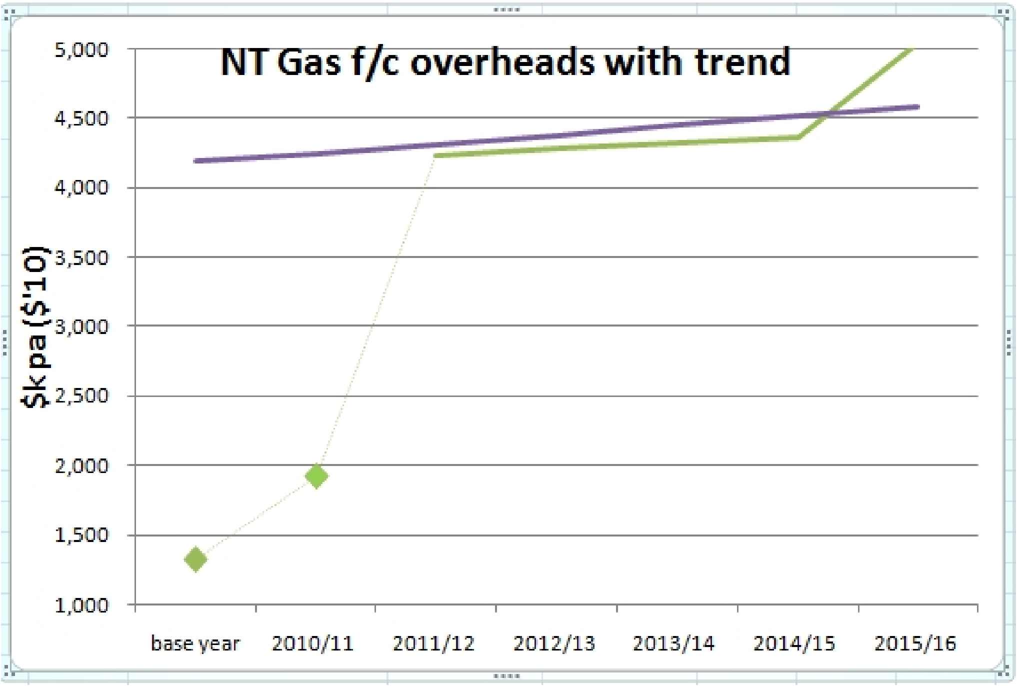
NT Gas offers no explanation as to why the forecast opex for the next period should be so much higher than its base year costs.

Overall, the NTMEU considers that the base year costs as calculated by NT Gas are probably too high, but after including the costs associated with pigging on a cycle of 7 years rather than every 10 years (which increases the pigging costs by ~50%) a reasonable O&M allowance as a base year might be $7.7m pa rather than $8.4m pa sought by NT gas. Adding this differential to the unsubstantiated additional $0.7m pa identified in the paragraph above implies that NT Gas has overstated its O&M costs by some $1.4m pa or by 20%.

3.2.2 Overheads

NT Gas has advised that it has split its overheads into four categories – local overheads, corporate overheads, insurance and regulatory costs. Of these NT Gas states that the only element of overheads that is related to a base year is the local overheads. The other elements of overhead costs are calculated from a zero base as if they are new costs.

The following figure shows the actual overhead costs (labelled Administration and General – A&G – in the ACCC 2001 FD) incurred in the current period. As there is no other category of costs included elsewhere, the A&G allowance includes local overhead, corporate overhead, insurance and regulatory costs.

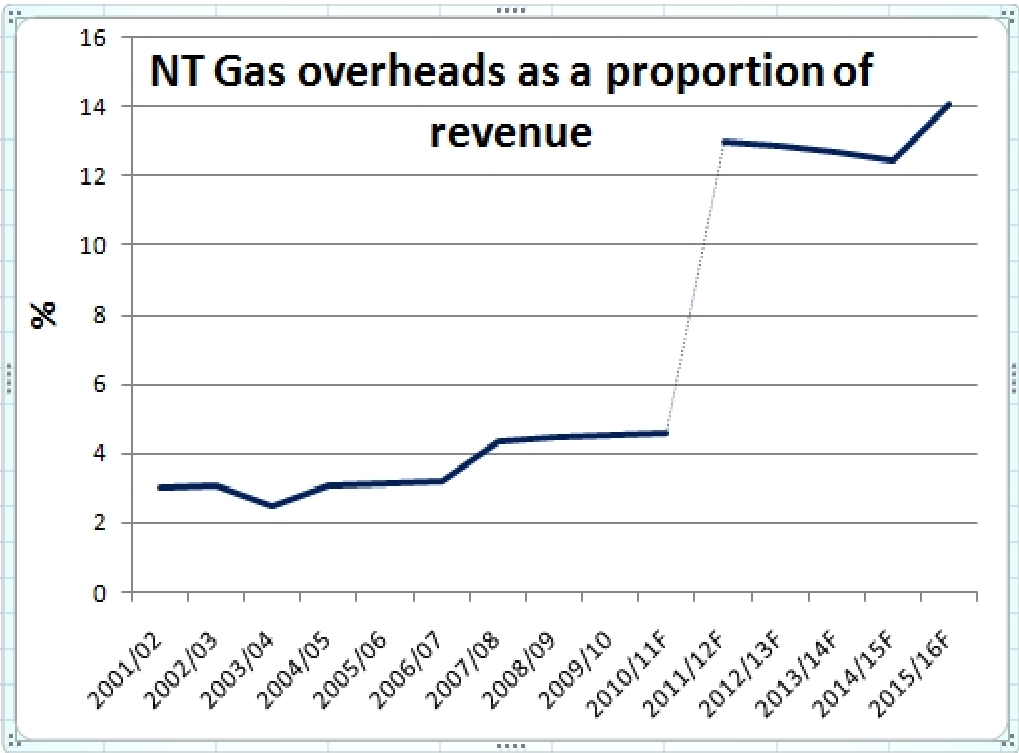


Source: NT Gas applic, NTMEU calculations

Overall, NT Gas sees that it should be able to recover an additional $3m pa for overheads that it states will now be incurred as a result of its provision of the gas transport service. That such costs were not incurred in the current period raises the question as to why they are now a cost that NT Gas must incur as a result of its service provision.

The NTMEU recognises that overheads are incurred in the provision of an activity. During the current period, NT Gas sought and was granted overhead costs that were in the range of 3-4.5% as shown in the following figure. The step rise in 2007/08 is attributable to the large reduction in revenue that resulted from a significant fall in allowed revenue caused by the changed depreciation schedule after 2007. The changed depreciation schedule was a result of a change to a lower rate of recovery of capital than in the earlier years where accelerated depreciation was allowed.

The revenue sought by NT gas for the next period is much the same as the revenue allowed for the past four years, so there is an expectation that the overheads for the next five years would be a similar percentage of the total revenue, reflecting that the same depreciation rate will be maintained.



Source: NT Gas applic, ACCC FD

In fact, NT Gas overheads have risen to 13-14% of revenue which is a three to four fold increase from the current rate of overhead recovery. Whilst it is recognised that as the asset value reduces over time (with an associated fall in return on capital) it is expected that the proportion of overhead (and all opex) would slowly increase as a proportion of revenue (as has occurred in the current period), this does not explain the large step change that NT Gas has claimed for its increased overhead.

Prima facie, this increase is unsustainable and the following sections analyse individual elements of the causes detailed for the increase.

3.2.2.1 Regulatory costs

In the 2001 review, NT Gas was aware that in years 2009/10 and 2010/11 it would undergo a regulatory review. The ACCC was also aware of this. However, different to the current review where NT Gas has added $646k in year 2015/16 to address the next regulatory review, NT Gas in 2001 must have elected to amortise this cost over the entire regulatory period (as have many other regulated entities) as there is no large rise at the end of the period. Therefore the current A&G allowance includes a proportion of regulatory review costs although the current actual costs (the base year costs) would exclude the regulatory review costs. On this basis the NT gas approach to regulatory costs is reasonable, although the actual amount claimed appears to be quite high and should be investigated by the AER.

3.2.2.2 Local overhead.

NT Gas advises that its local overhead cost is $805,000 pa and that this is derived from the actual overheads incurred in the current period. The overhead incurred in the base year is $1,318,000, so presumably the balance of $513,000 comprises other costs such as insurance and corporate overheads. As NT Gas provides no detail as to how it has derived the $805k pa for local overhead from the actual overhead incurred for the base year, the NTMEU can offer no observations as to its legitimacy.

The AER should require NT gas to demonstrate that its assessment for local overheads is supported by the actual costs incurred for the local overhead.

3.2.2.3 Insurance costs

NT Gas has included some $1.261m pa for insurance costs. However the base year costs would have included some insurance costs already.

As there is only $513k pa of the base year overhead remaining after deducting $805k for local overhead, presumably either this amount was for insurance and corporate overhead. AS the claimed insurance is $1.261m pa, there appears to be a massive (more than double) increase in insurance premiums.

NT Gas makes no observation as to what the insurance amount covers, nor to what extent the insurance costs have risen above the amount already included in the base year overheads costs.

In its 2001 FD (page 94) observed that:

> "Many risks [related to the NT Gas claim for a premium=m in the WACC for self insurance costs] of the nature described by NT Gas are insurable and are captured as insurance premiums forming part of the operating and maintenance cost of the business."

This confirms that the ACCC considers that the overhead costs already include an amount for the cost for insurable risks.

Therefore the approach used by NT Gas in relation to a zero base for insurance costs is flawed and the amount claimed must be reduced by the amount NT Gas has been paying for insurance that is already part of its actual overheads expenditure.

The AER should also gain confirmation that the new amount or $1.2m pa for insurance is a legitimate expenditure.

3.2.2.4 Corporate overhead

NT Gas advises that it is entitled under Rule 93 to recover its costs involved in providing the service. The NTMEU concurs with this concept, but the NT Gas submission goes much further and seeks to add a new cost into the overheads.

As detailed above, local overheads and insurance (with some allowance for amortised regulatory costs) currently totals \$1.3m which is the actual overheads in the base year. Combining the new insurance cost of \$1.261m pa with the local overhead of \$0.805m pa and amortising the regulatory costs of \$0.646 m (to \$130m pa) increases the overheads to \$2.196m pa, which is an increase from the base year overheads of \$1.318m or a 66% increase.

Even if this step increase can be justified (which NTMEU doubts) then there is no explanation as to why there should be another increase to accommodate corporate overheads.

The inclusion of corporate overheads means one of two things – either NT Gas did not include these costs in its previous application (which was assessed by the ACCC as being reasonable) or NT Gas proposes to use much more of the corporate services than it used in the current period. In the latter case, NT Gas is also forecasting an increase in the other cost elements so it appears that this is not the case.

NT Gas justifies its inclusion of the large corporate overhead by stating shared costs need to be allocated in a reasonable manner. The NTMEU does not disagree with the concept but sees that if the current overheads incorporate corporate overheads, then these would reflect the needs of NT Gas for corporate support.

In this regard it must be recognised that NT Gas has been entirely controlled by APA Group since APA Group was floated in mid 2000. Prior to that NT Gas was controlled by AGL which floated APA from AGL gas transmission pipeline assets. Essentially NT Gas has been under the same or similar ownership control for the entire period since the first regulatory decision was completed in 2001. During that time, NT Gas had considerable scope to change its application for the current period along with its revenue claims[4].

If the allowances for corporate overhead in the current period are considered to be inadequate, then this is a major change from the corporate view that applied when the current access arrangement was established.

If the corporate overheads in 2001 were considered to be appropriately recovered from NT Gas at that time, then the same rate of corporate overhead should be applicable now.

