NSW Gas Distribution Revenue Reset

Draft Decision by the Australian Energy Regulator on Jemena's Gas Networks Access Arrangement

A response

by

The Energy Markets Reform Forum

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Overview

The Energy Markets Reform Forum (EMRF) is a forum representing large gas and gas infrastructure users in New South Wales. The EMRF is an affiliate organization of the Major Energy Users (MEU).

This submission by the EMRF to the Australian Energy Regulator (AER) is in response to:

- the AER's Draft Decision[1] on the proposed 2015-20 gas Access Arrangement (2015-20 AA) by Jemena Gas Networks (NSW) Ltd (JGN);[2] and

- JGN's revised proposal submitted in response to the AER's Draft Decision.[3] The EMRF also provided a submission to JGN's original proposal in August 2014.[4]

Overall, the EMRF considers that the AER has fulfilled the requirements in the National Gas Rules (NGR) and the National Gas Objective (NGO), to make a decision that is in the long-term interests of gas consumers.

It is a decision that brings an end to an era of excessive regulatory allowances and profits that are substantially higher than is commensurate with the relatively low risk of the regulated businesses. The draft decision therefore establishes a new regulatory "benchmark" in which networks, including JGN, will have to strive for continuous improvement.

In this respect, the AER's draft decision on JGN is consistent with the principles it established in its draft decisions on the NSW electricity distribution networks. In effect, it has returned the regulatory allowance back to the levels seen prior to the 2010 – 2015 period (in real dollar terms).

The draft decision is also consistent with the fact that the gas market in NSW is now a mature market with limited growth opportunities. The most

[1] AER, *Draft decision, Jemena Gas Networks (NSW) Ltd, Access Arrangement 2015-20*, November, 2014.
[2] Jemena Gas Networks (NSW) Ltd, 2015-20 Access Arrangement, Response to the AER's draft decision & revised proposal, Public, February, 2015.
[3] Jemena Gas Networks (NSW) Ltd, *2015-20 Access Arrangement, Response to the AER's draft decision & revised proposal*, Public, February, 2015.
[4] EMRF, *NSW Gas Distribution Revenue Reset, A response by the Energy Markets Reform Forum*, August, 2014.

appropriate strategic response for a company in this situation is to focus on reducing costs and rationing capital to projects that have a clear cost benefit – there is limited opportunity for future growth to “take up the slack”.

Given this, the EMRF considers that the AER’s draft decision will still provide an opportunity for JGN to enjoy rewards for delivering the network services in compliance with its regulatory obligations and with a focus on prudent investment and continuous improvement.

The EMRF considers that the AER should make its final decision bearing in mind that economic regulation is, at its heart, a proxy for competition. The EMRF considers that the expenditure discipline set out in the AER’s draft determination is no more than that imposed by a competitive market – a market that JGN’s business customers face every day.

In similar vein the EMRF is concerned with JGN’s explicitly and implicit claims that the AER’s draft decision will prevent it from meeting its obligations to provide a reliable and safe gas network. This would be the case if the AER’s draft decision had cut expenditure below previous historical levels or if the gas market was expanding at a rate above historical levels.

Neither of these is the case. As noted above, the AER’s revenue determination simply puts JGN back to the same position it was before the expansionary expenditure period of the most recent regulatory period (2010 to 2015). As also noted above, JGN’s market is mature, with low growth rates in the current period and forecast for the next period – well below that seen in the years prior to this review.

In addition, the Board and senior management of JGN have a responsibility to set priorities and those priorities must be safety and reliability. The AER draft decision gives JGN some $2,477 million revenue allowance, including a capital expenditure (capex) allowance of some $916 million. It is up to the Board and senior management to ensure reliability and safety of the existing network is prioritized appropriately. Again, the prioritization of expenditure is no more than a normal business process.

Given this, it is disappointing to see that JGN has responded to the AER’s draft decision with a revised proposal that makes no significant changes to its original proposal. The EMRF, therefore, considers that much of the material provided to the AER in its original submission on the JGN initial application is still relevant and requests that the EMRF’s original submission be considered as part of its current response to the AER’s draft decision and the EMRF’s response to the JGN revised proposal.

The following sections summaries a number of the AER's key decisions and the EMRF's response. It also identifies areas that are of continued concern to the EMRF.

The AER's Draft Decision

In its Draft Decision, the AER allowed JGN a total revenue allowance of $2,477.3 million ($nominal). Based on the AER's forecast of gas usage in NSW, this revenue would result in a real decrease in the weighted average tariffs[5] of 23.4% in 2015-16, followed by real decreases in each of the subsequent four years of 2.1%.

The AER's draft decision allowance is 25.5% lower than the total revenue proposed by JGN in its initial proposal in June 2014. JGN had proposed real average price reduction of 1.6% in 2015-16 and around 0.2% in the remaining four years.

The AER's draft decision identified a number of areas where the proposed expenditure was not prudent and/or efficient. The AER therefore, made a number of "more preferable decisions" including:

- The allowed rate of return on assets – reduced from JGN's proposed 8.67% to 6.8%;

- Reduced the capital expenditure allowance by 18.7%, from $1,130.4M ($2014-15) to $916.6M ($2014-15);

- Reduced JGN's forecast operating expenditure by 1.2% from $789.3M ($2014-15) to $779.7 ($2014-15)

- Rejected JGN's demand forecasts leading to an increase in annual per customer consumption for residential and small business customers;

- Accepted most aspects of JGN's proposals on tariff classification, cost and revenue allocation and tariff structures

Of these factors, the most significant factor impacting on the total revenue for the next period is the difference between the rate of return proposed by JGN and the AER's allowed rate of return. The reduction in capital expenditure will also have long term cost benefits for consumers through its impact on the future regulatory asset base (RAB).

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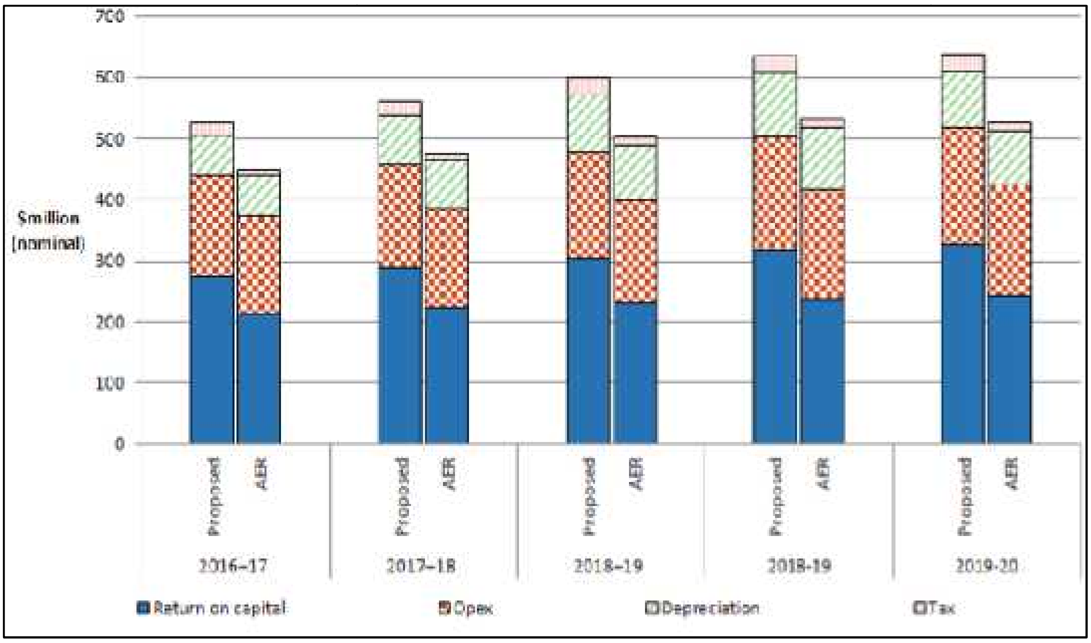
[5] Jemena is subject to an average maximum price cap form of control for its gas networks in NSW.

Figure 1: AER's draft decision and JGN's proposed building block revenue (unsmoothed) ($million, nominal)



Source: AER, *Draft Decision Jemena Gas Networks*, November 2014, Figure 7-2, p 25

JGN's response to the AER's draft decision

In its revised proposal, JGN stated that it did not accept the AER's Draft Decision. JGN has four fundamental objections to the AER's draft decision. They are:

- that the AER has not appreciated the changes in the NSW energy market;
- the AER has not engaged consumers directly in its decisions, unlike JGN. JGN claims that consumers have supported its proposed expenditures;
- the AER's approach to assessing the rate of return does not provide sufficient return on investment and will lead to under-investment in the network; and
- the AER's decisions included "errors of fact and logic" and did not reflect the requirements in the NGR and the National Gas Law (NGL) including the revenue and pricing principles in the NGL.

In its revised proposal, JGN has, therefore, largely restated the expenditure proposals set out in its original proposal. However, it has included a lower cost of capital (as a result of lower market interest rates since the draft decision) and this will result in real reductions in average network prices that are greater than those initially proposed by JGN.

Average price impacts of JGN's proposal & AER's Draft Decision

Table 1 below summarises the average price impacts of JGN's initial proposal, the AER's draft decision and JGN's revised proposal. It should be noted that:

- Within the overall price path, JGN is proposing quite significant reductions for Tariff V customers and a nominal price increase for Tariff D customers. This is discussed in Section 7 of this submission.

- Average price movements depend on the total revenue and total volumes forecast. The AER has forecast higher gas consumption than JGN. All other things being equal, a higher gas demand forecast will lead to lower average prices under the maximum price cap form of control.

Table 1: Summary of changes in JGN's average real network prices ("X-factor" (Note 1))

	JGN original proposal June 2014 (1) %	**AER Draft Decision Nov 2014 (2) %**	**JGN Revised proposal Feb 2015 (3) %**
2015-16	4.0	23.4	6.50
2016-17 to 2018-2019	2.7	2.1	8.24
2019-20	2.7	2.1	(1.84)

Notes:

(1) The X factor arises from the revenue control formula of (CPI-X). A positive X factor means a real price decrease, a negative X factor means a real price increase.
(2) JGN, 2015-20 Access Arrangement information – Public, Table 12-2, p 105.
(3) AER, Draft Decision, p 8.
(4) JGN: Revised proposal, Table 10-4, p 112.

While JGN's revised proposal results in greater reductions in average prices than its original proposal, this reduction is largely a reflection of the very significant decline in interest rates since June 2014.

The EMRF considers, therefore, that JGN's revised proposal does not adequately address the fundamental issues raised by the AER and by consumer representatives including the EMRF. EMRF does not accept that JGN's revised proposal meets the objective of ensuring the lowest sustainable cost of delivering safe, reliable and affordable services to JGN's gas customers.

