



28th April 2010

Mr Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Dear Mike,

AER Draft Decision on the Access Arrangements to be applied to Jemena Gas Networks in the period from 1 July 2010 to 30 June 2015

The Energy Users Association of Australia (EUAA) takes this opportunity to provide a submission to the Australian Energy Regulator (AER) on the AER's draft decision on the access arrangement proposal from Jemena Gas Networks for the period 2010-2015.

We welcome the reductions applied to the capex and opex components of Jemena Gas Networks' proposal. We do however have concerns that the reductions still did not go far enough given that the basis for the reductions was a very rudimentary historical analysis. We note that enough data was available from Jemena to use benchmarking, which may see a further reduction applied. We also welcome the removal of several proposed pass-through's but are still concerned about the remaining allowed pass-through's, in particular those relating to Unaccounted-for-Gas.

Finally we ask that the AER provide further information pertaining to its calculation of the new parameters of the Capacity-First Response tariff class, as these have significant impacts on users.

Yours sincerely,

A handwritten signature in black ink, appearing to read 'Roman Domanski'.

Roman Domanski
Executive Director



**Submission to the Australian Energy Regulator on its Draft
Decision on the Access Arrangements to be applied to Jemena
Gas Networks in the period from 1 July 2010 to 30 June 2015**

April 2010

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Executive Summary

The AER is reviewing the 2010-2015 Access Arrangement proposal from Jemena Gas Networks, the natural gas distribution company that operates the gas distribution network servicing the vast majority of NSW gas customers. The AER's draft decision results in a nominal increase in gas distribution charges of 23% by 2015, and in significant changes in tariff structure. The new tariff structure results in reduced cost reflectivity due to smoothing of the trunk mains pipelines transporting gas from the transmission receipt points around Sydney to Newcastle. This translates into significant tariff rebalancing between customers along that trunk main. These matters are of concern to the EUAA and its members.

Additionally, the AER has allowed a capacity first-response tariff, which, while providing a discount as an incentive for users to curtail their load, would impose an additional cost on users not able to respond. We outline why we believe the approach taken by Jemena and the AER needs further justification as neither have set out a clear cost-benefit arguments for the increased costs, and no information was provided at what this increased cost would be.

In the area of expenditures, the AER has made reductions to the capex and opex components of Jemena's expenditures of 28% and 7% respectively, bringing the expenditures down to 3% and 8% below current period levels. This outcome gives users a degree of comfort that the costs they will pay bear a clear relationship to historic levels.

However we note that the capex allowed was not thoroughly justified by the AER as they were only able to fall back on referring to historical expenditures, while foregoing the opportunity to apply benchmarking as applied by regulators in the UK. In this submission we suggest an approach to benchmarking which could be performed using data provided by Jemena in their access arrangement proposal.

Moreover, the draft decision still fails to contain price increases and this can be mainly attributed to a very large cost of capital at a nominal 10.2%.

The cost of capital was determined by the AER using a very high cost of debt of 9.84%, which was arrived at using an Australian benchmark rate that is far higher than the cost of debt overseas, whereas we note there is discretion allowed by the National Gas Rules. This discretion would suggest that the AER can and should set the cost of debt based on an efficient cost of debt and one that reflects the true cost of debt faced by Australian network companies. We present evidence that network companies in fact raise capital internationally and at much lower rates than the rate set by the AER.

We also identify key issues pertaining to Unaccounted-for-Gas (UAG), including the factor of 2.34%, which is higher than benchmarked by IPART for the current access arrangement and the UAG pass through mechanism. The UAG adjustment mechanism would allow Jemena to recover from users any shortfall due to either a higher than expected factor, or higher than forecast gas purchase cost. This would leave Jemena with no incentive to efficiently manage its UAG costs.

Finally we express our concern about the decision to allow carbon costs as a general pass-through. The only provides a general approach to assessing the efficiency of the costs that does not provide users with sufficient comfort that only efficient costs will be allowed.

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1 Introduction and our interest in the AER's review

This is the Energy Users Association of Australia's (EUAA) submission to the Australian Energy Regulator (AER) on its draft decision regarding the Access Arrangements to apply to the NSW gas distribution company Jemena Gas Networks (JGN), for the period 1 July 2010 to 30 June 2015. The EUAA welcomes the opportunity to make a submission to the AER.

The EUAA represents energy users throughout all of Australia and has around 100 members, many of whom are large commercial and industrial users whose commercial viability is important to Australia's economy. Several of our large members are customers of Jemena Gas Networks and are impacted by the AER's draft determination.

While we welcome the reduction in capital and operating expenditures, there are still remaining price increases of an average 23% over the access arrangement period that appear to be driven mainly by the AER's approach to setting the cost of debt which is, in our view inappropriate and leads to unnecessary price increases. This is the case particularly for Demand tariff users who do not contribute in any way to the growth requirements of the network infrastructure.

Additionally, there are several other issues of concern to energy users that we discuss in the submission.

This submission is laid-out as follows:

- Section 2 examines the impact of the AER's draft decision on prices.
- Section 3 comments on the implications of the AER's energy forecast decision.
- Section 4 comments on the AER's decision on capital expenditures.
- Section 5 comments on aspects of the AER's decision on operating expenditures.
- Section 6 comments on the determination of the rate of return and cost of debt.
- Section 7 comments on the pass-throughs allowed by the AER.

2 AER Decision on Jemena's Proposed Price Increases and Changes in Tariff Structure

In this section we comment on the impacts of the AER's draft decision on end user prices and the proposed changes to Jemena's tariff structure. In addressing the tariff structure issues we discuss our views on the proposed *Demand First Response* tariff, the treatment of the trunk mains costs, which results in price increases for some users, and the AER's decision on the *Legacy Tariffs* category.