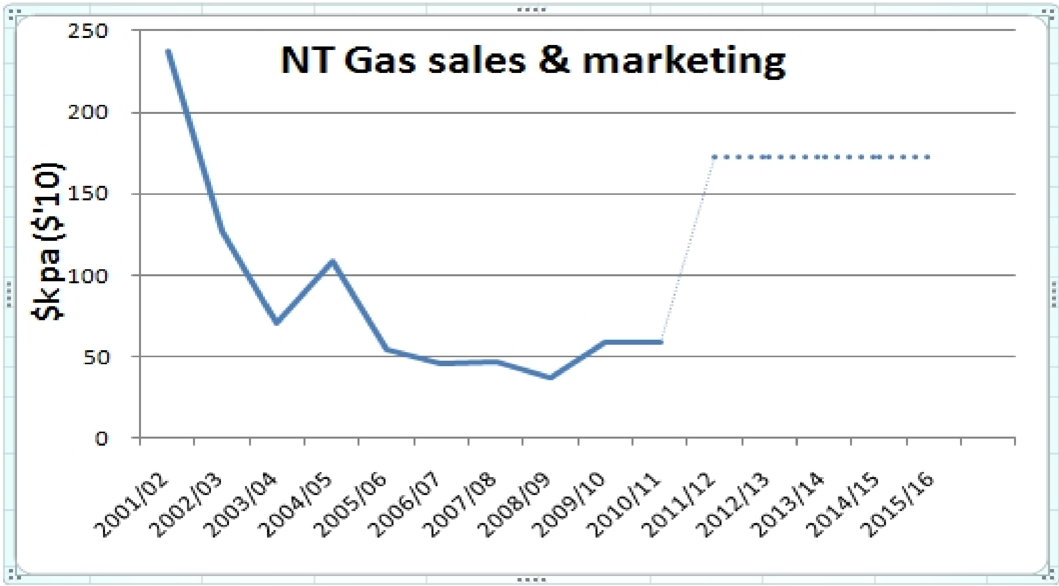
Analysis of the step increase in opex, shows that the biggest single contributor to the increase is the higher corporate overhead. However, other than state that corporate overheads should be allocated equitably, NT Gas provides no explanation as to why there has been such a large increase in its share, not do they provide an indication as to the greater value to users of the pipeline services get than the users do under the current corporate sharing arrangement.

3.2.3 Sales and Marketing (S&M)

Although the amounts included for sales and marketing are quite modest, they still demonstrate an increase of more than 100% above current actual costs.

[4] This is particularly notable in that in its application in June 1999, NT Gas sought a 5 year regulatory period to end by 2004 and supplied information reflecting that. But by the ACCC draft decision being issued in May 2001, NT Gas had revised its information to allow the regulatory period to end in 2006. The ACCC final decision was issued in December 2001 and this included more information from NT Gas which provided sufficient details to enable the ACCC to determine an access arrangement out to 2011.

NT Gas advises that it S&M usage in the base year was atypical. This is not really the case as the following figure shows.



Source: NT Gas applic, ACCC FD

For most the current period, S&M expenditure shows that the base year S&M is indeed typical and can therefore be rightly used as a benchmark for the next period forecast.

Additionally, as NT Gas has advised that the bulk of its capacity has been contracted for a considerable period, and that it expects that only small amounts of gas will be contracted to users other than PWC, it seems inappropriate that NT Gas should be seeking to increase its marketing efforts when it is a monopoly provider of the gas transmission services in the Territory.

3.3 Benchmarking

In its submission, NT Gas points out that on a comparative basis its opex is reasonable, considering its length and the country side it traverses. It also observes that it is difficult to “normalise” between comparator pipelines due to the differences.

The NTMEU concurs with this, but considers that best comparator for any monopoly service, is actual performance costs when there is a strong incentive to reduce costs. In the case of AGP, NT Gas has had a decade of regulatory oversight of its performance and was aware that it would be able to retain any under-run on opex. This means that self benchmarking (ie actual performance) provides the most appropriate benchmark for assessing the reasonableness of future costs. The NTMEU has used this approach consistently throughout this submission.

NT Gas does provide two benchmarks for its opex performance - $ opex/length and $ opex/diameter*length. NT Gas then demonstrates that the 2009/10 opex as recorded is demonstrably efficient when compared to other pipelines. The NTMEU concurs with this assessment.

The NTMEU notes that the 2009/10 actual opex provides a reasonable starting point for further development, but as noted above, the NTMEU does not agree with NT Gas about the step change adjustments NT Gas has made to the 2009/10 actual opex.

The fact that the 2009/10 actual opex is seen as being efficient does not mean that the forecast opex for the next period is also efficient.

3.4 Summary of opex

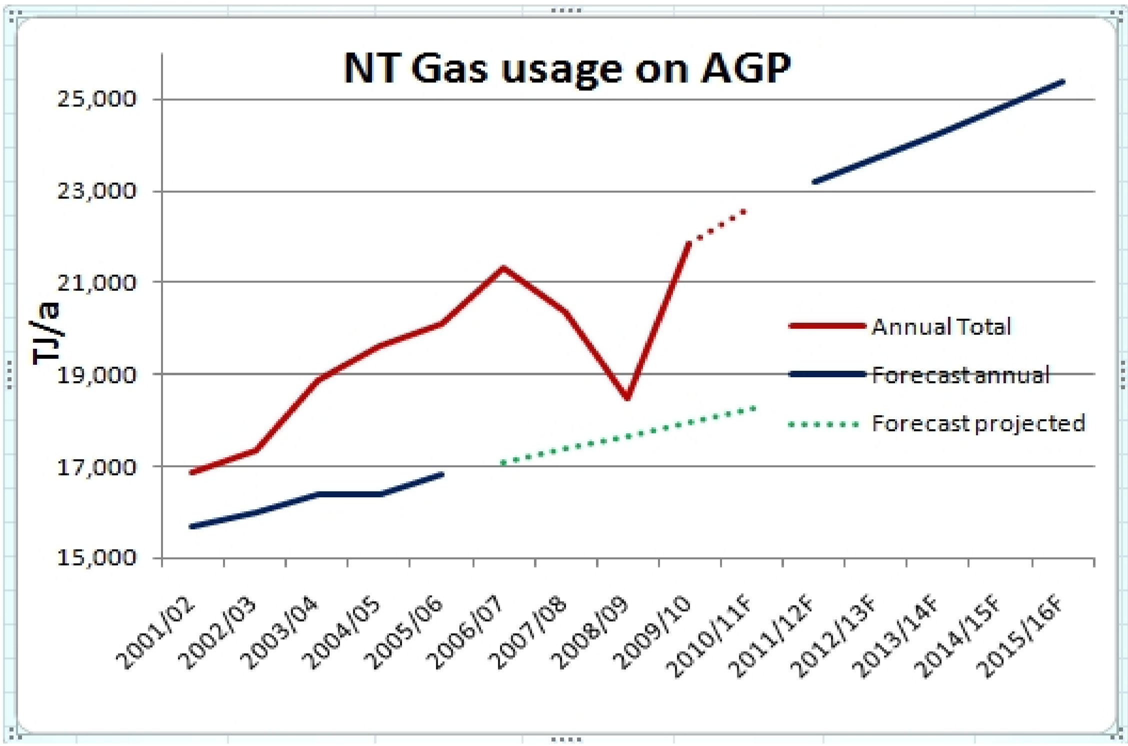
Based on trends, it would be expected that future opex would be some $9m in 2011/12 rising to $10m by the end of the period. This increase would allow for any escalation of future costs as well. There appears to be little reason for the opex to increase by 40% to an average of $14.2m pa as there is virtually no expansion of the pipeline to justify any scale growth.

In 2001 the ACCC assessed the opex claimed by NT Gas and based on some benchmarking and other assessments, determined the opex sought by NT Gas was reasonable. Throughout the current period, NT Gas consistently under-run both the ACCC allowance and NT Gas' own opex forecasts. This provides clear evidence that the opex needs have been self benchmarked by NT Gas and the current opex is indeed a reasonable allowance for the AGP.

Overall, NT Gas has made claims for massive increases in opex that will provide little benefit to users. Further, NT Gas has provided little justification as to why such large cost increases are needed or are even reasonable.

4. Forecast gas demand

Over the past decade, gas transportation on the AGP has increased at the rate of 3.5% annually although the bulk of this has been contracted to PWC. The historical forecasts, actual usage and forecasts for the next period are shown on the following figure. This shows the actual usage and the forecasts provided by NT Gas for the current period and the next period. As NT Gas did not provide forecasts for the latter half of the current period, NTMEU has projected the forecasts based on constant growth.

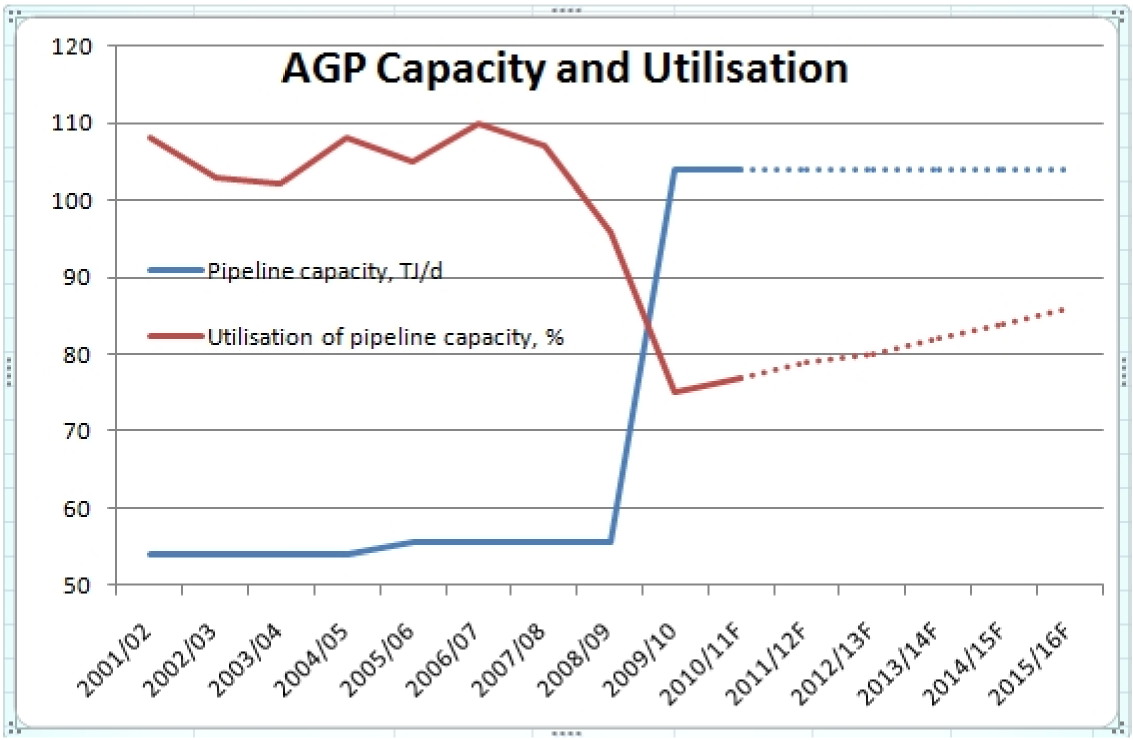


Source: NT Gas applic, ACCC FD, NTMEU calculations

The figure shows that NT Gas has not only increased capacity of the AGP through its connection with Bonaparte Gas pipeline (BNP)[5], but sees that there will be an increasing usage of gas because of this.