The EMRF's specific concerns are summarized below noting that these comments in this submission should be read in conjunction with the EMRF's original submission given the limited changes JGN has made to its proposal.

The submission covers five specific areas of the AER's draft decision and JGN's revised proposal. The submission does not address the important area of customer engagement and whether JGN has used the customer engagement research in the appropriate way. The EMRF provided discussion on this matter in the EMRF's original submission to the AER and we refer the AER to that commentary.

Section 2: Capital Expenditure (capex)

JGN proposed a capital expenditure (net of customer contributions) of \$1,130.4 million (\$2015) over the next period. The AER did not accept this capex amount in its draft decision, replacing it with a total expenditure allowance of \$918.6 million (\$2015), a reduction of some 19% from JGN's proposal.

In its revised proposal, JGN stated that it does not accept the AER's draft decision on capex and has submitted a revised proposal that includes a capex forecast of \$1,118 million (\$2015), effectively maintaining is initial claims.

The EMRF takes a strong position on JGN's original and revised capex proposals. JGN's proposed capex is greater than JGN's current levels of capex, which was in turn significantly higher than its capex needs under the IPART determination for 2006-2010 (in constant dollars)

JGN has failed to demonstrate that current circumstances justify an increase above historical levels of capex. The JGN network is a mature network, but one that has undergone significant replacement of older assets over the last 25 years. On all measures of performance, and particularly unaccounted for gas (UAG), JGN's network's performance has been both stable and well within regulatory performance requirements

The EMRF considers that JGN should make every effort to manage capex investment with greater prudency and efficiency as appropriate for a mature business. The challenges facing gas consumers in the future, with the real prospect of rising gas commodity prices, makes this even more critical to the long-term sustainability of the JGN network.

The AER's reductions in JGN's proposed capex should not be used by JGN to threaten the safety and reliability of the network, and in so doing damage JGN's good reputation. The AER's decision is simply placing a requirement on JGN's Board and senior management to prioritize their investment decisions, and to place reliability and safety at the top of that priority. This is no different than the requirements that face the Boards and managements of all the EMRF members every day.

Section 3: Operating Expenditure (Opex)

Overall, JGN's forecast opex for the next period represents a continuation of the high levels of opex seen in the last years of the current period (in constant dollar terms).

JGN's initial proposal for the next period opex was for some $789.3 million ($2014-15) (excluding the debt raising allowance). In its draft decision, the AER did not accept JGN's proposal and set an opex allowance of $779.7 million, a difference of around 1%.

While the AER has rejected some parts of JGN"s opex proposal, overall, the AER's approved opex is close to JGN's original proposed opex.

In its revised proposal, JGN proposed an opex of $805 million ($2014-15). The revised proposal is around 3% higher than the AER's draft decision and greater than the initial proposal. This is largely because JGN has added three additional opex items in its revised proposal, claiming a "change in circumstances"; namely:

- Gas quantity input audit;
- Meter asbestos cover removal program; and
- B2B harmonization.

The AER has not made a decision on these additional factors.

The AER applied the "base-step-trend" approach set out in the AER's Forecast Expenditure Assessment Guideline to determine JGN's efficient and prudent opex. However, as JGN was not subject to an opex efficiency benefit sharing scheme, the AER did conduct a more detailed bottom up review of the efficiency of JGN's base year opex (2013-14).

The EMRF agrees with the AER's approach to conduct a more detailed review of the base year. The EMRF also accepts the AER's draft decision on the "base year" (2013-14) adjusted expenditures and supports the AER's position on forecast labour and material cost trends.

The EMRF has, however, some concerns with the additional marketing costs approved by the AER – these are costs over and above the current marketing expenditure of $40 million, and the EMRF considers that JGN needs to first establish that its existing programs are cost effective. In addition, the EMRF is concerned with a program that might encourage gas connections when it is uneconomic to do so; not all new gas connections will reduce overall network costs to each existing consumer.

However, the EMRF had some initial concerns with JGN's so called "category specific opex costs" which include forecasts of government levies, UAG, carbon costs and debt raising costs. The AER's draft decision has adequately addressed the EMRF's concerns and the EMRF supports the AER's decision on each of these category specific opex costs.

However, the EMRF believes that the AER has not adequately addressed the issue of opex productivity improvements through the regulatory period.

The EMRF reiterates its view that JGN's opex productivity forecast of just over 1% p.a. is inadequate. The reasons for this include:

- The productivity forecast does not adequately capture the improvements in opex that should arise from the AER's increased allowance for capex in the current period This increased allowance provided for additional expenditure on remediating JGN's assets and for IT development; and

- Independent benchmarking using a number of partial productivity measures indicates that JGN experienced a gradual decline in l productivity up to 2013. However, JGN and the AER have relied on historical trend analysis to derive a forecast of future productivity growth, thus locking in the limitations of the past

The EMRF notes that JGN's revised proposal requests additional expenditure allowance for three additional opex step changes (see above). The EMRF considers the removal of meter asbestos and the B2B harmonization projects are perhaps reasonable but the AER should examine whether the proposed costs represent efficient costs.

More generally, the addition of new opex items highlights even more strongly the importance of ongoing productivity improvements in the fundamental operations of the business.

Operating in a competitive environment, the EMRF members are constantly under pressure to achieve greater levels of productivity. There is no reason why such disciplines should not apply to JGN via the economic regulatory process

Section 4: Rate of Return on Capital (WACC)

The EMRF generally supports the AER's draft decision on the efficient return on capital for JGN. The AER has arrived at this decision by applying its Rate of Return Guideline.[6] The EMRF was represented through the MEU in the year- long process of developing the Guideline.

The EMRF continues to believe that the Rate of Return Guideline delivers a very conservative outcome on the WACC, given its assumptions on the market risk premium and the equity beta. Nevertheless, the Guideline and the associated Explanatory Statement provide a relatively transparent and consistent framework for assessing an efficient rate of return for an efficiently financed benchmark efficient entity of the same risk profile that is consistent with the NGO, the NGL and the NGR. [7]

In its initial proposal, JGN proposed a WACC of 8.67%, only 176 basis points below the AER's allowed WACC for the 2010-15 period, despite the very significant reduction in interest rates and improved investment environment that now prevails. JGN adopted an approach that differed from the Guideline, particularly in the assessment of the return on equity.

The AER did not accept JGN's proposed WACC. The AER's Draft Decision allowed a WACC of 6.8%.

JGN rejected the AER's draft decision. JGN applied proposed a WACC of 7.1% in its revised proposal, using basically the same approach as in its original proposal. The reductions in JGN's revised WACC are largely a reflection of the ongoing decline in the risk free interest rates and 10-year commercial bond rates.

Table 2 below summarises JGN's proposals and the AER's draft decision. The AER will update the draft decision to reflect the changes in interest rates, and EMRF expects the final decision to show a further reduction in the overall WACC and WACC parameters.

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[6] AER, *Rate of Return Guideline* December 2014 and AER, *Explanatory Statement, Rate of Return Guideline*, December 2014. The AER's Rate of Return Guideline applied to electricity and gas distribution and transmission network companies.
[7] NGR, Rule 87 (2) (3).

Table 2: Summary of the WACC components

WACC component	**JGN Proposal (June 2014) %**	**AER draft decision (Nov 2014) %**	**JGN's revised proposal (February 2015) %**
Risk Free Rate	3.18	2.38	2.69
Return on Equity	10.71	8.1	9.87
Return on Debt (updated annually)	7.3	5.93	5.33
Overall nominal vanilla WACC	**8.67**	**6.89**	**7.15**
Gamma (Imputation Credits)	*0.25*	*0.4*	*0.25*

In assessing whether the AER's approach or JGN's approach best achieved the allowed rate of return objective in the NGR, the EMRF believed it was more useful to focus on the equity risk premium (ERP) and the debt risk premium (DRP); the premium of equity and debt respectively over and above the risk free rate. Focusing on the premium allowed consideration of the reasonableness of the proposals independently of the risk free rate changes.

The EMRF considered that the JGN's original and revised ERP were not credible. For example, in the revised proposal, the ERP is 7.18% (9.87% less 2.69% for the risk free rate), a level well above historical levels including during the global financial crisis (GFC).

The ERMF also highlighted that JGN's revised proposal implied a premium of equity over debt of some 4.54%, which again exceeds historical trends and would appear unreasonable notwithstanding differences in tax treatment of debt and equity.

Overall, the EMRF considers that JGN's multi-model approach to assessing the return on equity is at the core of the inflated ERP. The approach is complex and requires multiple assumptions and arbitrary weightings of different sources of information, leaving it open to systematic biases and compounding of errors. It is therefore not a credible basis for assessing the return on equity in a regulatory setting.

The EMRF therefore urges the AER to continue to apply its Rate of Return Guideline. A review of the limited market data suggests that the outcome of applying the Guideline will not only align with the financing costs of an efficiently financed benchmark entity, but also enable JGN to recover their actual costs of capital.

Section 5: Demand Forecast

The forecasts of JGN's customer numbers and gas usage are important inputs into JGN's capex and opex requirements and into the forecast price path under the maximum average revenue/price (MAR) form of control.

JGN is forecasting a net growth in customer numbers of some 30,000 a year, partly in response to its expanded marketing program. While this is consistent with historical trends, it seems rather inconsistent with JGN's assessment of average consumption per customer.

JGN is proposing significant declines in average consumption per customer for each class of customers in the order of 2% to 3% p.a, with the greatest reductions in the small business area. In total, JGN forecasts a reduction in volumes of more than 12% across the regulatory period.

An important driver of this reduction in average consumption is the expected increase in gas costs and supply uncertainty as the east coast gas market adjusts to the rapid growth in LGN exports from Queensland. JGN has applied both an own price and a cross price elasticity coefficient to average usage and this seems to be the key driver of lower average consumption.

However, as noted above, JGN does not consider this will be a barrier to continued growth in customer numbers at historical levels.

The AER has accepted JGN's forecast of annual quantities and peak demand for Tariff D customers. The AER has also accepted JGN's customer growth forecast but not its mix of customer types (multi-dwelling versus new estates) or JGN's proposed disconnection rate.

More significantly, the AER has not accepted JGN's forecast of average consumption per customer and has applied a lower rate of decline in average consumption to its own forecast of demand. Therefore, overall volumes are some 11,000TJ greater than JGN's forecast.

JGN has rejected the AER's draft decision and the underlying modeling used by the AER to derive the forecast (provided by ACIL Allen). JGN claims that if the AER's final decision is the same as the draft, then JGN has some $90 million at risk because the MAR form of control will not enable it to recover its allowed revenue given the higher forecast.