2.1 Average end user price impact

The AER's decisions on capital and operating expenditures, as well the rate of return; translate into revenue and therefore pricing impacts on gas users. While the AER decided to reduce Jemena's capital and operating expenditures to below their actual current period expenditure, the revenue and pricing reduction that would result has been offset by a higher nominal rate of return of 10.19% versus the current period's 9.5%. The net result of the AER's overall decision is a significant 5-year compounded nominal price increase of 23%, which equate to a 9% real increase (based on the AER's assumed rate of inflation). This is made up of a 3.7% nominal increase in the first year, followed by 4.4% in the four subsequent years.

2.2 Capacity first response tariff

This section first outlines our views on the economic merits of Jemena's proposed *Capacity First Response* tariff and its structure, and second, assesses its impacts on tariff rates for Demand customers not able to take advantage of it.

As part of their revised tariff structure, Jemena has proposed a new demand curtailment tariff class for the Demand customer segment, which they call the "Capacity First Response" class. This tariff class mirrors their new standard tariffs for Demand customers whereby customers opting to take up a tariff in this class will be able to benefit by receiving a discounted rate in exchange for non-firm capacity. That is, the customers must be willing to turn down their consumption upon request from Jemena.

The *Capacity First Response* tariff class, as proposed by Jemena and approved in a modified form by the AER, results in potential savings to some users, namely those able to opt for the first response tariff, and increased costs to others who are unable to take up the option, either for operational or cost reasons.

An initiative such as this is generally welcome and we would support it if there were of demonstrated economic benefit to users. However, in our view the costs and benefits related to this initiative have not been adequately substantiated.

Specifically, we would like to know how the additional costs borne by users are offset by the benefits. In fact, ideally one would expect that the costs should be more than offset by a combination of cost savings to user, or some other financial benefits, when considered over an appropriate time horizon.

In fact, some benefit clearly accrues to Jemena, as they themselves state in appendix 15.3 (p.12) of the Access Arrangement:

“This discount reflects the benefit of avoided opex in the event of a network incident, as well as the benefit of greater certainty to managed demand to avoid a network incident.”

This benefit would presumably translate into some longer-term benefit to users but the quantum of this benefit does not appear to be stated anywhere. We would like to have these benefits clearly stated. In fact, we consider that the situation is currently such that neither the additional costs to users, nor the counterweighing benefits, have been demonstrated.

Jemena’s proposal offered eligible users a discount of 50% below the standard demand tariff rate and they forecast that the number of customers taking up this offer would equate to 43% of the total volume in the Demand Customer segment. This forecast volume is critically important since under proposal by Jemena, the number, and size of customers that choose to take up this option cannot affect the total amount of revenue collected by Jemena, which is arrived at independently based on the Post Tax Revenue Model (PTRM). Hence, there is a direct relationship between the forecast uptake volume and the standard (or non-discounted) tariffs. That is, the higher the forecast uptake volume multiplied by the discount, the greater the standard tariff rates need to be to ensure the recovery of the allowed revenues. Hence, there is a significant risk of over-recovery of revenues if the uptake falls short of the forecast. It is therefore important that the uptake rate forecast be robust and clearly justified.

Based on advice from their consultant, ACIL Tasman, the AER concluded that a take-up rate is unrealistic. The AER then formed the view that a more reasonable forecast would be set at half of the rate assumed by Jemena, or around 22%. Furthermore, the AER has determined that the discount proposed is unreasonable and must be reduced to 25%. Both these decisions have a downward impact on the standard tariff rates and are a welcome indication the AER recognises the adverse impact of this scheme on users not able to participate. While these reductions appear significant, it is not clear if they adequately reflect the potential uptake as the methodology and underlying assumptions that the AER used to arrive at these numbers has not been reported. We suggest that, in order for users to accept the AER’s decision, it is important that this information be provided.

We note that partial information about the impacts of the scheme is available through the forecast of the take-up rate provided by Jemena, which is stated to correspond to 43% of total volume of gas sold in the Demand customer segment. Jemena stated that they arrived at this forecast based on the assumption that all their larger customers with a chargeable demand greater than 1,800GJ will take up the above tariff. However, we note that previous attempts to introduce similar types of arrangements have not met with success at this level. In fact, the take up rates for the New South Wales Government’s gas contingency scheme and United Energy’s peak demand tariffs were far more modest.

In conclusion, there are several key pieces of information that users need in order to have the comfort that the numbers determined regarding the new tariff have a robust basis and that the scheme is of longer-term benefit to them. These are:

1. A comprehensive cost-benefit analysis of the *Capacity First Response* tariff proposal;
2. A justification for the assumed take-up rate forecast by the AER; and
3. The additional cost imposed on non-participating users.