[5] BNP is an unregulated pipeline wholly owned by NT Gas

The following figure demonstrates this and why there is an expected surplus in capacity available in the next period.



Source: NT Gas applications, NTMEU calculations

Pipeline capacity is usually measured in the maximum daily quantity (MDQ) that can be transported. As the figure shows, NT Gas has been able to utilise a greater capacity than what the pipeline was rated at, indicating that in the past NT Gas probably under-rated the pipeline capacity. Since the connection of AGP with BNP, the capacity of AGP has been increased, providing a significant amount of spare capacity for use by users other than PWC.

From the NT Gas statements, it appears that the total capacity of AGP (and of BNP) has been contracted to PWC. Thus in practice, there is considerable interruptible capacity available for use by others with little chance that there will be interruptions for many years. Particularly there will be capacity for southward flows from Ban Ban Springs as the demand of PWC for gas to power stations south of Ban Ban Springs (eg Katherine and even Alice Springs) will not use the available capacity for such flows.

The forecast of gas demand growth based on the underlying growth trends exhibited in the current period appear to be consistent, but may in fact understate the real growth now that this is spare capacity in the transmission system. The AER should assess whether the forecast usage is likely to be higher than forecast due to there being more capacity available.

However the current actual usage is well in excess of the forecast usage by an average of ~15% each year, and over the nine years of recorded performance NT Gas has transported an average of nearly 2800 TJ of gas more than it forecast it would.

The implication of this over-run in transportation is significant. The tariffs were set on the basis of the forecast was correct and therefore the unit rates ($/GJ) were set higher than they should have been. Although NT Gas had most of its revenue achieved from the foundation contract with PWC, if this had not been the case, NT Gas would have received much more revenue than the ACCC considered was appropriate. In fact, NT Gas would have received some $60m more in revenue over the first nine years of the current period than the ACCC expected would be the case. To put this into perspective, NT Gas would have received the benefit of an additional 20 month of revenue (based on the base year revenue) for no additional cost to it.

As the bulk of the gas is used for power generation (and NTMEU members are all electricity users) the NTMEU is concerned that the renegotiated contract between PWC and NT Gas does not allow such massive over-runs to be passed into the price for gas delivered to PWC generation sites.

The AER needs to be cognisant of the potential for NT Gas to over-recover its allowed revenue by under-allowing the amount of gas that might be transported, particularly as there is now significant spare capacity available that is likely to be used now that there is an awareness of this fact.

5. Cost of capital and revenue

5.1 Cost of capital

NT Gas commences its claim for the weighted average cost of capital (WACC) to be used with a statement of what Gas Rule 87 requires, which is:

> **"87 Rate of return**
>
> (1) The rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.
> (2) In determining a rate of return on capital:
> (a) it will be assumed that the service provider:
> (i) meets benchmark levels of efficiency; and
> (ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice; and
> (b) a well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be used; and a well accepted financial model, such as the Capital Asset Pricing Model, is to be used."

It is also pertinent to quote from the second reading speech[6] made by the Minister (Mr P Conlon) when the new National Gas Law was introduced in 2008. The Minister explained that the national Gas Objective has an over-arching influence on the gas market and that the most important aspect is that these monopoly services be provided in the "long term interests of consumers". He noted

> "The long term interest of consumers of gas requires the economic welfare of consumers, over the long term, to be maximised. If gas markets and access to pipeline services are efficient in an economic sense, the long term economic interests of consumers in respect of price, quality, reliability, safety and security of natural gas services will be maximised. By the promotion of an economic

[6] SA House of Assembly - Wednesday, 9 April 2008, Page 2884 onwards

> efficiency objective in access to pipeline services, competition will be promoted in upstream and downstream markets."

Amongst other things the Minister also noted that the Rules are to be developed based on six principles, the first of which he explained as follows:

> "The first of these principles requires that a regulated service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing services, complying with a regulatory obligation or requirement or making a regulatory payment. At least efficient cost recovery is vital if service providers are to maintain their gas networks in order to meet community expectations of the service levels they receive, and to undertake further investment to serve Australia's growing population."

Effectively, combining these two elements the Minister states that the service provider should receive, as a minimum, the efficient cost for providing the service, but no more than what is efficient over the long term.

In developing the WACC therefore great care has to be taken to ensure that the outcome represents efficiency, or in other words, reflects an outcome that reflects the needs of the business rather than the wants of the business. NT Gas has provided a development of the WACC based on its "wants" rather than its needs.

Some two years ago the AER devoted considerable time to developing a series of WACC parameters that reflected the market needs. Since then it has been encouraged by regulated businesses to significantly change these WACC parameters, always in a direction that favoured the regulated businesses. Where the regulated businesses considered the AER decision was favourable they have declined to seek a change.

In following this practice, regulated entities have failed to recognise that the WACC parameters comprise an inter-related set where changing one has an impact on another. The regulated businesses have attempted to "cherry pick" those they like and change those they don't. The AER must remain alert to this practice.

In this submission NT Gas has sought increases to the debt margin, equity beta and gamma whilst continuing with the AER settings of market risk premium and gearing. The NTMEU considers that the AER WACC settings should be remain as determined in May 2009.

5.1.1 Debt margin

NT Gas seeks a debt margin of 5.46%. This is significantly higher than the debt margins the AER has agreed to in recent decisions. More to the point the AER has been awarding lower debt margins with each recent decision indicating that debt margins, which were higher as a result of the global financial crisis, are now returning to more historical levels. NT gas seems to ignore this obvious trend and sees that it should have a debt premium higher than any the AER considered appropriate in the immediate post crisis period.

NT Gas comments that the loss of the CBA Spectrum data should not of itself vary the approach the AER has previously taken where the CBA and Bloomberg data were averaged. NT Gas goes on to oppose the use of the real debt raising made by APT (NT Gas major shareholder) as it sates (page 108):

> "NT Gas is therefore concerned that referencing the APT bond to estimate the debt margin that will apply to the AGP removes the benefit that would otherwise accrue to the business because it was able to implement an efficient and innovative financing structure. The APA Group is also funding an asset base of some $5 billion in total. This is likely to well exceed the size of the 'efficient benchmark firm' and is some fifty times the size of the AGP's capital base."

What NT Gas totally overlooks is that it is only entitled to efficient costs in providing the service – it is not entitled to seek a premium on efficient costs just because the external data might prove to be overstated compared to what is actually achieved in the market place. If a more efficient sourcing of funds provides a better outcome for consumers than just relying on the data provided by one research entity which has such a small population of inputs that makes the output a mix of a small number of interpolated and extrapolated data points which have marginal relationship to each other, then the more efficient actual outcome must carry more credibility.

To this end, the NTMEU has appended a report (appendix A) provided by its affiliate (Major Energy Users) for the current review of the Envestra gas distribution pipelines in SA. This paper by MEU posits that the AER is incorrect in its current approach to setting debt risk premiums as it does not comply with the Gas Law (and its intent as outlined in the second reading speeches noting that the Electricity and Gas Laws have been harmonised) or the Gas Rules.

The Gas Rules are quite explicit - the rate of return must be efficient and use a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice. In this regard, although NT Gas purports to have benchmark gearing of 60% debt, in fact its major shareholder APA Group is geared at 74% (source CommSec and APA 2010 annual report) and was so at the time it issued the bonds. This high gearing could have added to the cost of the debt acquired

If the major shareholder and provider of capital to NT Gas has used an efficient financing structure to actually achieve a benchmark debt risk premium, this must be considered to be best practice and the actual outcome must be used. In fact as APA is more highly geared than the benchmark and despite its lower ranking (at BBB), it achieved a bond rate of 7.97%[7] which after deducting the rate for a risk free bond delivers a debt risk premium of in the range of 250-270 bp. The expectation is that as

[7] Quoted by AER in its paper: "AER draft approach for measuring the debt risk premium for the Victorian Electricity Distribution Determinations, 27 September 2010"

the benchmark for the notional AGP service provider is geared lower and has a higher credit rating, an efficient debt risk premium would be even lower.

Even at this level, debt risk premium is still twice the DRP that applied prior to the global financial crisis and twice that of the level the Queensland government advises it's T-corp charges its state owned energy network businesses[8]. As the Queensland government advises, its T-corp is to charge a debt risk premium that is the equivalent of a market based rate , even though the T-corps are to charge business their own businesses as advised by

5.1.2 Equity beta

NT Gas considers that as it is subject to stranding risk, due to the run down of the Amadeus Basin reserves, then it is entitled to a higher equity beta (to unity) to reflect this stranding risk.

This issue was addressed by the ACCC in its final decision in 2001 where it stated (pages viii and ix):

> "This *Final Decision* demonstrates the Code's flexibility to accommodate the specific characteristics of the ABDP. In its access arrangement, NT Gas sought a higher WACC as compensation for the risk that the pipeline might be stranded after 2011. The Commission maintains that the risk of stranding should be managed through accelerated depreciation rather than a premium on the return on equity. This will enable NT Gas to recover most of its capital investment by the end of 2011 and recognises the reasonable expectations of investors, lessees and users as reflected in the Gas Sale Agreement and lease arrangements. The gas transmission pipeline from the production points to the users is leased to and operated by NT Gas as trustee of the Amadeus Gas Trust."

[8] See appendix B

As noted in sections 2.1 and 2.2 above, AGP has been significantly depreciated as the ACCC considered was appropriate, and therefore the risks associated with any potential stranding have been significantly reduced.

Further, in its new submission, as well as being allowed accelerated depreciation in the current allowances, what NT Gas fails to note is that the AGP was debt financed by the banks led by ANZ. Experience with banks funding infrastructure assets is that they expect to have risks (such as stranding risks) minimised. How this would be done is that the contract from PWC (banked by the NT government) would be a sufficient duration so as to allow the banks to recover all of the capital within the contract period.

The advice of NT Gas to ACCC in the 2001 review and repeated again in the new application, confirms that the bulk of the risk of stranding was eliminated by a rapid depreciation of the assets. This is just sensible financial management practice. Because of the foundation contract, NT gas risks have been reduced below that of other regulated energy infrastructure providers who do not have a foundation contract that covers the entire capacity of the pipeline.

However, NT Gas is even more fortunate as in 2006 it secured another 25 year contract with PWC to provide the pipeline from Wadeye to Ban Ban Springs (see appendix B). The very existence of this contract means that the AGP faces no risk of stranding because if gas flows from the Amadeus basin do cease, gas will have to flow from Ban Ban Springs to Alice Springs and the AGP.

So NT Gas argument that it should have a higher equity beta than the AER determined level of 0.8, is not valid. In fact, the equity beta should be lower due to the lower risks of stranding that AGP might face compared to other pipelines.

5.1.3 Gamma

The issue of dividend imputation continues to be vexed, with the AER being challenged regularly on its assessment of gamma for the notional Australian energy network.

Dividend imputation provides a benefit for shareholders as the outcome is that shareholders are not taxed twice. The benefits of imputation are only available to Australian tax payers. NT Gas has provides an expert (Synergies Economic Consultants) to provide an argument that the benefits of tax imputation are very small (20%) but which the AER considers that the benefits are much larger (65%) although its recent decision in the Victorian EDPR considers that 50% is now appropriate.

Consistently regulated businesses are seeking to reduce the allowance the AER provides in the post tax revenue for tax imputation, as this will increase the dividends to shareholders. At every revenue reset the businesses provide an array of experts to challenge the AER considered view. NT Gas is no different.