The EMRF noted that networks receive a benefit through higher than allowed revenues under the MAR form of control, if the forecasts include higher customer numbers and lower volumes than actually occurs (because the average price allowed will be higher).

This appears to be a major risk in JGN's forecast. While JGN considers that they risk losing $90 million as a result of the AER's forecast, the EMRF highlights that consumers sit on the other side of this risk. That is, if JGN's forecast is accepted, consumers risk $90 million of excess payments to JGN. The EMRF has noted that over the years, even when volume forecasts are subsequently seen as higher than actuals, the impact on the networks has been considerably less than would have expected;

The EMRF is also requesting the AER further investigate what appears to be an anomaly in JGN's forecasting. As noted JGN's forecast outcome for average consumption per customer is influenced by the application of its elasticity coefficients (own and cross price), given the assumption of increased gas costs.

However, JGN's tariff plan proposes significant reductions in tariffs for Tariff V customers in particular, such that the overall **retail gas price** will not change significantly despite forecasts of increased wholesale gas costs. If that is the case, then it is difficult to find a reason why average consumption should decline, or at least decline more rapidly than the general trend driven by more efficient appliances and some growth solar hot water.

Overall, and reflecting the importance of the forecast, the EMRF urges the AER to consider other independent forecasts of gas demand in NSW. The EMRF considers that the most recent forecasts of NSW gas demand by the Australian Energy Market Operator (AEMO) provide a useful reference point, albeit it is very much a "top-down" view.

The AEMO forecast appears to be closer to the AER's forecast in terms of overall rate of growth in demand for Tariff V and Tariff D customers. Given this, and the implications for consumers' network prices of lower forecasts of demand, the EMRF encourages the AER to further investigate the demand forecasts.

Section 6: Tariff structures

JGN has adopted some important reforms to its network tariffs such as simplifying tariff structures and adopting more consistent approach to tariffs. The EMRF is also very supportive of JGN's proposal to prepare a Tariff Strategy Statement (TSS) and to publish its annual network tariff updates earlier each year. This provides consumers with more ability to predict future costs.

The AER has accepted almost all the components of JGN's proposed tariff classifications and tariff structures. This includes a significant reduction in the fixed costs for Tariff V customers and a downward sloping stepped variable tariff component.

The EMRF, however, considers there is a risk in this approach. In particular, when average usage is declining at the rate JGN forecasts, there must be a concern that JGN may not recover its fixed costs from the relevant customer segment. In that case, some costs will have to be recovered from other segments, leading to an emerging cross-subsidy that will be difficult to rectify in the future. The EMRF considers that the AER has not sufficiently reviewed this issue

EMRF is also disappointed with the AER's response to the EMRF's concerns with JGN's proposal to increase Tariff D prices at around CPI (or 13% nominal over the next period), while at the same time, decreasing Tariff V customer prices quite substantially.

The reasons for this approach provided by JGN, and apparently accepted without critical appraisal by the AER, are vague and unsubstantiated.

It is accepted by JGN that Tariff D customers have a long run marginal cost of zero, place no additional costs on the system, and have provide a significant contribution to the extension of the gas network to their plant (and to the local area in general, particularly outside the Metropolitan areas).

However, JGN is now stating that it wants to restore the revenue from Tariff D customers to the same percentage of total revenue as it was before 2010. The EMRF responds by noting that in the interim, there has been an increase in Tariff V customers of around 30,000 (net) per year, while there has been a decline in Tariff D customers and a decline in the average usage of the remaining customers. It is hardly surprising that the percentage of total revenue would decline.

JGN is also ignoring the fact that large consumers have very little flexibility in the short-medium term to change their fuel and are more exposed to the wholesale market price increases. It does not make strategic or economic sense to not provide some tariff relief to these customers. The AER's draft decision provides for further aggregate cuts in total revenue and the EMRF urges JGN to discuss with Tariff D consumers how this can be used to provide relief to large users, particularly given that they impose much smaller costs on the network.

The EMRF is intrigued that JGN has asserted that it has consulted extensively with its customers about its proposals yet EMRF members have not advised they have not had the opportunity to discuss the new tariff approach. As it is easier for JGN to contact and discuss such issues with their larger customers, this raises a concern about the extent of the JGN consumer engagement process.

The EMRF also observes that larger users (such as tariff D customers) are also the first consumers constrained off by JGN when there is a gas shortage. With this in mind, it would be expected that tariff D customers should receive some benefit for their greater risk of their gas supplies being constrained rather than being disadvantaged by this new approach to cost allocation.

1 Introduction

1.1 The Energy Markets Reform Forum (EMRF)

The Energy Markets Reform Forum (EMRF) is a forum representing large energy users in New South Wales (NSW). The EMRF is an affiliate of the Major Energy Users Inc (MEU) which compromises some 30 major energy using companies in NSW, Victoria, South Australia, Western Australia, Northern Territory, Tasmania and Queensland. EMRF member companies – from the steel, aluminum, paper and pulp and the mining explosives industries – are major manufacturers in the State and are significant employers, especially in many regional centres.

The EMRF welcomes the opportunity to provide comments on the Australian Energy Regulator's (AER) draft decision[8] on the gas distribution network access arrangement proposed by Jemena Gas Networks (NSW) Ltd (JGN) for the regulatory period 2015-16 to 2019-20 (2015-20). In this submission, the EMRF also responds to JGN's revised regulatory proposal as the revised proposal disputes the AER's Draft Decision and submits a new proposal that is very similar to its original proposal. [9]

The EMRF provided a detailed submission in response to JGN's original regulatory proposal.[10] As JGN's revised proposal is generally similar to this original proposal, the EMRF regards both its first submission and this current submission as both relevant to the AER's Final Decision.

1.2 The JGN Network

JGN is the main gas distribution company in NSW and has over 1.1 million gas customers on its network. This is the JGN's second gas access arrangement to be reviewed by the AER. Prior to this, JGN was subject to regulation by the Independent Pricing and Regulatory Tribunal of NSW (IPART). The EMRF points out that it has been involved with every one of the regulatory reviews of the JGN network since the first one in 1997 under the draft gas access code.

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[8] AER, *Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015-20*, November 2014. [AER, *Draft decision, JGN 2015-20 Access Arrangement,* November 2014]

[9] Jemena Gas Networks (NSW) Ltd, *2015-20 Access Arrangement, Response to the AER's draft decision & revised proposal*, *Public*, 27 February 2015. [JGN, *Revised 2015-20 Access Arrangement,* February, 2015].

[10] EMRF, *NSW Gas Distribution Revenue Reset, A response by the Energy Markets Reform Forum*, August 2014. [EMRF, *Response to JGN 2015-20 Access Arrangement proposal*, August 2014]

JGN's gas network has some unique physical characteristics. It is the largest gas network with the greatest overall capacity. However, it is also a relatively fragmented network with areas of good pipeline coverage and areas of relatively poor coverage. It is also characterized by relatively low average consumption per customer for the mass market ("Tariff V") customers compared to, for instance, Victoria. Moreover, as in the electricity industry, the gas market has seen a slow decline in average usage per customer, although gas consumer numbers have continued to increase.

The gas usage by EMRF members represents a significant proportion of the total gas used in NSW. In Sydney and in some regional towns (particularly Newcastle and Wollongong, there would not be a gas network if it were not to meet the needs of EMRF members and other large users. The large gas users, therefore, underpin the sustainability of gas supply in many areas as well as the ongoing sustainability of small businesses and employment in these areas and employment.

1.3 The implications for the AER's final determination

The recent well-documented changes in the east coast gas market have resulted in considerable disruption to the NSW gas supply arrangements in NSW.

The uncertainty that this has created over both the price and reliability of gas supply in NSW has, therefore, led to the EMRF's heightened concern with the AER's final decision on JGN's access arrangement. The ongoing viability of the EMRF's members will be influenced by the AER's final decision. In its original submission the EMRF highlighted:[11]

- the considerable investment by EMRF members in gas infrastructure and equipment;
- the importance of a reliable supply of gas as there is no short term substitute;
- the impact of their businesses of cost increases in both electricity and, more recently in gas and the potential threat of further price increases in gas before 2020;
- the potential shortage of gas in NSW if the current political impasse is not satisfactorily resolved.

[11] Ibid, pp 13-14

Six months later these concerns are still a priority for EMRF members. Although international gas and oil prices have softened, at this stage, the international price reductions have not flowed through to competitive market offers to the members, with gas price offerings exceeding the international gas net back prices.

While the gas distribution business is only part of the problem, it is important that the AER has a focus on ensuring only prudent and efficient expenditures and financing costs are allowed in its access determination. In particular, in a period of declining average demand for gas (and for electricity) due to price response and greater efficiency in energy use, it is essential that a conservative approach is adopted in assessing expenditure requirements. Like any business in a mature market, where new technology options such as solar hot water are providing options for consumers, strict cost control is central to ensuring long-term sustainability and the avoidance of investments that might well be stranded in the future. While under a competitive regime, stranded investments are a problem for the investors, under a regulatory environment (such as applies to JGN assets) the risk of stranded investments lies with consumers.

The AER's draft determination goes someway towards this outcome and restores expenditures to historical levels in real dollar terms. Therefore, the EMRF concludes that JGN's response to the draft determination is incorrect in suggesting that the AER's reasonable constraints on expenditure are threatening the reliability and safety of a long established network business.

JGN will need to prioritize its expenditures are required and these priorities must place an emphasis on reliability and safety. However, this is no different than the processes EMRF members (operating in a competitive international market) face every day in the face of scarce capital.

The EMRF notes that the AER's expenditure constraints are merely restoring expenditure to historical levels (in real dollar terms). Therefore, the EMRF also considers that that the AER should 'hold the line' in its final decision.

In this submission, the EMRF also highlights a number of areas where the AER's draft decision might be improved in the long-term interests of gas consumers.

2 Forecast Capital Expenditure (Capex)

2.1 Summary of EMRF's view on JGN's capex proposal

The EMRF takes a strong position on JGN's original and revised capex proposals. JGN's proposed capex is significantly greater than JGN's current levels of capex, without commensurate increase in the underlying factors that drive capex.

The EMRF considers that JGN should make every effort to manage capex investment with greater prudence and efficiency, given the fact that the gas network market in NSW is relatively mature and faces a number of challenges over the next five years.

What consumers cannot accept is JGN's higher capex proposals which increase the risk for future gas consumers through increasing the asset base without commensurate increase in utilisation of that asset base.

In the absence of JGN constraining its proposed capex to current investment levels, it is the role of the AER to act in the long-term interest of all stakeholders and ensure only prudent and efficient capex is included.