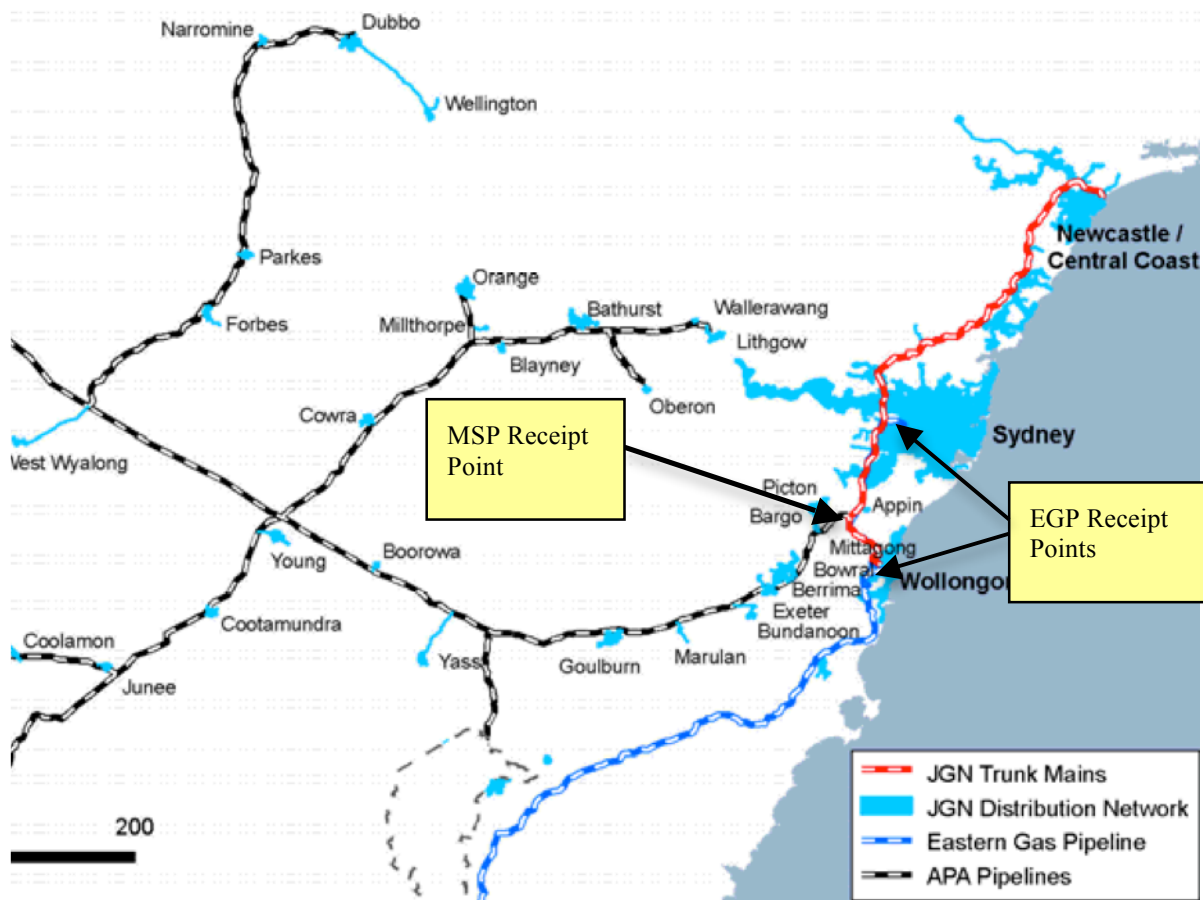
Once this information is provided, users can make an informed judgement as to the merits of this proposal.

2.3 Pricing impacts and cost reflectivity of merging of trunk costs into demand tariffs

In their Access Arrangement proposal, Jemena Gas Networks outlined a new tariff structure for demand customers (previously termed “contract” customers) that would blend the costs and revenues associated with the Wilton-Newcastle and Wilton-Wollongong Trunk Main into the rest of the demand tariffs. This means the elimination of the seven trunk pricing zones that exist under the current arrangement for both Demand (contract) and Volume Customers. Jemena Gas Networks key justification for the proposed change is the need for the tariff structure to adapt to the forthcoming implementation of the Short Term Trading Market (STTM) and the introduction of the Sydney pricing hub. Jemena cite, as an additional justification, savings to both themselves and to users inherent in the administrative benefits of a simplified charging structure. As they have not quantified these savings in the proposal it is difficult to assess their merit.

The existing tariff structure has a separate Trunk Main charge based on seven trunk pricing zones, and this charge increases with increasing distance from the receipt point at Wilton for the Sydney to Moomba gas pipeline (SMP), and at Horsley Park and Port Kembla for the Eastern Gas pipeline (EGP). This results in Sydney and Wollongong users paying a lower trunk charge than Newcastle users, who are at the farthest end of the Trunk Main. This can be seen in Figure 1.

Figure 1: Jemena's pipeline network, from JGN AA Information Aug 2009



The AER proposes to approve the tariff methodology and structure which results in the following impacts on users:

- Users in the Sydney and Wollongong areas are facing increases in their overall network charges of around 10%.
- Users in the Newcastle area are facing decreases in their network charges of around 10%.

While significantly lower than the impacts in Jemena's proposals (around to +50%/-50%), these are still substantial changes and need to be justified if they are to be accepted by end users. Furthermore, the proposed trunk pricing structure is quite significant and may, if accepted, continue to adversely impact the price reflectivity of the tariffs if large increases in capital expenditure occur in the 2015-2020 access arrangement period. Below we outline our understanding of the methodology used to develop the pricing structure and provide our views on it.

The AER described the methodology thus:

“As outlined, the blending of the trunk tariff is based on deriving a notional trunk charge for each network tariff block. The notional trunk charge is based on 2009–10 trunk revenues and quantities for demand users across the coastal part of the network divided into the five tranches or blocks of gas consumed. The outcome of this estimation process is that the trunk charge is not uniform for each tranche or block of gas. It is also true that the estimation process results in a higher notional tariff charged for the tranche with the largest gas use.”

We interpret this to mean that:

1. The trunk costs will be allocated purely based on usage rather than location along the trunk as they are now.
2. The component of the trunk cost increases with increasing usage, implying a type of block tariff approach. Further information about this approach would help users assess the validity of this approach if they are to accept it and support it in the future.

The removal of a locational price signal is concerning as it runs counter to the principle of cost reflective pricing. We address the AER's justification for this further on in this section.

The AER has asserted that the new pricing structure is consistent with the National Gas Rules, and in particular, under Rule 94(2):

*“A tariff class must be constituted with regard to:
(a) the need to group customers for reference services together on an economically efficient basis; and
(b) the need to avoid unnecessary transaction costs.”*

This assessment was justified by the AER according to the following arguments:

1. Under the new arrangement, users in zones with the highest demand network tariffs will still be the zones with the highest demand network tariff.

2. In response to submissions made to the AER on Jemena's proposals, which stated that the Tariffs must be cost reflective, the AER argued: "*The NGR does not require that each tariff reflects the actual cost of providing the reference service to each user.*"
3. The rules only require that tariffs be set between the bounds of stand-alone and avoidable costs.
4. The reduction in administrative transaction costs outweighs the benefits of cost reflectivity of a separate and zone based trunk charge.
5. The need for "uniform hub pricing", due to the start of AEMO's short term trading market (STTM).