NTMEU has no additional observations to make other than those it has already provided to the AER at recent revenue reviews, but NTMEU does consider that as the revenue approach is based purely on Australian conditions for an Australian monopoly part for the services by Australian consumers with rates of return derived from Australian parameters, then there is a prima facie assumption that the notional Australian regulated energy network provider could be owned by Australians who receive the benefits accordingly[9]. On this basis the NTMEU would expect that gamma would be 100% and therefore the AER assumption of 65% is extremely conservative.

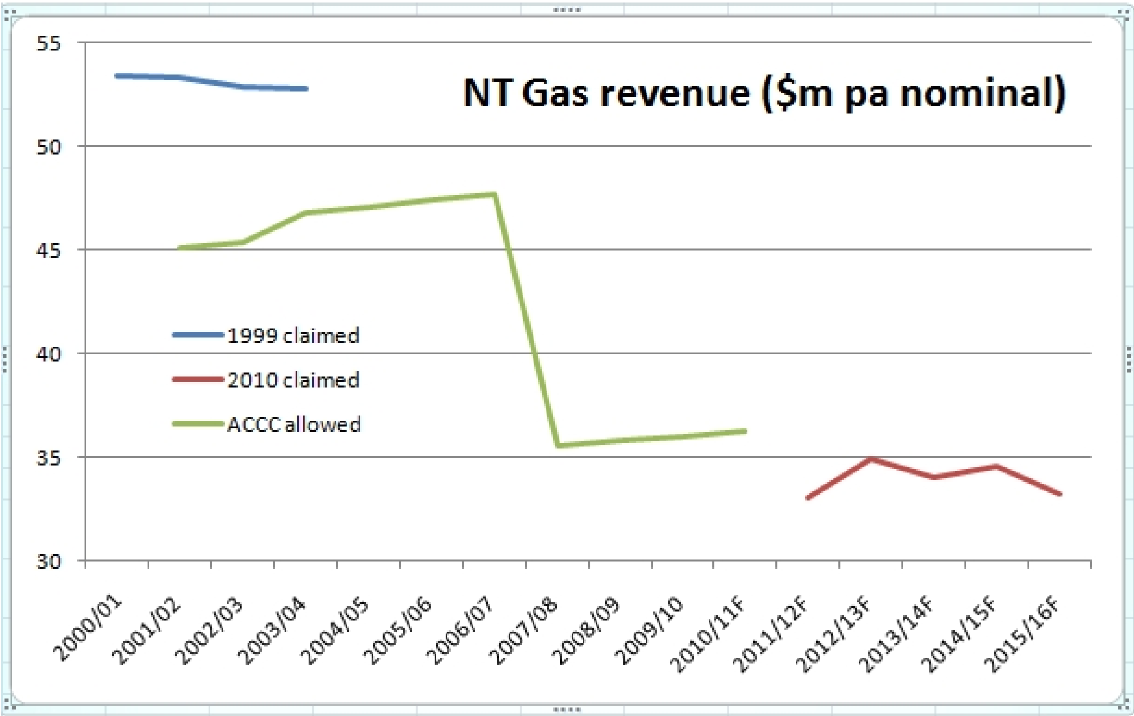
If NT Gas is correct and gamma is really 20%, this then raises the question that if such a low benefit is derived from dividend imputation, why does the Australian Government persist with providing such a complex approach for so little benefit. Because it has been

[9] The ECCSA acknowledges that such an assumption is not based on actuality as, for example, a large shareholding of APA group is held by a Malaysian company Petronas.

maintained, the NTMEU considers that gamma is significantly higher than 20% and probably much closer to the AER estimate of 65%.

5.2 Revenue

In its application NT Gas has provided a calculation which develops the targeted revenue it considers results from its assessment of the various cost inputs. The following figure shows the nominal revenue claimed by NT Gas in its 1999 application, the nominal revenue allowed by the ACCC in its final decision in 2001, as well as the new revenue sought by NT Gas for the next period. The significant fall in allowed revenue in 2007 relates to the changes in depreciation rate.



Source: NT Gas applications, ACCC FD

The new revenue schedule shows that NT Gas seeks between $33m and $35m although NT Gas has also provided a “smoothed” revenue stream as well.

NTMEU considers that the revenue stream claimed by NT Gas is considerably overstated and needs to be reduced based on the comments in earlier sections. The NTMEU assertion is supported by other observations made by NT Gas and its major shareholder, APA Group.

On page 131 of its submission, NT Gas asserts that AGP is expected to return to APA some $29m of the total $689.3m of expected APA revenue. Thus there is an expectation from APA that AGP will contribute some $5m pa less than NT Gas has claimed it should have.

This inconsistency in data provided supports the NTMEU contention that NT Gas has significantly overstated its opex and WACC needs

5.3 Comparative data

APA has reported[10] that the NT Gas transportation contract for the NT Gas owned 287km long Bonaparte gas pipeline will deliver some 30 PJ pa of gas for the next 25 years for a contract value of $400m. Separately, the pipeline has been costed at $170m[11]. Using this data, some useful information can be developed by applying the building block principles used by the AER.

It is pertinent to use the Bonaparte gas pipeline for a comparator because it has similar ownership and operates under similar conditions to the AGP, with the same operators and maintenance crews.

To provide an outcome consistent with the basics of the contract, opex has to be no more than the current rate for AGP (ie $5,000/km in submission table 9.6), be depreciated over a period between 25 to 50 years and have a real WACC of no more

[10] See report in appendix B
[11] ABC news, Dec 9, 2008

than 5% (or a nominal WACC of 7.5%), all assuming a rate of general inflation of 2.5% pa and labour inflation (as claimed by NT Gas in section 9.3.2) at 1.5% real.

The notional pre tax tariff for the 30 PJ/a transported, would range between $0.45/GJ to$0.58/GJ depending on the depreciation assumptions.

This comparative analysis provides useful support for the NTMEU views that NT Gas has considerably overstated the opex and WACC it needs for AGP.

6. Reference Tariffs

NT Gas advises there is no firm haulage capacity available on the pipeline as this is currently all contracted under pre-existing agreements. These pre-existing agreements are for haulage from Amadeus Basin to Darwin or from Ban Ban Springs to Darwin. Services that are likely to be sought[12] are:

- Firm backhaul from Ban Ban Springs or Wickham Point southwards
- Interruptible supply from Amadeus Basin northwards to Darwin
- Interruptible supply from Amadeus Basin, Ban Ban Spings and Wickham Point to take-offs south of Darwin.

The variability and/or combination of the potential flows (other than the firm northwards contract by PWC for supplies to its power stations) means that, depending on the form of the firm contract for northward flows to PWC, NT Gas has the ability to seek higher revenues from the pipeline than are implied by regulation of a monopoly asset.

The fact that the pipeline has been subject to accelerated depreciation under the current access arrangement and the much greater flexibility of gas flows now possible, there is potential for the pipeline owner to now over-recover the revenue seen as needed for a significantly depreciated regulated monopoly asset. This means that the AER should examine the main contract NT Gas has with PWC to ensure that the pipeline owner does not use the increased flexibility to earn more than is appropriate for this monopoly asset.

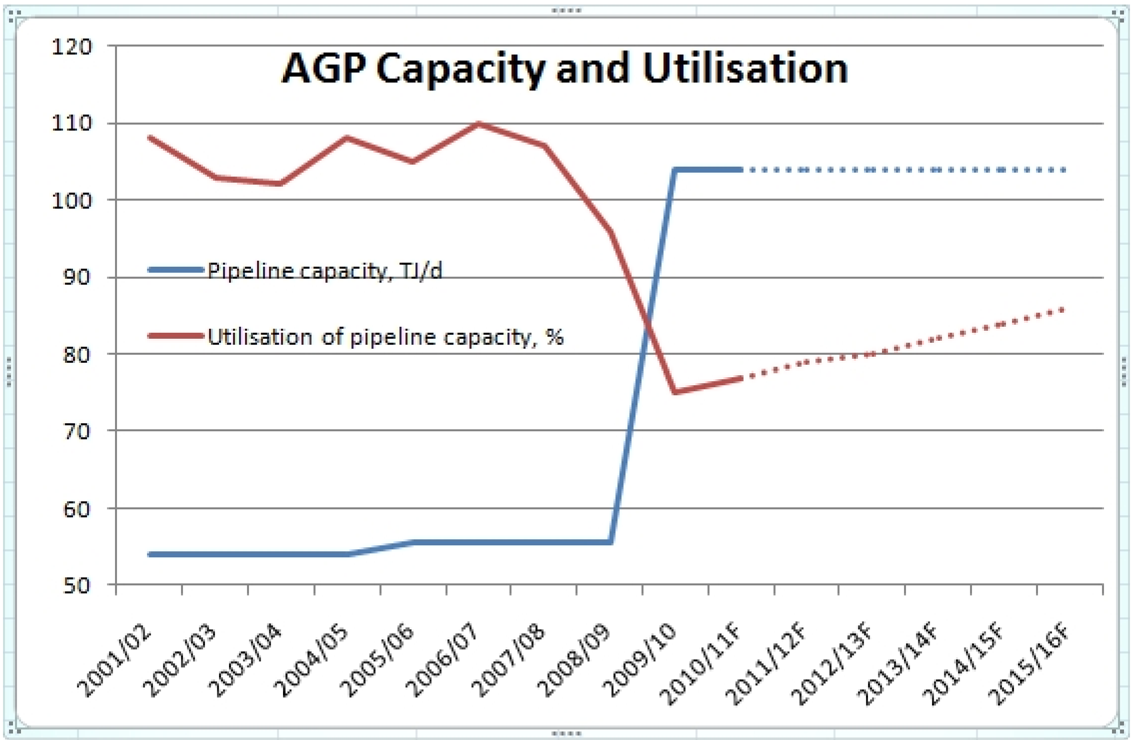
[12]This is because the dominant user (PWC) is sourcing significant amounts of gas from the Wadeye LNG plant which connects to the AGP at Ban Ban Springs

NT Gas comments in its submission that as the likely services to be used will be small in quantity (because the main capacity is contracted), that contracting the remaining likely capacity is minor and therefore setting a reference service is not warranted, other than for a firm service which is implied to be for northward flows for delivery south of Ban Ban Springs.

The NTMEU considers this approach is insufficient as there is likely to be a requirement for southward flows from Wickham Point and from Ban Ban Springs which NT Gas could offer as a firm service. Further, NT Gas advises that there is likely to be some firm northward capacity for delivery south of Ban Ban Springs and potentially some capacity from Ban Ban Springs northwards due to increases in pipeline capacity.

The AER should set reference services for these uncontracted capacities (particularly the backhaul services) as these are likely to be is needed by existing and prospective users as the basis on which to "negotiate" for their specific needs with the monopoly provider NT Gas, even though in total, the amount of gas is likely to be small in comparison to the amount of gas hauled for PWC.

That there will be significant spare capacity for interruptible usage is also apparent from the data provided by NT Gas. The following chart shows the rated capacity and the utilization of capacity both actual and forecast. This combined with the forecast that growth in demand will increase by only 2.2% pa, indicates that there is ample capacity in AGP for the next decade. As there is relatively "firm" interruptible capacity available for the next 5 years and probably longer, then a reference interruptible tariff could well be established.



Source: NT Gas submission

The NTMEU notes that NT Gas has decided that it will unilaterally decide (page 14) whether or not expansions will be included in the access arrangement, but if it does seek inclusion, then it will seek AER agreement. The NTMEU considers that if capex included in the access arrangement is used for expansion of the pipeline capacity, then this expansion must be automatically integrated into access arrangement.