2.1.1 The gas networks must face the same market discipline as their customers

Any industry, or firm, in transition and facing the challenges of technological change, limited growth in demand for their product and price pressures must make choices in how it spends its capital. It is the responsibility of the Board and senior management of the firm to set the priorities taking into account all these factors.

The domestic gas distribution market is a mature market but one still returning a steady cash flow that is attractive to investors. Like any mature market or product the strategic emphasis must be on strict control of expenditure while continuing to deliver quality services to its customers.

JGN's proposal to significantly increase capital investment, and thereby build in future price rises,[12] rather than consolidate its current operations and focus on efficient delivery of quality service, is not a strategy that would succeed in the competitive market.

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[12] This is because the proposed network price reductions by JGN, simply reflect the lower cost of capital, not expenditure constraint. If/when interest rates move up, consumers will still be left with the "bill" for the higher RAB value.

The EMRF also highlights that this disciplined approach to capex is required by the NGR, which sets out the "new capital expenditure requirements" as follows:[13]

> *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the **lowest sustainable cost of providing services**.* [EMRF emphasis]

In the EMRF's view, the AER's draft decision, which constrains capex to the existing levels of expenditure, is the more correct response to ensure ongoing sustainability of the gas network. The draft decision is therefore a more preferable decision in the long-term interests of consumers.

2.1.2 This does not mean reliability and safety can be jeopardized; these remain priorities for the business

Given the recent debates arising out of the AER's draft decisions in NSW electricity and gas networks (including JGN), it is important for the EMRF to state clearly that its position on capex does not mean it is indifferent to reliability and safety or to JGN's regulatory compliance in general. These are matters that are essential to the sustainability of the gas network business. It is up to the Board and senior management of JGN to ensure they remain a priority, even as it limits investment in other areas.

For this reason, the EMRF rejects the assertion by JGN (and other networks), that expenditure allowances – particularly when these are still consistent with historical expenditures (CPI adjusted) - will mean that JGN cannot meet its regulatory requirements for reliability, health and safety.

EMRF members face these choices every day under competitive market pressures, but they do not threaten the community's safety in doing so. They simply make that the priority and adjust expenditures in other areas of the business.

2.1.3 The costs of JGN's capex proposals are not equally shared

The EMRF considers that the impact of JGN's proposed additional expenditure (above historical capex levels) is unfairly shared.

JGN has proposed decrease in gas network tariffs for smaller customers (V tariff customers). However, much of this decrease is enabled by the lower cost of capital that has no direct relationship to the efficiency and prudency of JGN's expenditure proposals. Had JGN proposed expenditures similar to its previous expenditures, the savings would have been greater.

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[13] NGR, Rule 79 (1) (a).

More particularly, the EMRF has highlighted in is original submission that JGN is proposing price increases to the larger D tariff customers. For example, it appears that JGN has now advised the AER that large users will face a price increase of around 13% for the 2015-20 access arrangement period [14] (including, it appears, savings from the carbon tax removal[15]). Should demand fall further and/or interest rates rise this increase will be greater.

The EMRF notes that JGN's own analysis has indicated that the long run marginal cost (LRMC) for large users is zero,[16] D tariff customers have more favorable load factors and demand is flat.[17] As JGN also notes:[18]

> *At an aggregate network level, JGN's capacity requirements are not driven so much by load peaks as by volume market expansion (i.e. new customers).*

As D tariff customers are not increasing in number (or average volumes), they are not a source of capacity expansion costs. Moreover, D tariff customers have generally funded much of the infrastructure related to their gas supply connections and reinforcements. As JGN also states:[19]

> *Where the expected costs [of a D tariff customer] exceed the [expected] revenues, JNG charges a capital contribution to the connecting customer. The fact that these users pay a contribution to any capacity development costs not covered by JGN's existing charges means JGN's net LRMC can be expected to trends towards its prices to these customers.*

In summary therefore, large users are not benefiting from the savings in the cost of capital that is supporting lower prices for V tariff customers. However, D tariff customers are carrying the additional costs, and risks, of the expenditure expansion plans of JGN for the V tariff customers.

The question of JGN's proposed approach to network tariffs will be further discussed in Section 6 of this submission.

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[14] See AER, *Draft Decision Jemena Gas Networks Access Arrangement*, Attachment 10: Tariff setting, November, 2014. JGN appears to have advised the AER of this plan in response to an information request, after JGN published its initial proposal (see footnote 30 of the AER Attachment 10, p 10-13).
[15] Ibid, p 10-13.
[16] See JGN, *2015 Access Arrangement Information, revised proposal*, February 2015, p 29 ((@77).
[17] Ibid.
[18] Ibid, p 30 (@ 80).
[19] Ibid (@83).

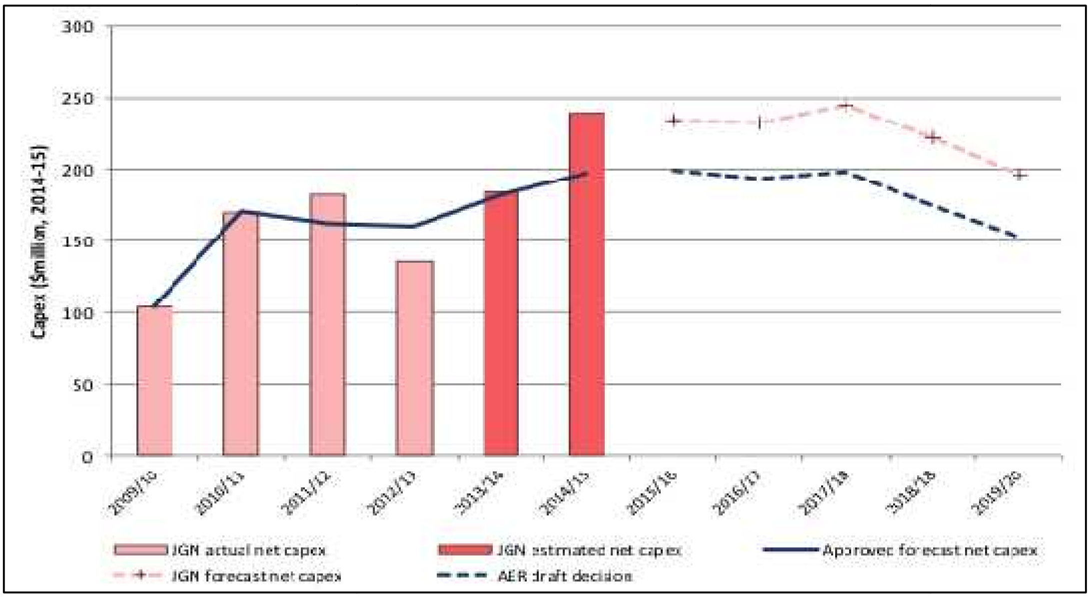
2.2 Overview of JGN's Capex Proposal and AER's draft decision

JGN proposed a capital expenditure (net of customer contributions) of $1,130.4 million ($2015) over the next period. The AER did not accept this capex amount in its draft decision, replacing it with a total expenditure allowance of $918.6 million ($2015), a reduction of some 19% from JGN's proposal.

In its revised proposal, JGN stated that it does not accept the AER's draft decision on capex and has submitted a revised proposal that includes a capex forecast of $1,118 million ($2015). In coming to this revised forecast, JGN has reduced its initial claim for overhead costs but increased its proposed expenditure on market expansion, meter renewal and upgrade and IT costs.

Figure 2 Illustrates JGN's initial proposal and the AER's draft decision. Given JGN has only marginally reduced its total capex, the current differential between the AER's decision and JGN' proposal remains largely as illustrated in Figure 2.

Figure 2: AER draft decision compared to JGN"s initial proposal ($ million, $2015)



Source: AER, *Draft Decision: Jemena Gas Networks (distribution) 2015-20*. Fact Sheet, November 2014, p 2.

Given that JGN has not significantly changed its capex in its revised proposal (or, as noted above, has increased its capex in some areas), the EMRF considers that the issues raised in its initial submission to the AER remain relevant considerations as part of this current submission.

In assessing both the AER's draft decision and the revised proposal by JGN, the EMRF will be considering whether the relevant capex allowance/proposal meets the requirements for "conforming capital expenditure" under the NGR. NGR Rule 79 (1) states:

> *(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:*
>
> *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services.*
> (b) *the capital expenditure must be justifiable le on a ground stated in subrule (2)*
>
> (2) *Capital expenditure is justifiable if:*
>
> *(a) the overall value of expenditure is positive, or*
> *(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or*
> *……*
>
> *(3) In deciding whether the overall value of capital expenditure is positive, consideration is to be given only to economic value directly accruing to the service provider, gas providers, users and end users.*

The EMRF concludes that JGN's initial capex proposal and its revised proposal do not meet the requirements of the NGR for conforming capital expenditure. The reasons for this will be explained in the following sections.

2.3 Summary of EMRF's response to JGN's initial regulatory proposal

The EMRF had a number of concerns with JGN's initial regulatory proposal. In large part these concerns arose from the fact that JGN was proposing a significant increase of around 19% in capex relative to both its allowed and actual capex in the 2010-2015 period access arrangement period..

Considered at a high level, this increase in capex appeared inconsistent to the EMRF with a network where overall demand growth was limited and average usage per customer was in significant decline. Adding significant increases to the regulatory asset base and associated capital costs (return on and return of capital) appeared to be inconsistent with prudent management of the network and with ensuring the sustainability of network prices over the longer term.

The ERMF considered this was of particular concern given the expectation that gas prices will rise irrespective of any changes in the network prices. The competitive position of gas for residential, commercial and industrial usage in NSW will be challenged by the expected rapid rise in gas prices from 2015. Other factors include the continued roll out of solar PV and water heating and the development of more efficient electricity appliances (such as reverse cycle heating).

Therefore, the ERMF urged the AER to undertake a comprehensive review of the proposed capital expenditure.

In recommending this, the ERMF was particularly concerned for the AER to closely examine whether the following items represented prudent and efficient capex as required by the NGR:

- The expected surge in capex in 2014-15 and whether this increase above the regulatory allowance met the requirements of conforming capex under the NGR;[20]

- JGN's proposal for large increases in capex for "market expansion/connection", noting the challenges facing the NSW gas market (see above);

- The associated forecast of 150,000 new connections (a 12% increase on the current rate of additions) and 2,000 km of new gas main (8% increase);

- JGN's focus on expansion of gas into new areas, requiring extension of the gas mains, particularly at a time of declining average consumption by households and small businesses – the EMRF stated a need to see a cost-benefit analysis of pursuing connections in these areas;

- The relatively high replacement/renewal expenditure for meters, facilities and mains and services, particularly given the very long life of most gas equipment and the near completion of the program to replace cast-iron gas pipes throughout the gas supply region;

- The program to replace 150,000 faulty hot water meters; the ERMF could see no valid reason for gas consumers in general to fund this replacement program given it appeared to reflect issues that are not

[20] Under the NGR, the AER is required to assess if this excess capital meets the test of "conforming capital expenditure"; if it does then it will form part of the opening regulated asset base. See NGR, Rules 78 - 79

related to their service requirements and in any case, should sit between JGN and its hot water meter supplier;

- JGN has included costs of connecting its network to new sources of CSG gas supply in NSW without demonstrating when/if this will ever occur(especially in light of the government determination to suspend CSG exploration and development); and

- JGN has escalated its material and labour (internal and external) costs above CPI, when there is insufficient evidence to support this proposal.