We are concerned that the AER's should correctly and consistently apply the Rules. The issue at hand is whether the new pricing structure sufficiently meets the need for economically efficient and cost reflective pricing. We address the AER's above five points here:

1. It is not clear why the AER believe consistency regarding which zones have the highest/lowest tariffs justifies the removal of the zonal pricing structure for the Trunk Main.
2. The AER's response to the submissions expressing concerns about cost reflectivity needs to be clarified. Whilst tariffs can never exactly reflect the cost of service to each customer, efficient pricing implies the need to get as close to this as possible taking into account available information and administrative transaction costs. It is not clear why the AER believe that this point has been attained?
3. We would argue that the AER's assertion that their decision is justified by the Rules' requirement regarding the basis of the tariff bounds being avoidable and standalone costs is not helpful. The gap between the two bounds is so large as to allow almost any tariff structure and further care must be taken by the AER in order to also address Rule 94(s) above. For an example of the size of the gap we draw attention to Table 12.1 in the AER's draft decision, which sets out the tariff bounds for the 11 geographic pricing zones. The problem is apparent if we look at the case of a user in Sydney Zone DC – 1: the avoidable costs are estimated at \$326,000, as compared with stand-alone costs of \$39.2 million.
4. The stated reason is not consistent with Rule 94(2)(b) since the tariff structure is allowed to (appropriately) retain much of its previous complexity through:
 - a. The 11 geographical pricing zones DC-1 to DC-11; and
 - b. A 5-tranche declining block-tariff approach.

It is difficult to imagine that the administrative impost of another 7-zone components would not pose a large additional cost.

5. Our assessment of the design of the Short Term Trading Market is that it operates at the level of wholesale gas pricing and transmission by creating a single notional hub to which gas transmission pipelines deliver gas. This need not have any impact on the cost reflectivity of distribution pricing, as it was designed to make sure wholesale gas purchasers are not disadvantaged with respect to which injection point and which transmission line the gas is shipped on.

Based on our discussion above, we believe Jemena and the AER have failed to sufficiently justify the incorporation of the trunk costs into the Demand Capacity tariff rates and in making this decision did not apply the Gas Rules appropriately or consistently.

2.4 Legacy services

Jemena clearly intends for all customers to transition to their new proposed tariff structure, and in order to achieve this they have proposed to classify the existing tariffs as “legacy services”. Additionally, they proposed to increase the price of their legacy services over and above the increases required by the increases in regulated revenues. The AER noted that this so called “premium” was proposed to be 5-6% on top of the proposed first year (P₀) increase of 34%. Jemena had justified this premium based on the claim that they will incur additional administrative costs in retaining these tariffs. The AER has assessed the proposal and justifiably, in our view, rejected the proposed premium citing Jemena’s inability to provide robust quantitative analysis to support their proposition.

Additionally, the AER also required the Access Arrangement to be amended so that the legacy services are classified as reference services. We would like to draw the AER’s attention to the fact that this creates the potential for confusion, as reference services are those that can be chosen by any customer in the market. While the class of legacy tariffs is clearly intended as a transitional measure until all customers transition to new tariffs at the end of existing gas contracts, the possibility remains that some customers may request to select existing tariffs when entering into new contracts. This would clearly be an unintended outcome and the AER needs to identify a way to remove any potential confusion regarding tariff selection.

3 Demand forecasts

In their proposal, Jemena Gas Networks have put forward energy sales forecasts that, over the 5-year period, are 2.1% lower (on average) than during the current Access Arrangement period. These were based on actual data available up to June 2009 and a forecast was produced for the financial years 2010-2015. The reduction in demand was driven by three key categories. The first category relates to assumptions about the impacts of a range of government policies related to energy and energy efficiency, the second relates to assumptions around changes in the number of gas appliances, primarily those used for water and space heating, and the third relates to impacts of the decline in economic activity in NSW.

The first two categories were assumed to impact only the volume (small) customer segment currently accounting for around 35% of the annual usage, which is 95-100 PJ/annum. The third driver category used to justify the reduction in demand forecast, was the impact of declining economic activity in NSW due to the Global Financial Crisis and other factors. Jemena forecast their demand customer segment's load for 2009-10 to be around 60 PJ/annum, or around 4 PJ below their 5-year average for 2005-2009.

Based on a review of the draft determination and the report by ACIL Tasman, the AER's consultant, we agree with the AER's view on the impact of the above factors on the forecast. In particular, ACIL advised that the impact of the following policies, would be minor:

- The CPRS and RET.
- The Building Sustainability Index (BASIX) certification system for new NSW homes.
- The program to review and standardise energy labelling of gas appliances followed with the development of Minimum Efficiency Performance Standards (MEPS) for new gas appliances.
- The increased penetration of energy efficient showerheads.
- The effective banning of electric resistance hot water appliances from 2012.
- The Commonwealth stimulus package with subsidies towards home insulation.
- Other new policies or developments, such as the new NEET policy of the NSW Government and the RET scheme.

Additionally, ACIL's view was that Jemena's projected volume customer demand due to the following assumptions about the changes in the mix of gas versus electric and other energy appliances was not justifiable:

- The ongoing negative impact of high sales of reverse cycle air conditioning equipment.
- Replacement of electric water heaters with solar-electric and heat-pumps.

Specifically, ACIL has revised the customer segment volume forecast upwards resulting in the 2015 demand being projected to be 38.2PJ/annum versus Jemena's forecast of 34.8 PJ/annum, an increase of 10%.

In the case of the demand customer segment, ACIL judged the impacts of the economic factors to be overstated.

Additionally, Jemena provided to the AER and ACIL more up to date demand figures for the 6 months to 31st of December 2009, which implied a higher consumption than forecast in their proposal for the financial year 2009-10 of 64 PJ/annum versus the 60 PJ/annum put forward in Jemena's proposal. This validated ACIL's concern that the forecast step reduction of 4 PJ

was not going to be realised.