Further, if the capacity increases as a result of the new arrangements (ie higher pressure and shorter distance for the flow) then this increase in capacity should be incorporated into the access arrangement.

Appendix A

Australian Energy Regulator

Discussion Paper

on

Measuring the Debt Risk Premium

A Response
by
The Major Energy Users Inc
December 2010

Assistance in preparing this submission by the Major Energy Users Inc (MEU) was provided by Headberry Partners P/L and Bob Lim & Co P/L
The content and conclusions reached in this submission are entirely the work of MEU and its consultants

Addendum

Issue 1 – Evidence of actual interest rates and DRP

Since writing and submitting this analysis an MEU affiliate was provided with advice from the MCE SCO regarding the cost of debt provided by the Queensland Treasury Corporation to the Queensland government owned electricity distribution and transmission businesses Powerlink, Energex and Ergon.

This advice is as follows:

> "... with regard to financing arrangements for the Queensland distribution GOCs, it is true that they source all debt from Queensland Treasury Corporation other than non-recourse funding.
>
> However, the *GOC Act 1993* provides that the State does not guarantee any obligation incurred by a GOC, unless the liability is expressly undertaken on behalf of the State. Under this arrangement QTC operates the same as any other financial institution providing debt facilities to a client. It is essentially an intermediary financial organisation will enters the domestic and international markets to source the required funds.
>
> In accordance with the National Competition Policy principles, GOCs are expected to operate on the basis that they do not gain advantages or disadvantages by virtue of their Government ownership. One of the most significant advantages GOCs could enjoy is the ability to borrow funds at a lower rate than private sector competitors, on the basis of the State Government's credit strength. That is, the interest rate at which GOCs could borrow funds might reflect the creditworthiness of the State of Queensland rather than the stand-alone credit of the individual GOC. To the extent this resulted in a lower cost of capital, GOCs would derive a competitive advantage over private sector competitors.
>
> In order to prevent any such advantage, the Competition Principles Agreement requires a notional charge to be applied to the cost of debt for all GOCs. As a party to the Agreement, the Queensland Government has previously notified its GOCs of the application of a Competitive Neutrality Fee (CNF) to all borrowings and financial arrangements in the nature of debt obligations. The CNF is individually determined for each GOC in accordance with its stand alone credit rating and the market cost of debt, to ensure that the cost of funds paid by a GOC is equivalent to a similarly rated private sector entity."

This response supports the MEU contention that government owned electricity businesses pay an interest rate on the debt provided by the related treasury corporation at a rate considerably below the corporate bond rates used by AER in setting the WACCs.

There are five electricity entities that are “pure” network providers owned by governments – Powerlink, Energex and Ergon[13] in Queensland, Transgrid in NSW and Transend in Tasmania.

Of the remaining government owned electricity network businesses, EnergyAustralia, Integral Energy and Country Energy have significant retail functions and therefore analysis of debt premia for these entities would have to reflect that this retail function was a large part of their activities and would therefore distort the outcomes of any analysis.

The advice MEU received from MCE SCO was that the treasury corporations add a margin to the base cost they incur for funds (the Competitive Neutrality Fee) to reflect the debt risk premia that would be available to their fully related entities if they were required to access debt from the open market.

Reviewing the annual reports for these five businesses shows that each receives its debt funding from its related treasury corporation. Based on 2009/2010 financial year data from annual reports (ie after the global financial crisis) the actual financing cost and average debt for each (ie the arithmetic average of the debt levels at the start of the year and at the end) was used to calculate notional rate for debt. From this was deducted the average 10 Commonwealth bond yield (which averaged 5.50% for the financial year). The following table summarises the analysis.

Entity	Interest paid in 2009/10 $m	Average debt used in 2009/10 year $m	Effective interest rate %	Average 10 year bond yield % 2009/10	Notional DRP bp	AER DRP bp	Date of AER decision
Powerlink	196	3189	6.1	5.5	60	114	2007
Energex	225	3968	5.7	5.5	20	333	2010
Ergon	243	3826	6.4	5.5	90	333	2010
TransGrid	106	1501	7.1	5.5	160	349	2009
Transend	33	503	6.6	5.5	110	349	2009

[13] Ergon does carry out some retailing functions but the bulk of its activities are network provision

Consistently the treasury corporations have charged the government owned businesses notional DRP levels below 160 bp which reflects the DRP used historically in regulatory decisions. Equally the AER has calculated a DRP above 300 bp in recent years, although the DRP calculated in 2007 by the AER was consistent with the levels previously used by the ACCC and jurisdictional regulators, and still currently used by T-corps.

It is accepted that the financial values used in deriving the notional DRP might have some bias in them and therefore might not be fully comparable, but the magnitude of the difference between the actual interest charges and the AER calculated interest charges is so great as to clearly demonstrate there is a very large problem with the AER approach.

The analysis raises two basic questions:

1. Why T-corps have calculated lower DRPs than has AER even since the global financial crisis, bearing in mind that the T-corps are required under the Competition Principles Agreement, interest rates that reflect the open market cost of debt.
2. Why the AER has provided the entities with a DRP far in excess of the debt costs that the entities are actually incurring, accepting that the AER is required to allocate debt costs that an efficient entity would incur.

In its draft decision on the Victorian EDPR (page 505), the AER advised that it sought to provide a debt rate that "equate[d] to a commercial cost of debt". This is what the T-corps are required to do under the National Competition Policy.

The AER has advised that it has used the approach implied in the Rules and its own Statement of Regulatory Intent and this has resulted in the higher values for DRP than used historically. The T-corps have calculated market based interest rates, at values that are higher than the average 10 Commonwealth bond yield.

There is a basic difference between the market based cost calculated by three different T-corps and the way the AER has calculated the market based cost.

There is no doubt that the AER approach has resulted in a massive increase in unnecessary revenue (and hence increased profit) for the regulated entities from its approach in awarding such a large debt risk premium compared to what entities are actually incurring.

The AER has advised that its approach (using corporate bond rates) is the only method they have of independently assessing realistic debt costs. The same can be said of the T-corps who have set actual interest rates considerably lower than the AER.

Issue 2 – Requirements of the National Electricity Law

The National Electricity Law requires in section 7A(5) that a revenue and pricing principle is:

> "A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates."

During the second reading speech (2007 when the Law was being debated, the Minister (Pat Conlon) stated in relation to this principle:

> "[This] principle ensures [that risks are appropriately compensated for when determining efficient revenues and prices] by requiring that prices and charges for the provision of regulated network services, allow for a return commensurate with the regulatory and commercial risks involved in providing the service to which that price or charge relates."

The various T-corps also have this obligation in that the funds they lend to the regulated entities, is lent at a rate reflecting the risks involved. The T-corps responsibilities go further in that under the Competition Principles Agreement they must lend at a market rate to their entities.

The T-corps must provide debt to the related regulated entities at market rates. It is therefore an obligation of the AER to recognise that the entities have been provided with debt which is provided at a rate which recognises the regulatory and commercial risks involved. In disregarding the rates at which the regulated entities have actually acquired their debt, the AER has totally ignored this relevant principle in the Law.

Issue 3 – The Market Objective

The Market Objective requires the promotion

> "...of efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to

> price, quality, reliability and security of supply of electricity, and the reliability, safety and security of the national electricity system".

The second reading speech for the National Electricity Law (2005)[14] makes it clear that investment and use of electricity services will be efficient when services are supplied in the long run at least cost.

To provide a debt risk premium to a regulated entity at a level higher than the price at which a lender will lend to the entity in order to provide those services is not efficient in the terms that the Minister clarifies in his second reading speech.

For the AER to include for a higher cost of debt than an entity can actually source the debt in the open market is not efficient.

Conclusions from this additional analysis

1. There is a basic difference between what the AER considers is a market based DRP and what three different government treasury corporations consider is an appropriate debt premium to allow for their obligations to meet the requirements of the Competition Principles Agreement. The weight of evidence does not support the AER outcomes.
2. The AER is required by the National Electricity Law to ensure that the rate of return reflects the regulatory and commercial risks faced by the entity. This means that if lender is prepared to provide funds at a rate less than the AER might consider to be appropriate, then the AER must not provide a rate of return that is based on what the market considers to be efficient.
3. The Market Objective requires the AER to allow only efficient costs to provide the service as efficiency will deliver the least cost to consumers. If an entity can secure debt at a lower cost than that assessed by the AER, then to meet the Objective, the AER must use the actual costs, and not a higher cost.

[14] See appendix 1.2

1. Preamble

In its Consultation Paper on Measuring the Debt Risk Premium (DRP) in relation to the Victorian Electricity Distribution Price Review (EDPR), the AER is attempting to establish a better mechanism to calculate an appropriate return on the debt portion of the weighted average cost of capital (WACC), as the current approach is quite flawed due to the absence of supportive data.

Under the building block approach to setting regulatory revenues, the revenue includes an amount derived from the amount of capital provided (the Regulatory Asset Base) multiplied by the weighted average cost of capital (WACC). Previously the AER had relied on estimates from data service providers such as Bloomberg and CBA Spectrum to develop the DRP to be used in the weighted average cost of capital formula which was then applied to capital provided by the regulated network service providers.

In its draft decision for the Victorian EDPR the AER observed (page 505):

> "The DRP (or debt margin) is added to the nominal risk-free rate to calculate the return on debt, which is an input for calculating the WACC. The DRP is the margin above the nominal risk-free rate that a debt holder in a benchmark efficient DNSP is likely to demand as a result of issuing debt to fund the business operations. **It is intended to equate to a commercial cost of debt**. (Emphasis added)
>
> The underlying criteria used by the AER in its SORI[15] in relation to the credit rating level were:
>
> - the need for the rate of return to be forward looking that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
> - the need for the return on debt to reflect the current cost of borrowings for comparable debt
> - the need for the credit rating level to be based on an efficient DNSP
> - the need to achieve an outcome that is consistent with the NEO
> - the need for persuasive evidence before adopting a credit rating level that differs from the level that has previously been adopted for it"

[15] Statement of Regulatory Intent

The MEU agrees with the AER that in setting the debt risk premium (DRP), the outcome should "equate to a commercial cost of debt" reflecting the costs an efficient electricity network provider would incur.

It must be remembered that under the building block approach, the provision of debt is intended to be a "cost recovery element" (similar to opex) and not a source of profit – profit for the entity is recovered in the equity risk premium.

The allowance the AER should therefore include for DRP should reflect the actual costs an efficient provider would incur. This means that the AER should develop a methodology to reflect this need, ie the DRP should be that which an efficient benchmark provider would incur **in an efficient debt structure**.

2. Debt risk premium (DRP)

The debt risk premium is defined in the National Electricity Rules[16] (NER) as the premium required over the risk free rate (set as Commonwealth 10 year treasury bonds) to acquire debt and the AER, in its WACC decision in May 2009, determined that the debt benchmark would reflect a BBB+ credit rating.

The definition of DRP in the Rules is somewhat circular. The Rules define the risk free rate, and then define the DRP as the difference between the risk free rate and the:

> "...the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate."

Effectively the NER considers the return on debt (k_d) is to be the:

> "...the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to [10 year Commonwealth Bonds]."

2.1 DRP and the NEO

The National Electricity Objective requires the "efficient investment and efficient operation of" network services as these will provide, in the long term, the "least cost" to consumers[17]. It is not efficient to pay a regulated entity a higher return than is needed.