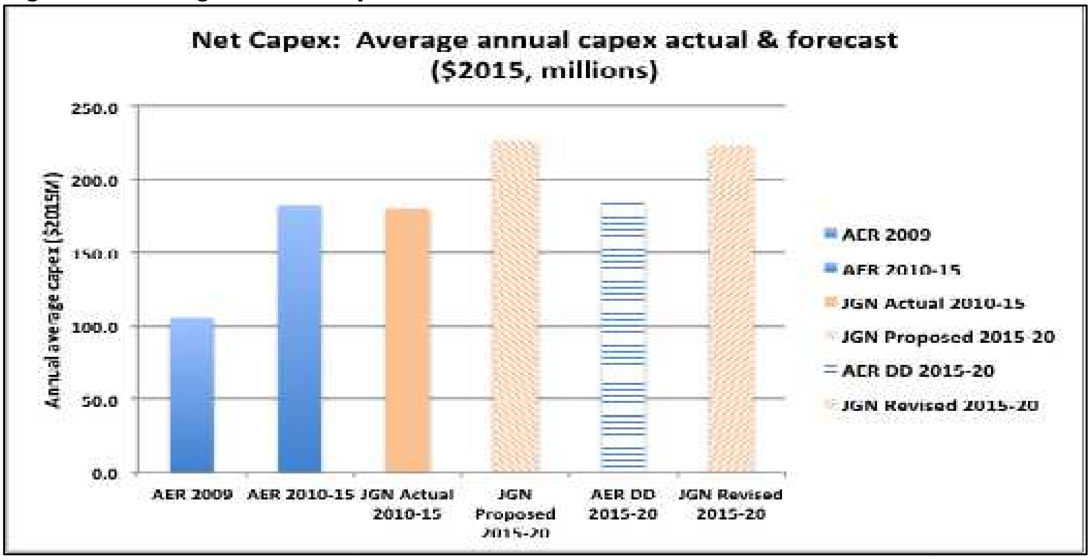
2.4 The AER's Draft Decision on JGN's Capex

2.4.1 Overview of AER's Draft Decision on JGN's Capex

Figure 3 below summarises the average annual capex for 2010-2015 (both allowed and actual). It also includes JGN's initial proposal, the AER's draft determination and JGN's revised proposal.

Figure 3 also demonstrates that the AER allowed a significant increase in the 2010-15 period compared to the decision by the NSW Independent Pricing and Regulatory Tribunal (IPART) for the preceding regulatory period (2005-2010).[21]

Figure 3: Average annual capex current and forecast



Source: AER and JGN AA reports, EMRF analysis.

[21] IPART was the economic regulator prior to the transfer of network regulation to the AER. The estimated expenditure for the last year of that regulatory period (2009-10) was $105.3 million $2015).

In its initial proposal for the next period (2015-20), JGN proposed a significant increase over the current allowance, and over its actual expenditure of some 19%. JGN's proposal is equivalent to an annual expenditure of some $223.6M ($2015), which is more than double its allowances provided under IPART in real dollar terms.[22]

The AER has rejected this proposal and replaced it with a capex allowance of $183.7 million (average per year), an allowance that is similar to its previous allowance for the current period (in real dollar terms). However, in its revised proposal, JGN is proposing capex similar to its original proposal of around $220 million per year ($2015)

2.4.2 The AER's Assessment of JGN actual capex for 2009-14

In the first part of the AER's assessment, it is required to assess whether JGN's capex for 2009-14 is conforming capex as defined in the NGR (r. 79(1) – see above).

The AER approved JGN's capex of $775.9 million ($2015) for 2009-14 as conforming capex that complies with NGR r. 79(1) (see above).[23] However, the AER also highlighted that: [24]

- JGN significantly underspent its allowance in the capex categories of connections/market expansion; meter renewal and upgrade and facilities renewal and upgrade;

- JGN significantly overspent in the categories of overheads (largely due to a cost allocated to Jemena from the Jemena Group corporate for IT), and in IT.

The AER was reasonably satisfied with JGN's explanation for these variations. The AER, however, made no comment on the fact that JGN's actual expenditure in the last year (2014-15), which is not included this analysis, was significantly greater than previous years and above the AER's allowance (see Figure 3 above).[25]

2.4.3 The AER's Assessment of JGN"s forecast capex

As noted above, in its draft decision, the AER has amended JGN's forecast capex, reducing it by some 19%. The key elements of the AER's decision include reductions in those capex areas where JGN had proposed

[22] See above note.
[23] Ibid, p 6-18.
[24] Ibid.
[25] The AER will assess the 2014-15 capex as part of its assessment in the next regulatory period (2020 – 2025). However, in the interim, JGN will get the benefit of its inclusion in the RAB.

significant increases. For example, the AER made the following constituent decisions:

- Reduction of 18% in JGN's proposed connections/market expansion capex. The AER did not accept either the volume or average unit costs for these connections and extensions; [26]

- Reduction of some 8% in augmentation capex. The AER accepted only some 82 of the 93 of JGN's proposed augmentation projects ,[27] in most instance because it considered that the projects were not needed during the coming period; [28]

- Reduction of some 5% of JGN's proposed mains and services capex, largely on the basis of the costs of some projects. The AER also highlighted that the allowed expenditure is some 147% above that provided for the current period;[29]

- The AER has accepted JGN's forecasts of costs for remediating the network from mine subsidence but has proposed using the historical proportion of costs covered by customer contributions. JGN had suggested these contributions would decrease;[30]

- Reduction of some 17% in JGN's facilities & renewal upgrade capex. The AER rejected 8 of the 90 projects proposed by JGN including the upgrades associated with the potential connection of NSW CSG supply to the NSW networks. The AER noted that JGN's forecast represented an increase of 71% over its expenditure in the current period;[31]

- Reduction in JGN's proposed SCADA. Network Control System capex. The AER notes that JGN's forecast capex is nearly three times historical costs. The AER has substituted JGN's forecast with a capex allowance that is similar to the 2010-15 capex;[32]

- Reduction of JGN's proposed meter renewal and upgrade capex by some 17%. The AER notes that JGN's forecast is some 76% higher than the current period capex.[33] The AER did not accept JGN's proposed replacement rates based on the assessment of historical trends. The AER is also seeking further unit cost information;[34]

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[26] Ibid, p 6-21.
[27] Ibid, pp 6-26 to 6-27.
[28] Ibid, p 6-29.
[29] Ibid, p 6-31.
[30] Ibid, p 6-32.
[31] Ibid, pp 6-33 to 6-35.
[32] Ibid, pp 6-35 to 6-36
[33] Ibid, p 6-37.
[34] ibid.

- The AER has accepted JGN's proposed IT capex on the basis that it is necessary to meet its obligations and is consistent with previous IT expenditure; [35]

- The AER has largely accepted JGN's proposed capex for other non-distribution capex that includes property, vehicles, tools and equipment. JGN's forecast is significantly less than its 2010-15 capex;[36]

- Reduction of some 25% in JGN's proposed capex for "overheads". The AER notes that JGN's proposal is some 23% increase over the current period in real dollar terms;[37]

- The AER has rejected JGN's proposal to include a margin to the capex performed by a related party, Zinfra (market expansion/connections capex);[38] and

- The AER has also revised down the material cost escalation (in real dollars) to zero. The AER does not accept that JGN has made a reasonable case for future real increases in material prices.[39]

2.5 JGN's Response to the AER's draft decision

JGN has not accepted the AER's draft decision on the capex allowance. JGN's revised proposal is generally similar to its initial proposal (in terms of the quantum of the dollars), although expenditure on overheads has been somewhat decreased.

The reasons for JGN's view that the AER has erred are set out in JGN's revised proposal, dated 27 February 2015.[40]

JGN has framed its overall response to the AER in terms of the expectations of its customers, as follows:[41]

> *Our customers told us they preferred to maintain our existing service levels and to provide a universal level of service to all our customers by 2020.*

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[35] Ibid, pp 6-41 to 6-6-43
[36] Ibid, pp 6-43 to 644.
[37] Ibid, p 6-44.
[38] Ibid, p 6.47.
[39] ibid, pp 6-58 to 6-59. (Attachment A)
[40] Jemena, *Jemena Gas Networks (NSW) Ltd 2015-20 Access Arrangement, Response to the AER's draft decision & revised proposal*, 27 February 2015 (Public Version). [JGN, Revised Proposal, February 2015].
[41] Ibid, p 44.