ACIL then provided a 5-year trend based forecast, which was significantly higher than that in Jemena's proposal and which also accounted for weather related impacts on the historical demand. ACIL's revised forecast for the demand customer segment resulted in a figure of 67.8 PJ/annum segment, versus Jemena's forecast of 62.9 PJ/annum, by the end of the next access arrangement period in 2015. This amounts to an increase of 4.8% in the average annual demand over the current 5-year period.

We consider the analysis performed by ACIL and the AER to be robust and agree that the revised forecasts (produced by ACIL) and applied by the AER in its Draft Determination are a sounder basis on which to set Jemena's revenues and prices for the 2010-2015 Access Arrangement period.

4 Capital expenditures

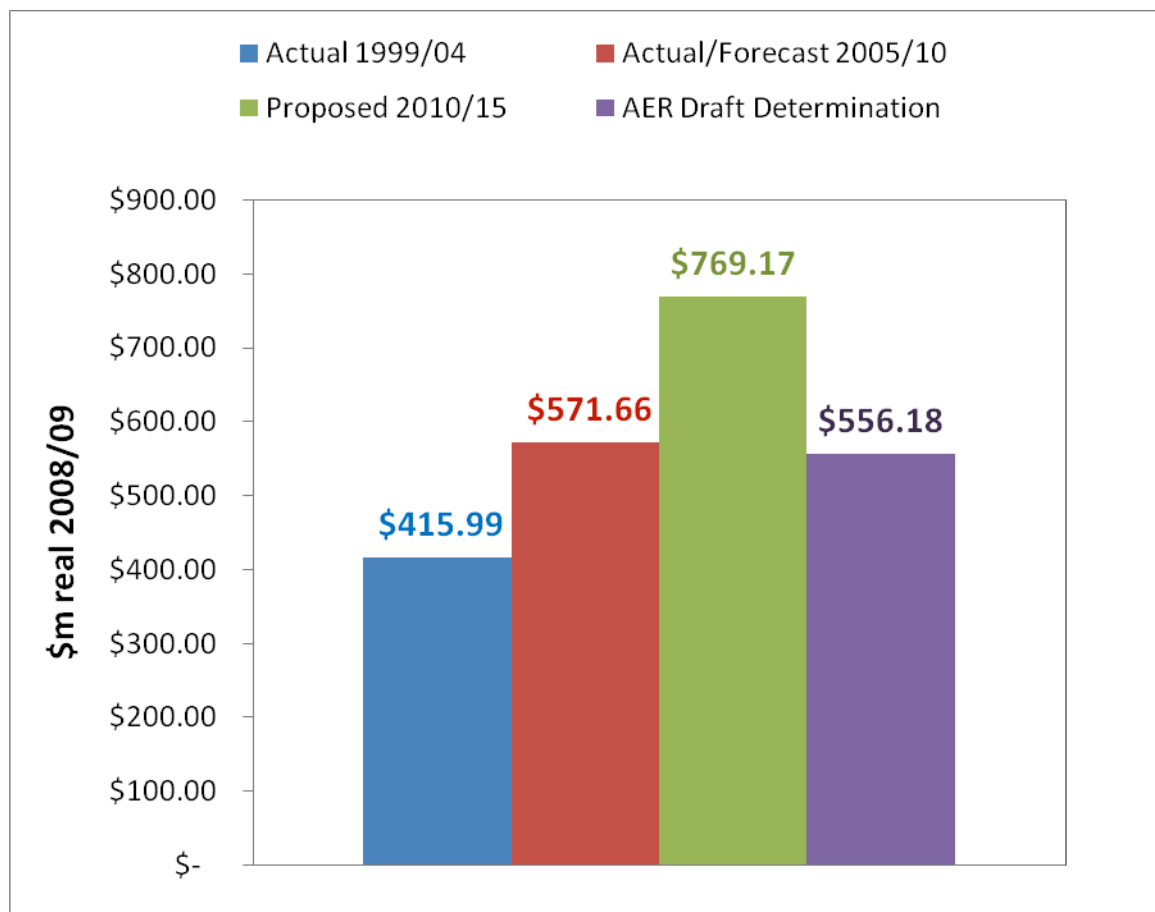
In their access arrangement proposal, Jemena requested a capital expenditure allowance of \$775.9m (\$2008/09). This would be a 35% real increase on the estimated actual outcome for the current period of 571.6m (\$'2008/09). As such, it is significant and therefore deserving of close attention by the AER.

4.1 Reduction in capex allowance

The AER in their draft determination applied a reduction of around 28% below the proposed capex resulting in an allowance of \$556.18m (\$'2008/09), which was slightly (2.7%) below the estimated actual expenditure for the current 2005-2010 access arrangement period. The capex expenditures are set out in

Figure 2 below for each regulatory period from 1994 to 2015 and include Jemena's proposal and the AER draft determination for the coming period.

Figure 2: Jemena's capex by regulatory period from 1999 to 2015



The AER based their decision on advice from Wilson Cook and Co. Ltd whom they engaged to assess Jemena's proposal. Wilson Cook categorically stated that they were not satisfied that the proposed expenditures were efficient, while the scope of works underlying the

proposal was, in fact, prudent. They cited lack of information to help them determine that the expenditures were efficient. In fact, Wilson Cook expressed significant concern about the basis upon which the costs were provided. The following quote is noteworthy¹:

"Again, a common theme in all the expenditure categories reported in this section is the lack of information available on which to verify the scope, necessity, timing and optimality of the expenditure foreseen. In most instances, the planned quantities of routine work were not provided either, making it impossible to verify unit rates.

...

However, in no case have we been able to attest to the cost efficiency of the expenditure because of the lack of information on the details, volumes and costs of planned work."

Wilson Cook's comments clearly indicate substantial concerns with the level of proposed expenditures and their efficiency. The AER has applied reductions to capex based on these concerns. However, we are concerned that the level of reduction applied by the AER was not sufficiently substantiated by analysis. The AER has this to say about their reasons for approving the \$556.2m (which we quote in \$2008/09 constant currency for comparison purposes):

"The AER approves a baseline level of expenditure based on historical levels of capital expenditure for the majority of the proposed system reinforcement, renewal and replacement capital expenditure for the access arrangement period. This approach is adopted because there is an absence of information to support the higher proposed level of expenditure, and concerns that the proposed scope of work can be delivered without detailed business plans and capital programming within the proposed timeframes. Further, the AER considers that the historical capital expenditure is a good indication of the level of capital expenditure that Jemena is capable of delivering in the access arrangement period."