[16] See appendix 1.1 which includes the relevant excerpts from the NER
[17] See appendix 1.2 – second reading speech for NEL

Efficiency implies, in relation to the DRP, that the AER must determine a mix of debt (a debt structure) that is efficient, and not be hidebound to assessing DRP based on using just one type of debt structure. As the NER does not define what corporate bonds are to be, then the AER must assess what the DRP should be in terms of the efficient mix of debt so that its measure of DRP is based on an efficient debt structure.

2.2 Efficient debt

The MEU considers that an efficient debt structure is a mix of bank borrowings and debt provided by the open market. However in May 2010, in its final decision on ETSA, the AER stated (clause 11.4.3.4) that

> "The AER notes that the DRP is set with regard to the Australian benchmark BBB+ corporate bond rate. The experience of two particular businesses' (SP AusNet and ETSA Utilities) recent capital raisings in isolation are not directly relevant but experience of individual businesses will be reflected in the fair value curve that is used to establish the benchmark DRP.
>
> The AER determines the benchmark DRP by averaging the yield on a 10–year BBB+ corporate bond over the averaging period of 18 business days between 29 March and 23 April 2010 (to match the period used for estimating the risk–free rate)."

What the AER is effectively stating is that actual observations of debt raised and debt structures used by exactly equivalent entities are not relevant, but might impact on the "fair value curve" used to calculate the DRP based on a range of other non-related entities seeking debt from the open market. Further the AER will only consider that debt acquired in the open market is applicable to setting DRP.

2.3 Debt is not just "bonds"

The NEO requires the development of the weighted average cost of capital (WACC) along with many other elements, to reflect an efficient rate of return. To achieve this, the NER Clause 6.5.2(b) considers that debt structure must equate that used by:

> "... investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the *distribution* business of the provider"

Clause 6.5.4 (e)(2) goes even further in requiring the AER to set the return on debt (that is the risk free rate plus the DRP) which:

> "…. reflect[s] the current cost of borrowings for comparable debt"

This clearly requires the AER to not only just consider the way the open market might price debt but to include other forms of debt an efficient provider would use in addition to debt sourced from the open market.

An efficient provider would acquire its debt on a portfolio basis. A portfolio would include debt from a mix of sources – from a number of banks, from the open market (often referred to as bonds), and internal sources (such as funds held against future liabilities including employee provisions, trade creditors, etc) – each type being addressed with a variety of term lengths and maturity dates. It would be inefficient (and unwise) for a business to have all debt maturing at the same time.

The AER approach of assuming that all debt will have a cost the same as that obtainable from the open market does not reflect efficient debt provision. From the observations of Credit Suisse noted in section 4 below, it would appear that the AER approach of basing the DRP on just the open market for debt, does not deliver the least cost to consumers, as would be expected from an efficient provider.

The ACCC in its final decision on ElectraNet revenue reset in 2003 confirms this view (page 25) when it stated:

> "The Commission understands that the interest margin associated with bank issued debt is generally lower than capital market interest margins. However, information on the debt margin associated with bank issued debt is generally not widely available. The Commission therefore considers that it is reasonable to use capital market data as the benchmark, which is biased in favour of the TNSP."

Under the National Electricity Code, the ACCC was permitted to include such explicit conservatism, but under the NER, the AER is required to apply a level for the WACC that is "economically efficient" and delivers "least cost" over the long term to consumers. This means that such explicit conservatism is not permitted.

3. Corporate bond rate

The NER does not define what corporate bonds are, but the AER has assumed that these are formal debt raisings issued on the open market by corporate entities, which are often issued under the title of "bonds".

A review of the definitions of "corporate" and "bonds" reveals that (Encarta dictionary[18]):

> "A Bond [finance] is a certificate issued by a government or company promising to pay back borrowed money at a fixed rate of interest on a specified date"

and

> "A Corporate Bond is a bond issued by a company rather than by a national or local government"

This definition of a corporate bond would reflect that any debt raised by a corporate entity if it entailed an agreement to pay back the borrowed money at a fixed rate of interest at a specified time would be a bond. It does not require these bonds to be tradeable, although the AER seems to have restricted itself to assessing the DRP based only on tradeable corporate bonds existing on the open market.

The NER does define that only Australian corporate bonds may be used in developing the DRP. This restricts the AER from following what is good debt practice – that an entity would have a portfolio of debt instruments, including debt provided by overseas entities. This restraint results in the AER having a much reduced or "thinner" market from which to develop its benchmark DRP. However such restraint does not prevent the AER from assessing DRP based on other debt instruments, providing that they are from an Australian source.

4. Previous AER and state regulatory determinations

In its submission to the AER in relation to the recent ETSA Utilities regulatory review, the MEU affiliate ECCSA observed that the DRP allowed by the AER in relation to its draft decision was excessive in light of the actual cost of debt ETSA was incurring. The ECCSA provided evidence of a Credit Suisse report[19] where CS observed, based on the AER assessment of DRP of [sic] 427 bp[20]:

[18] Similar definitions are in Collins English Dictionary and Oxford Concise Dictionary
[19] Credit Suisse, Company Update1 December 2009, "Draft ETSA decision positive for SKI", Page 3. SKI is the ASX code for Spark Infrastructure, part owner with CKI of ETSA, Powercor and Citipower
[20] In fact the CS report is in error as the AER had set a value of 429 bp

> "ETSA locked in 5, 7 and 10 year debt at an average margin of ~295bps in July - 09. On that basis ETSA will be making a ~130bps benefit than the regulated allowance reflecting its higher credit rating (A-) ... against the regulated allowance (BBB+, 10year)."

This observation provides commentary on a number of salient issues, viz

1. The AER calculation would have provided ETSA with an unearned benefit of 130 bp on the debt portion of the rate of return allowed. To put this into context, the AER would have allowed a WACC of nearly 80 bp higher than ETSA was incurring for its WACC, or nearly an additional $136m more in revenue over the 5 year regulatory period than ETSA would have actually incurred. Such a payment would not be efficient as it would not impact on the long term benefits to consumers.
2. The observation supported the ECCSA contention that an efficient provider would have a portfolio of debt instruments of varying durations
3. That a privately owned electricity network provider (as distinct from the government owned electricity network providers[21]) have a higher credit rating than BBB+ assumed by the AER in its WACC review.

4.1 Historical allowances for DRP

Prior to 2008, regulatory decisions by the national and state regulators had set a DRP in the range 90 to 150 basis points, with a median between 120-130 bp with a lowest value of 90 bp used in the TG final decision in 2005[22]. Since the beginning of 2008, DRPs have been calculated by the AER to be as high as 429 bp (ETSA DD 2010) and yet as recently as in the AER Final Decision on the WACC review in May 2009, the implied DRP is 160-180 bp.

Whilst the ACCC and state regulators also used CBASpectrum and Bloomberg data to develop the DRP, at that time the Australian bond market was more liquid and development of a DRP was more straight forward, although regulators did note that they had to manipulate the data in order to generate 10 year BBB+ bond data. However there has been significant consistency in the generated values for the DRP over the decade from the first setting of DRP (at the "Great WACC Debate of '98" conducted by the ACCC and Victorian ORG) until 2008.

[21] As the MEU pointed out to the AER it is response to the Issues Paper to the WACC review in 2008, the government owned electricity network providers have credit ratings of AA and AA+

[22] When it was the regulator, the ACCC used to assess financial indicators to identify if the WACC (amongst other elements) was set at an appropriate level

While it is accepted that the global financial crisis did have the impact of increasing the cost of debt, it must also be accepted that this impact will be relatively short lived, before the market reverts to more historical trends. To set the DRP for a 5 year period (or longer) based on effectively single point data[23], obviates the reality that over the period of the five year reset, the DRP will trend to its longer term values – this trend is already being seen in the falling values of DRP calculated by the AER.

Yet despite the observed downward trend, in the ETSA Utilities Final Decision in May 2010, the AER determined a DRP of 298bp yet one month later, in its draft decision for the Victorian EDPR, the AER set the DRP at 325 bp. This highlights that the data used by the AER is demonstrating extreme volatility and this can be attributable to the AER decision to use effectively single point data market to generate a DRP for the next five years.

That such a variation could occur in just on a month for the DPR to apply for the following 5 years is absurd and shows that the methodology is quite flawed. A well designed approach would demonstrate greater consistency in its outcomes.

5. Inaccuracies introduced by the AER approach

In addition to the fact that efficient acquisition of debt comes from a portfolio approach (types of debt, and varying maturities and durations), the AER approach fails in two other aspects

5.1 Scope of debt instruments

The single major cause of the inaccuracy of calculating the DRP is that the bulk of debt used in Australia by electricity network providers (and indeed most other businesses) is bank debt and not debt issued on the open market.

A review of the debt structure of the private electricity network businesses shows that bank debt is the major source of debt, with overseas bonds adding to it. The government owned electricity network businesses use bank debt and government bonds sourced from government owned investment vehicles such as Queensland Treasury

[23] The AER advised that for the ETSA Final Decision, it had used an averaging period of just 18 days, which in terms of the 5 year period the reset is to apply is just 1% of the time – effectively single point data

Corporation. Few, if any, electricity network businesses have sourced any of their debt from the open market. This clearly implies that an efficient electricity network provider uses other sources of debt.

For the AER to set the DRP purely on the assumption that all debt will be sourced from bonds issued on the open market does not reflect what an efficient network provider would do, and introduces significant but unnecessary inaccuracies and conservatism.

5.2 Assessing the "corporate bond" market

Clause 6.5.2(e) requires the AER to use:

> "...observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency."

The AER has admitted that it cannot comply with this clause as there is no "observed" bonds that meet these criteria either in relation to quantity, duration or rating. To achieve the outcome the AER has to **calculate** a bond yield (as distinct from observing a number of appropriate bonds) which complies with the requirement. This means the rule is unworkable and should therefore be changed.

The AER identifies in its decisions that there is a thinly traded market in Australia for debt issued on the open market. For example in its final decision on ETSA and again its draft decision on the Victorian EDPR, the AER has identified that the forecasts for BBB+ rated entities is so thin as to be non-existent, and it has to use other debt issued against other credit ratings, and then interpolate the values to reach BBB+ credit rating. Even then, the market is still thin, and the AER has used bonds raised businesses dissimilar to electricity network businesses with a different degree of non-diversifiable risk such as:

- Coles Myer (a consumer retailing business)
- Snowy Hydro (an electricity generator/retailer)
- GPT (a listed property trust)
- Wesfarmers (a coal miner, consumer products retailer)
- Santos (a gas producer)
- BBI (a diversified infrastructure owner of ports, gas transport, ship loading, etc)

Of these, none had sought bonds over more than a 6 year period.

What is salient is that no electricity network providers are listed as raising debt in this way, yet despite the NER requiring the WACC to be based on:

> "...a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the *distribution* business of the provider"

None of the entities used to provide the benchmark bond meet this very basic requirement. If there is no enterprise of a similar nature and risk to an electricity network provider, then the AER must find another approach to setting the DRP.

The trade in, and debt raisings from, corporate bonds in Australia has been greatly overshadowed by more traditional fund raisings by Australian businesses such as bank debt and equity raisings. This has caused the thin market in the "corporate bond" financial instruments.

This means that the AER has to find alternative ways of developing an efficient DRP for use in its WACC development.

5.3 Duration of the "open market" debt provision

None of the data from the open market has a debt maturity of more than 6 years (although the AER has found one – APT which issued 10 year bonds but at a different credit rating – yet the NER requires the AER to set a debt duration matching the risk free rate duration of 10 year Commonwealth bonds.

To meet this requirement the AER has extrapolated the shorter period debt to match the 10 year debt duration required. This introduces unnecessary risk.