> …
> *We are very concerned that the AER has not tested the short and long-term consequences of this decision with customers, but it is somehow confident to assert that this outcome is what customers would want.*

JGN also sets out its view that expenditure to: “economically extend and expand the network reduces tariffs for all customers and helps ensure the relative competitiveness of gas”.[42] Similarly, JGN states that prudent and efficient refurbishment and replacement expenditure delivers on the customers’ stated preferences that safety remains the “number one priority”.[43]

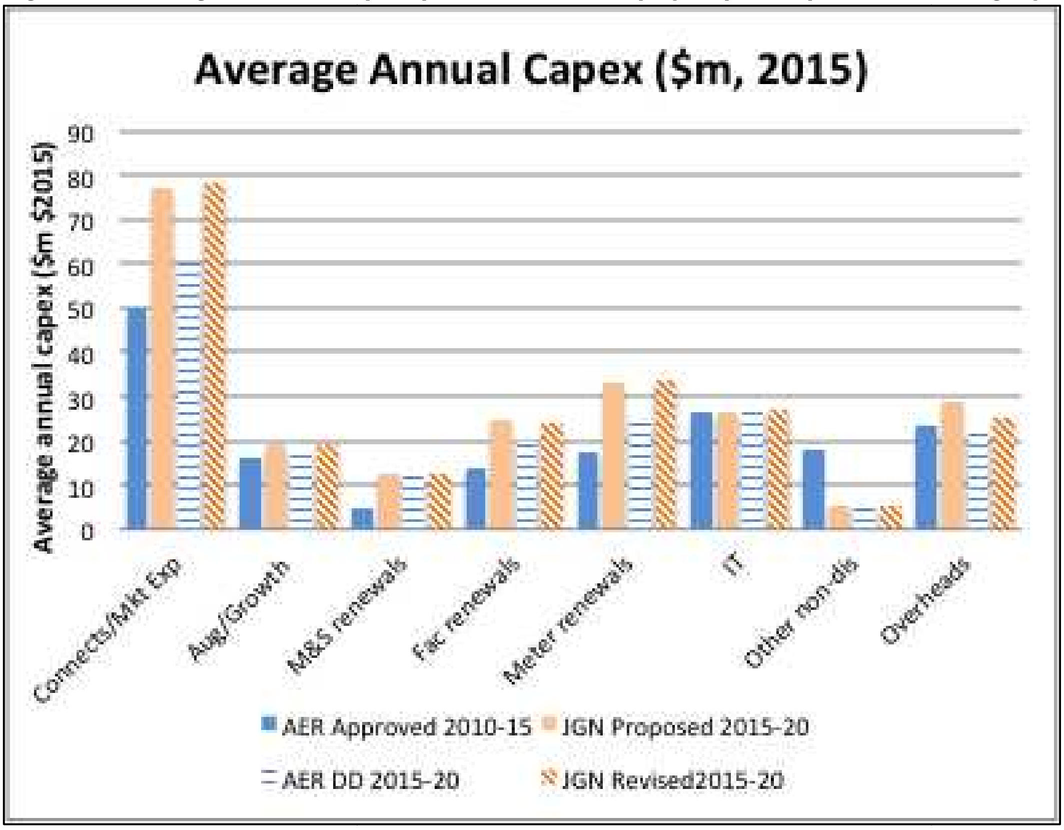
JGN’s statements suggest that if the AER maintains its draft capex decision, then the service levels and safety currently provided by JGN would be compromised. JGN asserts that its customer engagement processes support its conclusion. The EMRF questions this. Whilst the EMRF is aware that consumers do not want a lesser service, they also have stated explicitly they do not want prices to increase, and expected that with lower costs of capital, there would be price reductions.

What JGN has failed to do it demonstrate that the lower capex will result in a less safe or reliable network - this has just been asserted. In fact, the same levels of safety and reliability have been achieved in the past with similar levels of capex to that allowed in the AER draft decision is entirely overlooked by JGN.

Figure 4 below illustrates the average annual capex allowed under the AER’s draft decision and JGN’s original and revised proposals. The AER’s average allowance for AA1 (2010-2015) is included as illustration of the extent to which JGN has increased its expenditure in a number of capex categories compared to AA1 and the AER’s draft decision.

[42] Ibid.
[43] ibid.

Figure 4: Average Annual Capex ($ millions, $2015) by capex expenditure category



Source: AER Draft Decision, JGN original and revised proposal, EMRF analysis

Listed below are a number of other more specific features of JGN's revised proposal where it:

- Addressed some of the data issues that the AER raised in its draft decision;
- Clarified the purpose of a number of its projects;
- Disputed the AER's use of historical cost trends, largely on the basis of JGN restructuring its service provider arrangements with new contracts and additional costs;
- Repeated its claim for recovery of related party margins for work performance by Zinfra;
- Restated most of the projects that the AER had judged as not efficient and/or not prudent in the current circumstances; including the proposed expansions for CSG; and
- Increased a number of costs from its original proposal, including those that had been cut back by the AER. In particular, JGN

increased its proposed connection/market expansion costs and meter renewals.

Overall, the EMRF is not convinced that JGN has provided sufficient evidence to support its assertions that the AER draft decision will not deliver what is required under the NGR nor will meet the expectations of consumers.

2.6 EMRF Response to the AER Draft Decision and JGN's Revised Proposal

As noted previously, as JGN has not amended its capex proposal to any significant degree; the EMRF therefore considers much of its original commentary is still relevant to this submission.

In this response, therefore, EMRF's submission will focus largely on the question of whether the overall capex allowance proposed by JGN seems prudent and efficient. And if not, is the AER's decision a preferable decision?

However, we would encourage the AER to continue to critically review the individual projects and replacement expenditures that have been set out by JGN in its proposal and repeated in its revised proposal.

2.6.1 Review of the AER's Draft Decision

The EMRF considers that the AER has addressed the majority of the issues raised by the EMRF. For example, the AER has significantly reduced capex related to connections/market expansion, facilities and meter renewals. The AER has also recognised the EMRF's concerns with JGN's proposed increases in labour and material costs.

In doing this, the EMRF considers that the AER has also made a preferable decision on capex allowance and one that responds to the current challenges of the NSW gas market – although there are a number of areas that are still questionable in the view of the EMRF as discussed below.

In particular, the EMRF agrees with the AER's draft decision to reduce the total capex allowed for the next period to the levels of the allowed and actual expenditure for AA1 (which are very similar).

The EMRF cannot see any substantial "new events" that would warrant JGN undertaking additional expenditure compared to previous years. For instance, JGN has funded ongoing connection growth in the past – and in fact recent years have seen above average growth in connections– within the current period capex allowance.

Similarly, JGN has, in the past, had to invest in a program of replacement of old cast iron pipes. This program is almost complete, with cast iron pipes representing less than 10% of JGN's gas mains assets, and the same level of replacement expenditure should no longer required.

The EMRF also supports the AER rejecting JGN's proposal for a higher rate of gas meter replacement. JGN has always had to meet standards with respect to gas meter accuracy and these standards have not changed. Moreover, the observed trends in unaccounted for gas (UAG) do not support any urgent problem with meters, services or mains (see Figure 5 below).

However, the EMRF does not agree with the AER's acceptance of the hot water meter replacement program totaling some 150,000 hot water meters. In fact, the AER appears to ignore the issues raised by the EMRF. Section 2.6.3 includes an additional discussion on the issue of hot water meters

2.6.2 JGN's current performance and what it suggests about capex requirements

In addition to the comments in section 2.6.1, JGN's annual performance report to the NSW Government suggest that JGN's reliability and safety performance has remained very strong, and it has been able to maintain that (or even improve) on the current period capex allowance. The tables in Figures 5 and 6 below are taken from this 2013-14 annual performance report.[44]

[44] NSW Trade & Investment Resources & Energy, *New South Wales 2013-14 Gas Networks Performance Report, 2013-14*, 2014. The report also includes a number of small gas reticulation areas in NSW operated by ActewAGL Distribution (operating in Queanbeyan/Bungendore and Nowra regions); Australian Gas Networks (formerly Envestra) operating in the Albury and Wagga Wagga regions; and the APA Group, operating in the Central Ranges and Tweed Heads. However, these networks have considerably fewer customers and smaller areas than Jemena NSW. http://www.resourcesandenergy.nsw.gov.au/energy-supply-industry/pipelines-electricity-gas-networks/gas-networks/performance-reports

Figure 5: NSW gas networks: Summary statistics

Reporting Period	Network Growth in NSW in km	Gas entering the Network in PJ	Gas Delivered in PJ	Percent Unaccounted for Gas (UAFG) %
2008/09	196	111.5	109.5	1.96
2009/10	262	108.6	106.3	1.78
2010/11	342	112.9	110.2	2.45
2011/12	252	111.5	108.5	2.66
2012/13	298	114.5	112.0	2.16
2013/14	351	109.2	107.4	1.67

Source: NSW 2013-14 Gas Networks Performance Report, 2014, Table 2.1, p 10

Figure 6: NSW gas networks: annual reliability and service standards Source: NSW

Reporting Period	Unplanned Consumer hours lost per 1,000 consumers	Unplanned loss of supply incidents per 1,000 km	Number of out of spec gas or odorant levels reports	Number of Incidents/ emergencies per 1,000 consumers	% Incidents/ emergencies responded to within 60 min.
2008/09	16.10	1.76	54	2.22	97.63
2009/10	383.48 *	1.67	12	2.38	99.78
2010/11	71.67	1.79	50	2.15	99.49
2011/12	33.92	2.54	14	2.31	99.89
2012/13	18.94	1.90	14	2.22	98.70
2013/14	137.15 **	2.09	14	2.35	98.76

* A significant contamination incident at the Bowral trunk station, impacting 8,905 consumers, was the cause of the jump in hours of lost supply in 2009/10.

** Bushfire in Blue Mountain on 17-10-2013 affected 760 customers caused significant increase in hours of lost supply.

2013-14 Gas Networks Performance Report, 2014, Table 2.1, p 17

The report concludes as follows:[45]

> *The Network Operators have demonstrated a high level of performance in the areas of network integrity, reliability and safety.*

[45] Ibid, p 6.

> *The state averages for the KPIs indicate that all assets are being maintained to a very high standard.*
>
> *…*
>
> *The results remain strong and indicate that the Network Operators continue to manage their assets in a safe and reliable manner.*

The EMRF considers that these, and other, measures of performance (including measures of the high pressure mains) in the report suggest that JGN has performed very well in the past and has reached a "steady state" of performance. There is no "downward" trend in any of the measures of safety and reliability.

The EMRF also concludes that JGN has been able to sustain this high level of reliability over some six years with much lower capex than they are now proposing.

Therefore, the central question is not whether this or that project is necessary. The central question is why JGN considers it requires such a **substantial increase in capex in the next period** to maintain the same levels of network integrity, reliability and safety as it has successfully maintained before.

This question is particularly germane because JGN has placed much reliance on the views of consumers that they want the current level of service maintained. Consumers have also indicated that they do not want to pay more for better services.

However, what consumers should have been asked, is whether they want to pay significantly more in the future for the same level of service they currently enjoy – because that is what JGN is actually suggesting albeit it is disguised because of the benefit of the lower rate of return which allows network price reductions to some consumers even with additional expenditures.

The EMRF considers, therefore, that there must be a very high regulatory threshold to justify additional expenditures (in real dollar terms) over and above the level that has delivered consistently satisfactory service over the last five to six years while also growing the network at the rate of around 30,000 net customers per year over the 2010-2015 period..

JGN has not addressed this threshold issue of explaining the reasons for its **incremental capex**. Rather, JGN has focused its revised proposal on individual projects and whether each of these, taken in isolation, is prudent and efficient. Effectively, JGN is arguing that its capex needs to increase based on a bottom up approach whereas the top down assessment based on trends, clearly highlights the bottom up approach overstates the need.

The EMRF would contend that JGN must establish the reasonableness of its overall capex expenditure, even if that means individual projects must be reprioritized. JGN's customers face this task every day, in a competitive and capital constrained market and expect that the same will be applied to regulated firms like JGN.