This approach is not justified or consistent with the National Gas Rules (NGR). Historical expenditure on its own is no indicator of efficiency of expenditures. Additionally, there is some ambiguity about what historical period the AER used to "benchmark" the expenditure. Given that the amount they approved is close to the current period actual expenditure, it appears that they used only 2005-2010 as a basis. They have not justified this choice. If an earlier period were selected, such as 1999-2004, the allowed capex would have been much lower.

This is a significant concern for users and in view of the concern about the particular lack of substantiating information from Jemena expressed by Wilson Cook, we consider that a more robust approach is needed. It is our view that the best approach is in fact a proper application of Benchmarking, which we discuss further on in this section.

4.2 Capex benchmarking

We raised the need for benchmarking in our previous submission to the AER on Jemena's initial proposal. While the National Gas Rules, in contrast to the National Electricity Rules

¹ "Review of Expenditure of ACT & NSW Gas Distributors Jemena Gas Networks (NSW) Ltd" – Wilson Cook & Co. Ltd, Dec 2009, p70

(NER), do not explicitly call for benchmarking, it is nevertheless still valid and important to apply this regulatory tool. The lack of available information for a thorough analysis of the capex we discussed earlier, make this even more important, and information for a benchmarking of capex is clearly available, as demonstrated by Jemena's own consultants, PB Associates, in their report for Jemena forming part of the submission.

The AER had this to say in response to our submission and PB's work on benchmarking:

"The AER has considered the results of PB's benchmarking study. The AER agrees with the Wilson Cook report that such analysis has its limitations and cannot alone be used to assess whether capital expenditure complies with r. 79 of the NGR."

We disagree both with the AER's comments and those of Wilson Cook that it referred to. The work done by PB may have been limited, but was very similar to the work done by the AER itself on the Queensland and South Australian electricity distribution revenue determinations. This work was done in relation to operating expenditures but the methodology was similar, in fact, in their work for Jemena, PB went somewhat deeper by also incorporating volume throughput as an expenditure driver, following the methodology used by Ofgem in the UK for electricity distribution revenue benchmarking.

In our response to the AER's draft determinations in that process², we both identified the errors in the application of the methodology, and set out how it can be used to determine what the expenditure should be. We agree with Wilson Cook and the AER that PB's application of benchmarking, which they claimed shows Jemena's historical expenditures to be efficient, is incorrect. However we disagree with the reasoning. The problem with PB's benchmarking for Jemena was that they did not apply benchmarking correctly. They simply drew a line of best fit through the data and stated that based on this analysis Jemena compared favourably with the other operators. We deduce from their line of argument that PB is interpreting the line of best fit as indicating an efficiency trend or some kind of benchmark. Based on our work on benchmarking for electricity networks, we believe that the interpretation applied by PB is incorrect. A more appropriate application of the approach, as we outlined in our submissions on Queensland and South Australian electricity distribution determinations, would show that Jemena's proposed Capex is worse than an efficient operator's. We also caution against interpreting the following statement from PB Associates on page 17 of their report as indicating that "high-level" benchmarking is not applicable to setting capex:

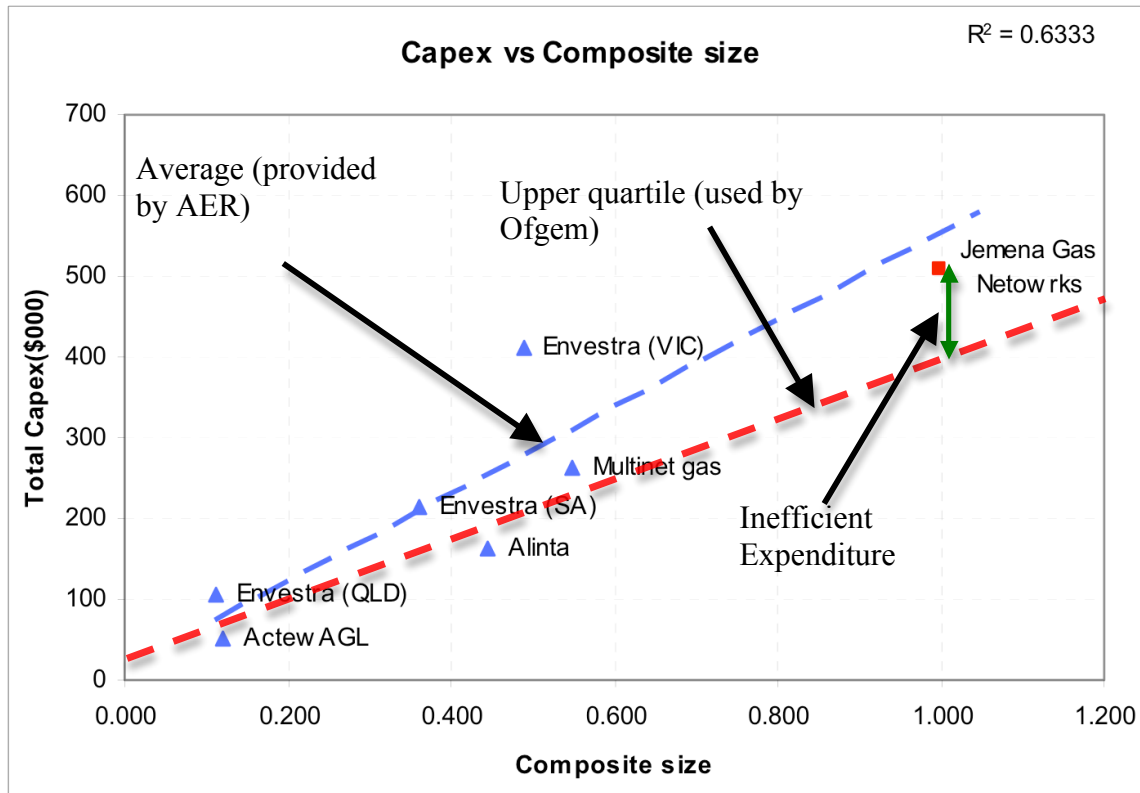
"Since high-level benchmarking of the capital expenditure does not provide an indication of the prudence of individual projects, it is not possible to determine from benchmarking alone whether each of JGN's capital expenditure project complies with rules 74 and 79."