Because of this introduced risk of extrapolation, the NER provides guidance to minimise risk where actual data is not available. For instance, when developing the risk free rate, the NER states that interpolation must be used. For example NER 6.5.2(d) requires that if there is no actual data available when setting the risk free rate:

> "...the *AER* must ... determine the nominal risk free rate for the *regulatory control period* by interpolating on a straight line basis from

> the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date."

This implies that interpolation is acceptable, but extrapolation is seen as less acceptable due to the risks implicit in its application.

5.4 Volatility of outcomes

Because of the approach used by the AER, this has resulted in a significant amount of volatility and this volatility must have a negative impact on both consumers and the network owners.

The regulatory environment should provide participants with a high level of certainty and consistency over time. If it does not, then there is a negative impact on investment, leading to greater risks for consumers. As noted in section 4.4 above, up until 2008, regulators have been setting the DRP in the range of 90 bp to 150 bp, with a median value well below 150 bp. The global financial crisis has caused the DRP to rise as lending was constrained, but in recent times, borrowing has become much easier. Equally the global financial crisis has resulted in very low (even negative) DRP values in most first world countries, as interest rates have been slashed in an endeavour to encourage investment.

Because of a very illiquid market and thin trading in Australia for bonds, the volatility of DRP calculated from tradeable corporate bonds has shown excessive volatility, especially in the wake of the global financial crisis.

The AER must develop an approach which reduces the volatility in forecasts of future movements. One of the main aspects of the AER approach is that it uses a short averaging period of time to set the forward estimates of the various variables used by it. To all intents, this means that the data is based on almost a single point in time. This introduces significant inaccuracy. For example the AER performance in forecasting the forward exchange rate has been demonstrably wrong and, with the benefit of hindsight, show gross errors were made in the forecasts[24]. Errors such as these add significantly to the risk participants have to manage.

[24] See appendix 2 exhibiting the errors in the forecasts of the $US/$A exchange rate errors used in assessing future materials costs. The purpose of this example, is not to deride the AER ability to forecast, but to highlight that in attempting to be more accurate and accommodate future changes, the outcome is exactly the opposite – that greater error is introduced by attempting to be more accurate. Because of this the MEU considers that greater certainty and consistency is achieved by using longer term averages, rather than attempting to extrapolate from observations set in a short time frame.

The AER, in attempting to be “accurate” in its forecasts, has introduced major concerns for all. The problem with using data from effectively a single point in time is that it eliminates all of the moderating effects that comes from the “smoothing” effects of time.

In developing the market risk premium (MRP) the AER has assessed MRP over the long term – many decades in fact. If the AER attempted to use a forward looking MRP based on such a short averaging duration that it is effectively a single point in time, then the MRP would swing violently from large positives to large negatives over very short periods, making a mockery of the WACC developed using these swings. The AER has recognised that investor sentiment is fickle and causes large short term movements in MRP. To overcome this variability, the AER has sensibly used time to smooth the MRP, so that the value used does not vary significantly decade on decade.

The same issues (such as investor sentiment in valuing corporate bonds) affect the DRP and cause significant short term movements such as occurred during the global financial crisis. The same logic used to smooth the MRP should apply to the setting of the DRP

6. Summary

The AER approach to setting DRP does not comply with the NER or the NEO. It does not reflect efficient DRP levels as it excludes the (lower cost) source of debt most commonly used by electricity network businesses. As the approach used by the AER is acknowledged as being conservative (and therefore a higher cost than needed) it does not deliver the least cost to consumers. Therefore the AER must develop a methodology for setting DRP which reflects the major sources of debt used by an efficient notional network provider.

In all the recent AER assessments of DRP consistency and certainty over the long term have been ignored. Regulation should lead to consistent and certain outcomes and not provide wild fluctuations in values. In this regard large fluctuations increase risk and increased risk increases costs. Implicitly, fluctuations increase costs to consumers, thereby not delivering the least cost as is expected by economic efficiency.

The risk free rate is set on a 10 year term and the DRP is intended to mirror the term of the risk free rate. However achievement of this is not possible because there is:

- No extrinsic market data that provides a clear value for DRP that can be derived from using "observable" Australian 10 year corporate bonds. This means that there is a need to extrapolate from shorter term bonds. The NER implies that where data is not explicitly provided it should only be interpolated and not extrapolated.
- Almost no market for corporate bonds for businesses of similar "...nature and degree of non-diversifiable risk ..." to electricity network businesses.
- No strong and liquid market for any corporate bonds in Australia. If there is insufficient liquidity in a market, this introduces risk and risk increases costs to consumers.

This makes the requirement in the Rules unworkable as the wording of the Rules (especially clause 6.5.4(e) as interpreted by the AER contradicts the achievement of the NEO.

7. Conclusions

The AER has up to now has based its approach to setting DRP on the assumption that the DRP is the difference between the yield of Commonwealth treasury 10 year bonds and the yield of BBB+ Australian corporate bonds of 10 year duration. To obtain the yield of corporate bonds it has used published data from CBASpectrum and Bloomberg and extrapolated the data for duration and interpolated the data to get the correct credit rating.

In fact this approach does not comply with the Objective and the Rules as it:

- Does not incorporate the DRP that applies to the bulk of the debt (bank debt) acquired by electricity network businesses
- Has only a small population of bonds to work with reducing the diversifying benefit of a large population, thereby increasing risk (and therefore cost)
- Does not comply with the requirement of comprised of businesses with similarity to electricity network businesses, because:
    - Those bonds that are listed, few reflect the similar nature and risk to electricity network businesses,
    - Those very few bonds that might be applicable are mostly not as long as 10 years causing the need to extrapolate, increasing risk

- Those even fewer bonds that might be applicable in terms of similarity and duration do not have the same credit rating as is stipulated, creating the need to interpolate from those of a different credit rating.

Despite the AER misgivings about using actual experience of the electricity network businesses, it appears to the MEU that by not doing so, the AER is not recognising the requirement of the Objective to reflect economic efficiency in setting the WACC. Economic efficiency requires that the allowance the AER is to include for DRP should reflect the actual costs an efficient provider would incur.

This means that the AER should develop a methodology to reflect this need, ie the DRP should be that which an efficient benchmark provider would incur for its debt structure and not rely data which is inappropriate, insufficient and not reflective of actuality.

To the structural difficulties identified by attempting to follow the rules, are added the fact that electricity network owners do not source the bulk of their debt from the open market, but obtain it from lower cost sources. Persisting with the current approach means that consumers will be required to pay for an inefficient and not “least cost” outcome. This is contrary to the NEO which requires efficient costs only to be charged to consumers and that the outcome should be the least cost.

Overall, the Rules are inconsistent with the NEO and, further, the AER has identified that the Rules cannot be explicitly complied with. This means that the AER should seek a rule change to make their task one which will deliver a DRP which reflects the actuality of the cost of debt as it applies to the regulated networks.

Arising from this, the MEU would recommend a number of specific aspects the AER should consider in seeking a rule change:

1. The fact that all the electricity network owners raise debt from banks and very little from public raisings in the open markets
2. The fact that some of the privately owned electricity network owners have raised debt on the overseas bond markets (and swapped this back into $A)
3. The fact that the large proportion of all electricity networks are government owned and would have a lower cost of debt than would be calculated from corporate bond markets

Whilst the AER has focused its review on the need for an outcome for the Victorian EDPR, there is the long term issue of trying to use a small and illiquid bond market to generate an accurate DRP which needs to be addressed. It is simply inadequate for the AER to try and reach a reasonable reflective and efficient DRP from the Australian tradeable corporate bond market.

8. Specific questions for stakeholders

1. Given the paucity of available data, the fact that CBASpectrum recently ceased publication of its fair yield curve, the characteristics of the recently issued APT bond and the Tribunal's recent decision on the DRP issue, the AER intends to examine the yields from the recently issued APT bond and those derived from Bloomberg in terms of their appropriateness in estimating the DRP for the Victorian DNSPs' distribution determinations. Please provide comments on the AER's intended process.

The MEU considers that the AER needs to develop a new approach to setting DRP based on what an efficient network provider would do, rather than relying on data that is inappropriate, insufficient and not reflective of what an efficient provider would do.

The MEU considers an efficient provider would source the bulk of its debt from bank loans as this is the most economically efficient approach to sourcing debt.

2. Given the uncertainty in determining whether yields from Bloomberg or from the APT bond are more appropriate in setting the DRP, the AER intends to take an average of the two. Please provide comments on the AER's intended methodology.

The MEU notes that Bloomberg data is of the wrong duration and of the wrong credit rating, and needs manipulation to attempt to make it fit the need.

Using the APT bonds is not appropriate, as the credit rating level is incorrect, and much of APT revenue is from non-regulated sources, whereas the electricity networks are all regulated.. This means that APT is not a business of similar "...nature and degree of non-diversifiable risk ..." to electricity network businesses.

To take an average of these two sources to generate a DRP is not appropriate.

A more appropriate outcome is to use an approach which reflects economic efficiency, such as sourcing debt from banks, as the electricity network providers do for most of their debt.

3. Do stakeholders agree with the AER's conclusions regarding information from other sources?

The MEU does not agree with the AER conclusions. The MEU considers that the AER approach does not deliver an economically efficient setting for DRP as an efficient network provider would source the bulk of its debt from bank loans. Additionally an efficient provider would source some debt from internal sources and might obtain some debt as Australian and overseas bonds, although (because of the paucity of similar corporate bonds) this is not a preferred option by most electricity network businesses.

As most of the networks are government owned, much of the debt used by electricity networks is effectively sourced from bank debt and government bonds. The DRP on these government bonds is readily calculable for both duration and credit rating.

4. Are there other sources of relevant information the AER has not considered above?

The MEU considers that the AER should source information of DRP from banks which are the prime lenders to electricity network businesses, and from the financial statements of electricity network providers.

Financial statements from the businesses will provide quite accurate indications of what the cost of debt is to businesses with a similar nature and non-diversifiable risk. If the AER uses the outcomes from analysing the financial statements of all the electricity network businesses, it will have a much greater population of data to work with than just the proposed two sources (Bloomberg and APT).

The approach of using data from multiple network sources has some similarities with the Total Factor Productivity (TFP) approach currently under review by the AEMC.

5. Do stakeholders consider it necessary to use an alternative method for estimating the DRP during days in averaging periods where APT data are not available?

The MEU considers that the approach of using a short period in time to set DRP creates the potential for excessive volatility. Just as the AER considers that a long term average for MRP is a more appropriate approach than having the MRP assessed over short periods, the MEU considers the same long term averaging for setting DRP provides a lower risk outcome for all, with consistency and certainty being key drivers for setting appropriate and cost reflective values.

If the MEU approach is used, then an answer to question 5 is not needed.

6. Do stakeholders consider there is justification for making adjustments to the APT bond data to generate information during days where bond data are not independently available?

See answer to question 5.