2.6.3 Extending and upgrading the network assets

While it is not the intention of the EMRF to examine each of the projects proposed by JGN, there are a number of the proposed projects that are worthy of individual comment.

The assessment has three parts:

- Are these projects prudent and/or efficient with a reasonable likelihood of meeting the conforming capex requirements of net benefit?

- Are these projects "new", in the sense that they might/should have been carried out during the current period using the under-run in capex to implement them (i.e. are the projects incremental to the business, or deferrals from the current period)? and

- Are they projects whose costs are rightly allocated to all gas consumers?

Is expenditure prudent and efficient?

The EMRF would, for example, question whether the extension of the networks by some 400 km per year (2,000 over the next period) is a prudent target in the current circumstances of rising gas prices.

As illustrated in the Figure 5 above, the total NSW network growth (including other network providers) has not exceeded 350 km/year. JGN itself reports that it is averaging approximately 200 km of new gas mains per year.[46]

The figure proposed by JGN is even more concerning if, as JGN also suggests, around half of the proposed connections are for multi-unit dwellings. [47] Presumably most of these multi-unit dwellings would be located in areas where mains gas already exist, reducing the need for new mains. JGN also notes that while new homes

[46] See for instance, Jemena Media Release; "Jemena to upgrade gas network in North Ryde", 3 September, 2014. http://jemena.com.au/Assets/About/Media/2014/Jemena%20to%20upgrade%20gas%20network%20in%20North%20Ryde.pdf

[47] See for instance, *JGN, Revised 2015-20 Access Arrangement*, February 2015, p 26 (@172 – 181)

require 16.9 metres of main per connection, medium density requires only 0.9 (on average).[48]

EMRF also calls into question whether all the new connections are a net benefit to the system for two reasons:

- average consumption of new connections is lower than the existing average use, and moreover is declining; and
- JGN is planning to change its tariff structures and, in particular, to reduce the fixed cost component.

The reduction in the fixed cost has the advantage of reducing barriers to gas connection for the customer. However it also challenges the key requirement in the NGR, that the project be of net benefit; that the present value of the incremental revenue exceeds the present value of the incremental expenditures.

If there is not a net economic benefit, then the additional unrecovered costs will be shared across all other gas customers. The EMRF would, therefore, prefer to see a more transparent assessment of whether the pipeline extension plan will be a net benefit in practice, given the tariff proposals.

Are the projects incremental?

If JGN wishes to claim additional capex (in real dollar terms) over and above its previous allowance, it must establish that either costs have escalated substantially or that the proposals are “new”.

This latter requirement is similar to the AER’s “base, step, trend” approach to operating costs (opex). In this instance, the AER has made clear that any “step up” in expenditure must be justified as truly incremental, not just business as usual activity that would be also part of the base year.

JGN has been connecting meters, expanding the network, upgrading the network, rehabilitating mains, renewing its other assets as required in the current period. There is no real evidence provided that JGN’s proposed projects are “incremental” in this sense and therefore it is difficult to see a reason for the overall increase in expenditure. Similarly, there are no substantial increases in input costs – most are trending around the CPI, some costs are declining.

[48] ibid, Table 4.8, p 54 (@283).

Are the project costs rightly allocated to gas consumers?

Hot water meters: The EMRF has already expressed its concern with the costs of replacing faulty hot water meters, particularly given JGN's plans to replace 150,000 hot water meters that should be still within their technical operating life.

Leaving aside the issue of whether gas consumers should pay for hot water meters (and associated data loggers, communication upgrades etc); this is a clear case of systematic failure of equipment (rather than life cycle failures). If JGN believes it must replace the faulty meters, then surely this is a cost that must be argued between JGN and the relevant manufacturer or supplier.

The EMRF is also disappointed that the AER did not follow up on this issue in the draft decision to consider whether gas consumers in general should incur the cost of faulty equipment.[49]

In addition, the supply of gas-heated hot water to multi-unit dwellings is a growing market opportunity for JGN. However, this also means that the AER must take time to more carefully consider how the costs of this should be allocated across all consumers.

On the other hand, the EMRF notes, and agrees, with JGN's proposal to charge a special tariff for these cases, in an attempt to ensure better cost recovery particularly for the cost of additional meter data loggers and associated communications.

However, the EMRF is concerned that tariff D customers are seeing an increase in prices yet tariff V customers are seeing a significant decrease in prices. The import of this is that tariff D customers will effectively be paying for this increased cost yet not gaining any benefit from it.

Mines Subsidence: The EMRF is concerned that JGN's revised proposal still includes an additional amount (almost triple) for the costs of remediating its assets following mine subsidence. This has been a long-standing issue but it seems clear that this is not a cost that should be borne by gas consumers in general.

However, the EMRF acknowledges JGN's concerns with the proposed amendments to the relevant legislation: the *Mine Subsidence Compensation Act* 1961 no 22. The proposed amendment bill will have the effect of preventing JGN recovering

[49] The EMRF notes, for instance, that the AER did not allow SP Ausnet to pass-through the costs of replacing smart meters that did not meet requirements.

costs for actions taken to protect its assets when no subsidence has occurred but JGN believes it is reasonably likely to occur.[50]

Of course, this does not prevent JGN seeking recovery of costs where subsidence has already commenced.

More generally, the EMRF would expect JGN to recover costs from a third party whenever there is a specific line of accountability, rather than from consumers. Similarly, the EMRF expects JGN to carry its own costs where expenditure reflects poor project management, equipment decisions (including IT and communications) etc.

Do the projects have sufficient certainty for inclusion, ex ante, in the capex allowance?

An example of this is the proposed upgrade and reinforcement of the network at Newcastle in anticipation of additional coal-seam gas (CSG) from northern NSW. JGN proposed to recover the capex for this work in advance of the finalization of the NSW CSG policy framework and in the face of significant community resistance to the development.

The EMRF understands the need for JGN to plan ahead of the CSG project. The EMRF is also very supportive in principle with encouraging and facilitating more diverse sources of gas supply to NSW.

In addition, the EMRF has also read the letter from AGL that JGN provided in its revised proposal. The letter confirms AGL's current plans to commence flow from the CSG wells by 2016.[51]

However, the EMRF has also examined the NSW Gas Plan that was recently published by the NSW Government. [52] The Plan identifies 17 key actions under five priority "pathways" to "reset" NSW's approach to gas. They are:[53]

- Better science and information to deliver world's best practice regulation;
- Pause, rest and commence: Gas exploration on our terms;

[50] See for instance, http://www.austlii.edu.au/au/legis/nsw/bill/mscab2014371/. The amendment was designed to close the door on claims such as Jemena's successful claim for expenditures in advance of actual subsidence.
[51] Jemena, 2015-20 Revised Access Arrangement, Appendix 04.06.
[52] NSW Government, *NSW Gas Plan, Protecting what's valuable, Securing our future.* 2014. http://www.resourcesandenergy.nsw.gov.au/energy-supply-industry/legislation-and-policy/nsw-gas-plan
[53] Ibid, p 6.

- Strong and certain regulation;
- Sharing the benefits; and
- Securing NSW gas supply needs.

The EMRF notes that the Gas Plan is developed in addition to the existing changes in regulation including a freeze on new Petroleum Exploration Licences, preventing CSG activities in “sensitive areas, an aquifer policy, increased scrutiny and regulatory oversight, ban on use of BTEX chemicals, code of practice for fracking activities, greater consultation, and reforms to land access.

The EMRF must conclude that AGL’s target date of 2016 for a significant flow of CSG is optimistic, given all the new requirements listed above[54]. However, the EMRF considers additional gas supply is a critical issue for NSW consumers and the AER should provide a mechanism for allowing recovery of JGN’s efficient costs if/when there is some form of commitment by AGL to JGN on its timing of access to the network.[55]

[54] The EMRF notes that in the electricity market, contingent projects are permitted - ie that a project can proceed subject to certain milestones being met. The EMRF considers that the connection to the CSG fields might well fall into the category of a contingent project.
[55] In any case, requiring a foundation commitment from a potential user is reasonably standard in any major network development project.

3 Forecast Operating Expenditure (opex)

3.1 Summary of EMRF's response to JGN's opex proposal

Rule 91 (1) of the NGR requires that opex must be such as would be incurred by a prudent and efficient service provider in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering the pipeline services.

JGN's forecast capex for the next period represents a continuation of the levels of capex seen in the last years of AA1 (in real dollar terms). While the AER has rejected some parts of JGN"s opex proposal, overall, the AER's approved opex is close to JNG's proposed opex

The EMRF accepts the AER's draft decision on the "base year" (2013-14) (after adjustment of certain expenditures) and considers that the AER has addressed most of the EMRF's issues with the base year.

The EMRF also supports the AER's position on forecast labour and material cost trends. However, the EMRF does not accept the AER's proposed acceptance of a number of the "step changes", and has some concerns about both the approach and content of the "category specific costs".

Additionally, the EMRF considers that the AER has not adequately addressed the issue of opex productivity improvements through the regulatory period.

The EMRF reiterates its view that JGN's opex productivity forecast does not adequately capture the improvements in opex that should arise from the AER's increased allowance for capex in the current period (compared to IPART's decisions). This increased allowance provided for additional expenditure on remediating JGN's assets and for IT development both of which should generate savings in the next period, but this does not seem to have occurred.

Operating in a competitive environment, the EMRF members are constantly under pressure to achieve greater levels of productivity. There is no reason why such disciplines should not apply to JGN via the economic regulatory process.

The EMRF also notes that JGN's revised proposal includes a request for approval of additional expenditures for three new opex step changes. The EMRF considers two of these step changes may be prudent, but is not in a position to comment on whether the proposed costs are efficient. In particular, the EMRF has investigated the proposed increase in cost because of new B2B arrangements to enable harmonization of market interfaces and procedures across the east coast markets.[56]

More generally, the addition of new opex items highlights even more strongly the importance of ongoing productivity improvements in the fundamental operations of the business.