This statement simply indicates that the prudence of a given project cannot be deduced from benchmarking, and one must not generalize from this to the validity of benchmarking in setting total network capex.

Figure 3 shows how one might go about this by defining an upper quartile boundary, which is utilized by Ofgem to benchmark and help set approved costs. We note that the Ofgem approach has had a significant impact on the setting of efficient costs. A proper benchmarking analysis of capex and opex should be carried out for Jemena.

² "Submission to the Australian Energy Regulator on its Draft Decision for the regulated revenues to be applied to Energex and Ergon Energy in the period from 1 July 2010 to 30 June 2015", EUAA, February 2010

Figure 3: An example of capex benchmarking using the chart from PB Associates



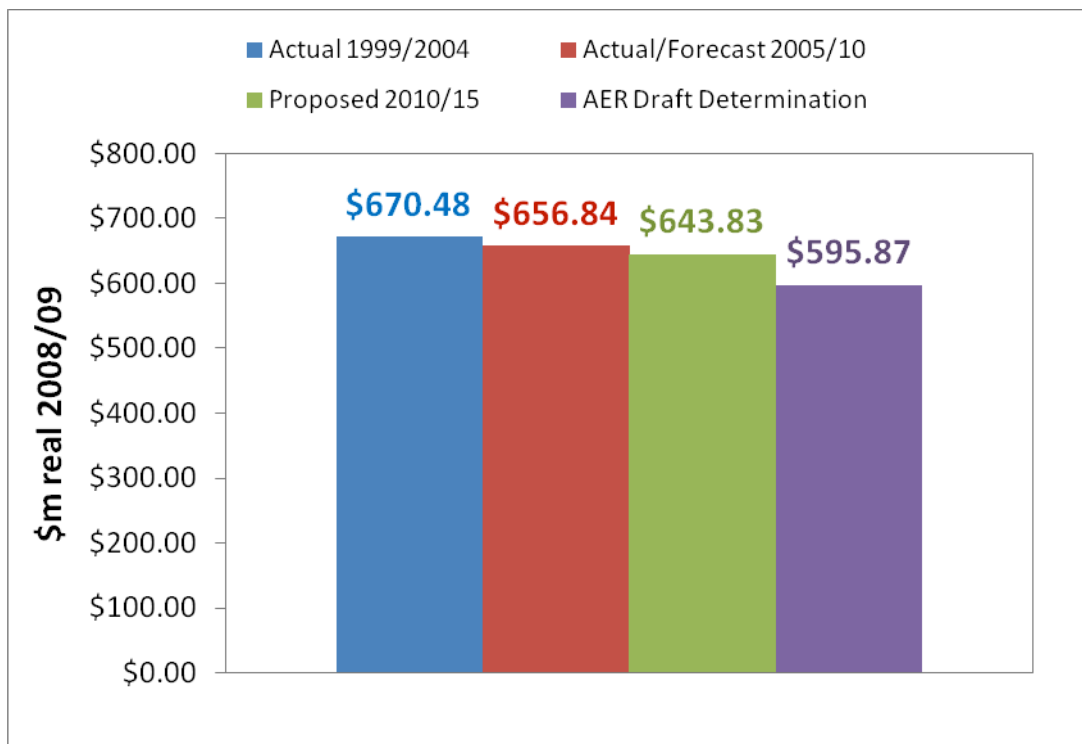
5 Operating expenditures

This section outlines our views on the impacts of the draft determination on Jemena's opex allowance. We focus on the reduction applied to the total opex and the allowance for Unaccounted for Gas (UAG).

5.1 Reductions in Opex allowance

The AER allowed a total opex of \$595.9m (\$'2008/09), a reduction of 6.6% below the proposed opex and 8.5% below the expected actual for the current access arrangement period. Figure 4 shows the current allowance against a historical trend of lower operating costs. The AER applied a reduction, which in combination with the demonstrated trend for decreasing opex since 1999 gives users a degree of comfort about the level of opex over the coming period.

Figure 4: Jemena operating expenditures from 1999 to 2015 over three periods



5.2 Unaccounted for gas (UAG) factor

The transportation of gas often results in the loss of some of the gas along the way. This component, known as Unaccounted for Gas, or UAG, needs to be made up through purchases of additional gas by the transportation company, in this case Jemena. These purchase costs make up a component of the opex and the AER allowed \$66.6m (\$2009/10), which makes up over 10% of the total opex allowance. The cost applied is based on two key assumptions:

1. Percentage of gas lost, also known as the UAG factor, which the AER set at 2.34%

2. The delivered cost of Gas, for which the AER approved \$5.5/GJ (\$'2009/10)

UAG Factor

In its proposal Jemena stated that it should be allowed a UAG factor in a range between 2.1% and 2.7%. The AER based its decision on their consultant Wilson Cook's analysis of historical UAG levels. We do not agree that this is the correct approach to setting the costs as it does not reflect efficient practice, nor does it provide an incentive to minimise this cost. We refer to IPART's determination for the current period where an initial UAG factor of 2.2% was allowed, which would decline to 2.1% by the end of the current period. Clearly, IPART was of the view that 2.1% was a level achievable and reflective of an efficient service provider. We can see no justification in either Jemena's proposal, or the AER's analysis, for a departure from that view.