Appendix 1

A1.1. National Electricity Rules – excerpts

Weighted average cost of capital
6.5.2(b) The rate of return for a *Distribution Network Service Provider* for a *regulatory control period* is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the *distribution* business of the provider and must be calculated as a nominal post-tax *weighted average cost of capital* (*WACC*) in accordance with the following formula:

$$WACC = k_e \frac{E}{V} + k_d \frac{D}{V}$$

Where:

kd is the return on debt and is calculated as:
rf + DRP
where:
rf is the nominal risk free rate for the *regulatory control period* determined in accordance with paragraph (c);
DRP is the debt risk premium for the *regulatory control period* determined in accordance with paragraph (e);

Meaning of nominal risk free rate
6.5.2 (c) The nominal risk free rate for a *regulatory control period* is (unless some different provision is made by a relevant *statement of regulatory intent*) the rate determined for that *regulatory control period* by the *AER* on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using:

(1) the indicative mid rates published by the Reserve Bank of Australia; and
(2) a period of time which is either:

(i) a period (**the agreed period**) proposed by the relevant *Distribution Network Service Provider*, and agreed by the *AER* (such agreement is not to be unreasonably withheld); or
(ii) a period specified by the *AER*, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the *AER* under subparagraph (i),

and, for the purposes of subparagraph (i):

(iii) the start date and end date for the agreed period may be kept confidential, but only until the expiration of the agreed period; and

(iv) the *AER* must notify the *Distribution Network Service Provider* whether or not it agrees with the proposed period within 30 *business days* of the date of submission of the *building block proposal*.

6.5.2 (d) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in paragraph (c)(2), the *AER* must (unless some different provision is made by a relevant *statement of regulatory intent*) determine the nominal risk free rate for the *regulatory control period* by interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

Meaning of debt risk premium

6.5.2(e) The debt risk premium for a *regulatory control period* is the premium determined for that *regulatory control period* by the *AER* as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.

Review of rate of return

6.5.4 (e) In undertaking a review, the *AER* must have regard to:

(1) the need for the rate of return calculated for the purposes of clause 6.5.2(b) to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing *standard control services*; and

(2) the need for the return on debt to reflect the current cost of borrowings for comparable debt; and

(3) the need for the credit rating levels or the values attributable to, or the methods of calculating, the parameters referred to in paragraph (d) that vary according to the efficiency of the *Distribution Network Service Provider* to be based on a benchmark efficient *Distribution Network Service Provider*; and

(4) where the credit rating levels or the values attributable to, or the method of calculating, parameters referred to in paragraph (d) cannot be determined with certainty:

(i) the need to achieve an outcome that is consistent with the *national electricity objective*; and

(ii) the need for persuasive evidence before adopting a credit rating level or a value for, or a method of calculating, that parameter that differs from the credit rating level, value or the method of calculation that has previously been adopted for it.

A1.2 Interpretation of efficiency in NER

Second Reading Speech on NEL 2005[25]

"The market objective is an economic concept and should be interpreted as such. For example, **investment in and use of electricity services will be efficient when services are supplied in the long run at least cost**, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.
The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised." (emphasis added)

[25] Hansard SA HOUSE OF ASSEMBLY Wednesday 9 February 2005 page 1452

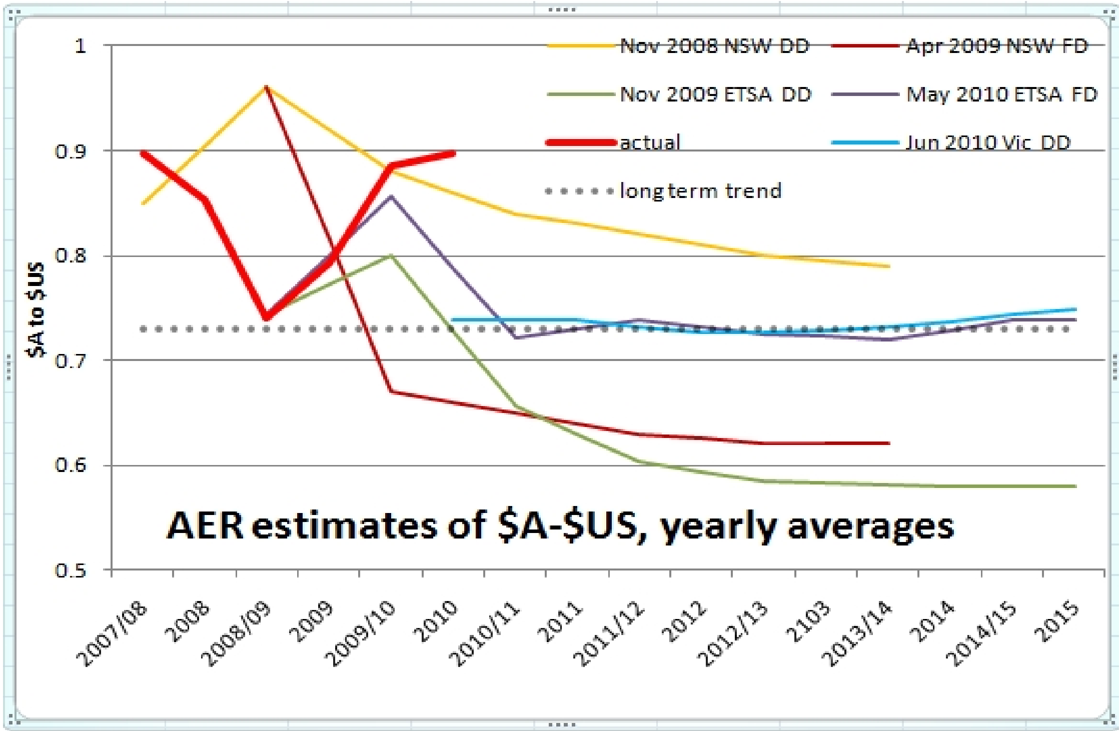
Appendix 2 –
A2. Problems with forecast variability
Example: US to Australian dollar exchange rates

The MEU has assessed the negative impacts arising from the AER approach to setting adjustments to forecast opex and capex to reflect potential moves in materials and labour costs.

Prior to 2007, regulators set opex and capex and assumed that future movements in the costs of material and labour would be accommodated by the application of inflation as measured by the consumer price index (CPI). In an attempt to be more accurate in ensuring forecast amounts would reflect actual future costs, the AER has introduced a methodology which forecasts future movements in material and labour indices.

The only certainty about these forecasts is that they will be wrong.

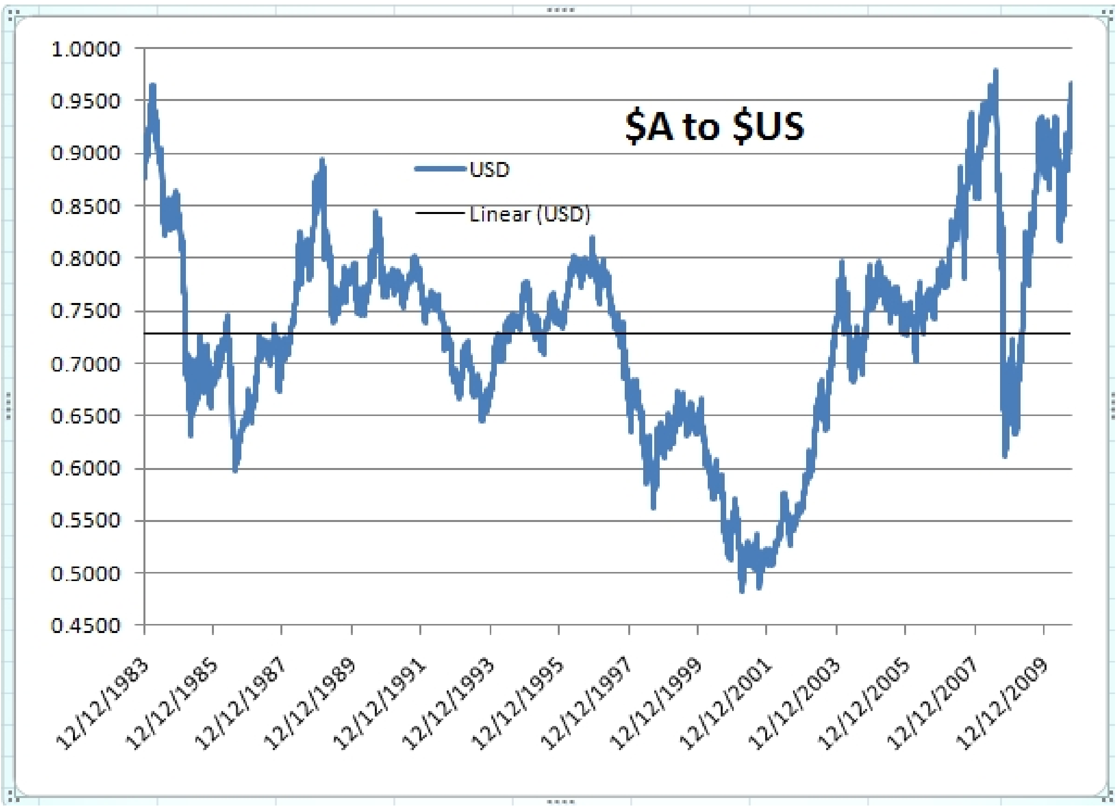
To exemplify the MEU concern, it points to the issue of exchange rate variation. In each regulatory decision the AER has proposed adjustments to material costs which are forecast in $US, such as oil, steel, zinc and copper. The following graph plots the actual movement in the $US and the $A against the forecasts used by the AER in various draft and final decisions. This shows that there has been significant error between the forecasts and the actual movement to date, and massive variation in the forecasts.



Source: AER decisions

The long term trend for the exchange rate is the linear calculation based on the historical movements in the $A since it was floated in 1983. This is shown in the next graph.

This shows that the longest period the $A has been below $US0.65 was just over 3 years, but the AER considered that this could happen for a longer period (ETSA DD and NSW FD) i the current 5 year outlook period. In fact earlier forecasts by the AER of what the exchange rate would be now were about 0.65, whereas in actuality it is approaching parity.



Source: RBA

The purpose of this example, is not to deride the AER ability to forecast, but to highlight that in attempting to be more accurate and accommodate future changes, the outcome is exactly the opposite – that greater error is introduced by attempting to be more accurate. Because of this the MEU considers that greater certainty and consistency is achieved by using longer term averages as the basis for inflation, rather than attempting to extrapolate from observations set in a short time frame.

Appendix B

APA **COMPANY ANNOUNCEMENT**
30 June 2006

BONAPARTE GAS PIPELINE GAS TRANSPORTATION AGREEMENT SIGNED

The Australian Pipeline Trust (APA) will now proceed with developing its next major greenfields pipeline project with the signing today of a $400 million Gas Transportation Agreement (GTA) between APA and PWC.

The signing of this GTA follows on from the 16 May 2006 APA announcement that it had entered into a Heads of Agreement (HOA) with the Northern Territory Government and Power and Water Corporation (PWC) which established the framework for the development by APA of a new gas pipeline in the Northern Territory.

The term of the GTA is 25 years, commencing 1 January 2009 and commits APA to develop the Bonaparte Gas Pipeline (BGP) for the transportation of gas from Eni's on-shore gas plant to be built at Wadeye, to the Amadeus Basin to Darwin Pipeline (ABDP). Based on preliminary work by APA, the BGP will follow a route of approximately 277km from Wadeye to connect into the ABDP approximately 150 kms south of Darwin, and will be initially capable of delivering approximately 30 PJ/year. APA has commenced route selection, land access and preliminary engineering activities for the pipeline and is working with PWC to progress these activities to meet the 1 January 2009 first gas date.

APA Chief Executive Officer, Mick McCormack, said: "This agreement commits APA to the construction of this major new pipeline and is an important step in realising APA's long-term vision of bringing northern gas into Australia.

"It is particularly pleasing to be building on our long history in the Northern Territory and continues our commitment to support the growing energy requirements of the Territory through our existing ownership interest in NT Gas, the operator of the ABDP. We look forward to working with the Northern Territory Government and PWC in getting on with what we do well – and developing this pipeline for the benefit of the Territory."