Our concern about the issue of the UAG factor is compounded by the AER's decision to allow a pass-through, called the UAG Adjustment Mechanism, that appears to permit (inefficient) variations to the UAG level to be passed through to users. This is not an efficient way for Jemena to manage such costs and not does it provide them with an incentive to do so.

6 Rate of return

The AER has rejected Jemena's proposed rate of return on the grounds that their proposed methodology for determination of cost of equity, the Fama-French model, was inappropriate. We support this decision and agree that there is no merit in moving away from the use of CAPM for this purpose, which is an accepted approach amongst regulators internationally.

6.1 Cost of debt

The AER, nevertheless, allowed a high weighted average cost of capital (WACC) of 10.19% through its allowed nominal cost of debt of 9.84%. This is an unreasonably high rate and arrived at by using the approach the AER uses in setting the cost of debt for electricity network businesses. While the National Electricity Rules are quite prescriptive in how the AER is to determine this number, the National Gas Rules leave significant discretion to the regulator.

Currently, the NER requires debt costs for electricity networks to be determined based on the risk free rate and a debt risk premium calculated by "annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds". This level of prescriptiveness is not replicated in the NGR.

The NGR in rule 87(2) states that that in determining the 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.”*

We thus draw the AER's attention to the fact that Australian gas distributors should be expected to meet the majority of their debt capital requirement from the cheapest sources available, including through international bond markets, rather than just Australian bond markets, if the latter are more expensive. As such, the relevant consideration is the cost of debt for Australian utilities in international capital markets, not just Australian capital markets. There is, of course, nothing unusual about this, as the bulk of debt raised by Australia's major corporations is sourced from off shore capital markets. While for electricity this may be affected by the prescription in the Electricity Rules, there is no such explicit requirement in the Gas Rules. We therefore see good reason why the AER needs to apply a methodology that sets the cost of debt according to its most efficient source, and the NGR would not seem to also support the application of the most efficient debt benchmark.

In this regard, we note a recent capital raising by SP Ausnet (SPN) in Victoria for corporate debt in off shore capital markets. In a recent research note, Credit Suisse said that:

“We have seen a number of the Australian regulated utilities accessing attractive off shore bond issuances over the past six months, which are providing tenure longer than available in the Australian bank debt market, and more favorable rates. The Australian Energy Regulator (AER) in its draft decision for ETSA utilities proposed a debt margin of 429bps. This represents a ~280bps wind fall gain to where SPN is

currently able to issue debt.”³

A small part of this difference – perhaps around 50 basis points – may be accounted for by SPN’s A- credit rating (compared to the BBB+ used in the AER’s WACC methodology). However, the largest part of this difference is explained by the fact that debt capital is currently cheaper to access in off-shore capital markets. By setting a cost of debt in Australia based on the AER’s theoretical construction of a debt premium on top of *Australian* risk-free rates, the AER is allowing a cost of debt that is out of proportion to the price that energy utilities are actually paying.

7 Cost pass-through’s

We note that Jemena proposed a significant list of pass through events. We welcome the fact that the AER has rejected some outright, particularly the weather variation adjustment, or proposed to monitor others more closely by removing them from the Tariff Variation formula. However, we remain disappointed that a large number would still be approved. We comment on two of these specifically later in this section, namely the UAG adjustment mechanism, and the carbon cost pass through.

We do not support pass-throughs as a matter of principle and believe that they will always be asymmetric in favour of the network businesses given their information advantages. Consequently, during any Access Arrangement period, it is highly likely that only cost increases will be the subject of pass through and any cost reductions that emerge will almost certainly never be passed through.

As the National Gas Rules and the National Gas Law allow the AER significant discretion to determine pass throughs, this asymmetry ought to be recognised in the assessment of pass through arrangements.

In this context, we note that the application of economic regulation to energy networks in Australia has been founded on the principle that the outcomes ought to mimic those found in competitive markets. With regard to pass-throughs, this clearly has a limited application in competitive markets. In competitive markets, pass through only applies where costs are the result of factors outside the control of the business and then only if the business is in a position *vis-à-vis* its competitors to be able to pass through these costs. In the case of regulated businesses, this needs to be recognised by the regulator with a eye on the incentives for “strategic behaviour” by the regulated business.

7.1 UAG adjustment mechanism

The AER has allowed an UAG cost adjustment mechanism that appears to allow any variation in cost to be passed through to users. This could be a variation due to change in actual UAG volumes or gas purchase costs. It is difficult to see how this type of pass-through conforms with the intent of the National Gas Rules to incentivise operational efficiencies. Under this mechanism Jemena would have absolutely no incentive to minimise either the amount of gas lost, or the purchase cost of gas. We therefore oppose to the UAG adjustment mechanism.

³ Research note on SP Ausnet, Credit Suisse, Sydney, 19 February 2010.

7.2 Carbon costs

We welcome the AER's rejection of Jemena's proposal to include the cost of procuring carbon credits or permits as part of the opex component of the post tax revenue model. We support this for two reasons:

1. There is significant uncertainty as to the timing and form of the possible emission-trading scheme, leading to the possibility of windfall gains for Jemena in case of either a delay in the scheme or a lower carbon price outcome.
2. Jemena's proposed carbon costs were based on a carbon price forecast. Market price forecasts are difficult to validate, especially in a market that is yet to form, and their application in setting revenues is likely to favour the service provider.

As an alternative, the AER has allowed carbon costs to be captured through its own proposed "general pass-through" event. However, noting that the potential permit costs are likely to be significant (Jemena forecast around \$12m per annum for a relatively low carbon price of \$30/tonne, or around 8% of the opex), we are concerned that the AER's proposal for assessing the efficiency of the procurement of the carbon credits based on amendments 13.3 and 13.11 to the Access Arrangement, is too general to provide users with sufficient protection. We therefore ask that the AER develop a more explicit and comprehensive approach to assessing these costs, which should be transparently applied on an annual basis, in consultation with Jemena's customers. As there is some time until a volatile carbon price is likely to eventuate, the opportunity exists to properly consult on this.