3.2 JGN's opex proposal and the AER's response

3.2.1 An overview of JGN's proposals and the AER's draft decision

JGN's initial proposal was for a total opex allowance of some $789.3 million ($2014-15) (excluding debt allowance). The AER draft decision did not accept this proposal and provided an opex allowance of $779.7 million, a difference of around 1%.[57]

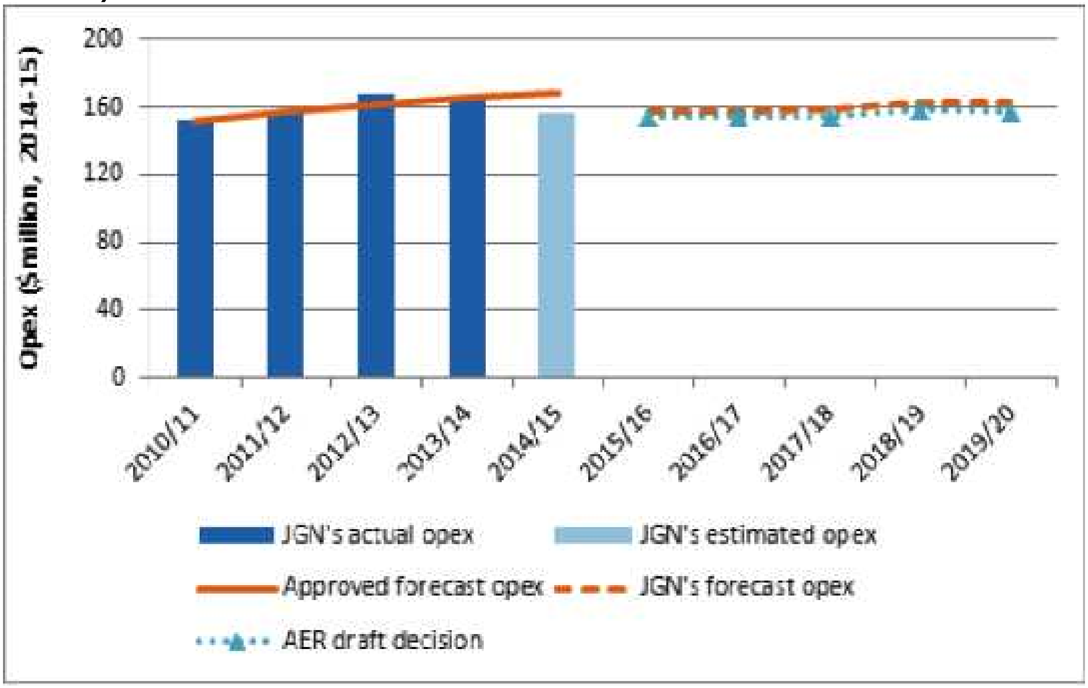
In its revised proposal, JGN proposed a somewhat higher opex of $805 million ($2014-15).[58] The revised proposal is around 3% higher than the AER's draft decision. This is largely because JGN has added three changes in circumstances in its revised proposal, namely:

- Gas quantity input audit
- Meter asbestos cover removal program
- B2B harmonization.

Figure 7 illustrates the allowed and actual opex for AA1, as well as the forecast opex for 2015-20 (AA2).

[56] Discussions with AEMO staff who confirmed that the harmonization project has been accepted and will be in place during 2016. Major changes will be required in JGN systems and processes, although the project has a net benefit over the longer term and will facilitate retail competition.
[57] AER, *Draft Decision Jemena Gas Networks Access Arrangements,* Attachment 7, Operating Expenditure, Table 7-1, p 7-7. [AER, *Jemena Draft Decision,* Attachment 7]. The AER also notes that JGN updated its forecast opex after the initial proposal and before the draft decision – the figure of $789.3 million is the revised amount (see footnote 2)
[58] Jemena Gas Networks (NSW) Ltd, *2015-20 Access Arrangement Response to the AER's draft decision & revised proposal*, Public, 27 February 2015, Table 5-5, p 89. The figure of $805 million excludes debt raising costs.

Figure 7: JGN actual and forecast opex compared to AER approved opex ($ million, 2014-15)



Source: AER, *Draft Decision, Jemena Gas Networks (distribution) 2015-20*, Fact Sheet, p 2.
Note: JGN's forecast is based on its original proposal, JGN's revised proposal is around $3 million pa higher than illustrated in the figure.

For the current 2010-15 period, JGN proposed a total opex of $810 million ($2014-15), and the estimated total opex for that period is around 2% below that figure. This is, in large part, because of the expected reduction in opex in 2014-15 relative to the allowance.

JGN has proposed to use 2013-14 as the base year for its opex forecast, and to apply the AER's "base, step, trend" approach to the assessment of the prudent and efficient opex.

3.2.2 AER's Draft Decision

The AER's approach is to build up its own forecast of total opex, using its "base, step, trend approach", and then compare this forecast with JGN's forecast. If JGN's forecast is "sufficiently different" from the AER's then the AER will investigate the reasons for this difference and may conclude that it is not consistent with the opex criteria under the NGR.[59]

The AER concluded that there were only two major areas of difference between the AER's forecast and JGN's forecast. Noting that the AER has

[59] AER, Jemena *Draft Decision JGN 2015-20 Access Arrangement*, Attachment 7, November 2014, p 7-12.

not yet assessed the additional opex items included in JGN's revised proposal, the two areas identified by the AER are: [60]

- Rate of change – the AER does not accept JGN's proposed changes is not the best estimate; and

- Step changes – the AER does not accept a "step change" related to annual regulatory reporting.

The base year:

The AER accepted JGN's proposed base year opex for 2013-14, including JGN's adjustments to the base year for a change in capitalization policy.[61] Although the AER did not apply any benchmarking to the base year, its investigations showed no evidence that the opex in that year was "materially inefficient".[62]

Rate of change (trend):

The AER considered that JGN's proposed rate of change across the three components and concluded as follows:

- The AER was not satisfied with the rate of change in JGN's forecast of prices of labour and of materials;

- The AER accepted JGN's forecast of the rate of change in the outputs;

- The AER accepted JGN's forecast of the rate of change in opex partial factor productivity.

Step Changes:

In its initial proposal, JGN proposed step changes amounting to some $23.9 million ($2014-15). The AER accepted most of these step changes other than annual regulatory reporting cost claim by JGN. The AER stated that this was "not a new regulatory obligation".[63]

JGN's revised proposal adds another $12 million ($2015) to the proposed step-change for the three new projects.

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[60] Ibid
[61] ibid, p 7- 17. There was a transfer from opex to capex for a number of items, approximating $3.47 million/pa. The AER has assessed this change and believes it was appropriately undertaken by JGN.
[62] ibid, p, 7-16.
[63] Ibid, Table 7-5, pp 7-19 to 7-20.

Table 3 below summarises the proposed step change and AER's response to these proposals.

Table 3: JGN's proposed step changes and the AER's position ($million, 2014-15)

Proposed Step Change	**Amount ($m)**	**Draft Decision ($ m)**	**Reasons for draft decision**
Approved			
NECF	6.4	6.4	New regulatory policy
Customer Engagement	0.5	0.5	Was capitalized in 2013-14, now opex
Reset costs	7.9	7.9	Was capitalized in 2013-14, now opex
Additional marketing	6.6	6.6	Efficient response to market conditions
Insurance premiums	0.6	0.6	Prudent risk management
Total Approved	**23.9**	**23.9**	
Not Approved			
Annual reg reporting	1.9	0.0	Not a new requirement
Pending AER's decision			
Gas quantity input audit	0.14	?	
Meter asbestos removal	0.97	?	
B2B Harmonization	11.00	?	

Source: AER, *Draft Decision JGN 2015-20 Access Arrangement*, Attachment 7, Table 7-5, pp 7-19 to 7-20. The items and amounts listed under "pending AER's decision", are from JGN, *Revised 2015-20 Access Arrangement,* Appendix 5.04, "Operating expenditures step change report", Table OV-1, p iv.

JGN also provided four category specific forecasts as part of its "step change" forecast. These are: government levies, unaccounted for gas (UAG), carbon costs and debt raising costs. The AER accepted JGN's proposal for the government levies, JGN's adjusted carbon costs (post original proposal) and UAG costs. However, the

AER noted that it would update the UAG costs before the final decision, based on the final demand forecast.[64]

The AER provided an alternative cost for raising debt, using its standard debt costing approach based on the cost of debt for the benchmark efficient service provider.[65]

3.3 JGN's Response to the AER and Revised Proposal

3.3.1 Base Year:

JGN has provided updates of its 2013-14 base year actual opex. The EMRF does not comment on these updates but expects the AER will review the updates carefully given that any changes flow through to each year of the next period.[66]

3.3.2 Rate of change (trend):

JGN did not accept the AER's draft decision on the rate of change for labour and material costs. The revised proposal relies on an update of the BIS Shrapnel forecast as the best forecast in the circumstances.[67]

JGN also did not accept the AER's draft decision on the rate of change in outputs as JGN did not accept the AER's demand forecasts (see Section 5). JGN's revised proposal is based on its original proposal using updated demand and customer number forecasts.[68]

3.3.3 Step Changes

JGN accepted the AER's statement that there would be no substantially new information reporting requirements (compared to the base year, 2013-14) and removed that component of the step change in its regulatory proposal.[69]

With respect to the four additional categories, JGN responded as follows:

- Carbon costs were reduced following the repeal of the Clean Energy Act (which occurred after JGN's original proposal was submitted to

[64] Ibid, p 7-28. The agreed UAG rate is 2.24% (with different rates for Tariff D (0.45%) and Tariff V (5.44%) customers). The total UAG cost = UAG rate * quantity of gas * cost of gas. The final UAG cost will be updated in line with the forecast quantities and the cost of gas (which is confidential).
[65] Ibid, p 7-10.
[66] Jemena, 2015-20 Access Arrangement, revised proposal, February 2015, p 86.
[67] Ibid, p 84 – 85, Table 5-1 (@ 441).
[68] Ibid.
[69] Ibid, p 86 (@ 442 – 444)

the AER). However, JGN continues to apply the annual audit costs for the National Greenhouse and Energy Reporting (NGER) scheme. The AER has accepted these changes[70] (although the EMRF notes that the requirement for NGER reporting is being addressed at a government level as well and that the AER should review this allowance).

- JGN has updated its UAG forecast cost based on its most recent competitive tender price for UAG. As the cost information is marked commercial-in-confidence, EMRF relies on the AER to decide if this price is reasonable and the competitive tender process appropriate.[71]

- JGN does not accept the AER's views on debt raising costs, and by implication, the AER's overall model of debt costs for the benchmark efficient service provider. JGN continues to claim a higher allowance based on its own advice. [72]

3.4 EMRF response to the AER's draft decision and JGN's revised proposal

The discussion below is in two parts. In the first instance, the EMRF considers the overall outcome of the AER's decision.

3.4.1 EMRF's concern with JGN's overall opex productivity.

The EMRF is aware of the limitations of benchmarking the gas distribution businesses against each other, at this stage. However, the EMRF also believes it is essential to consider the trends in opex productivity by each business, particularly given the significant increases in capex which should, over time, lead to lower opex as older assets get replaced.

In its original submission the EMRF indicated that its principal concern with JGN's proposal was that its forecast productivity growth of just over 1% per annum did not demonstrate a sufficient commitment to reductions in opex, particularly given the current circumstances facing JGN.

For example, JGN reported in its initial proposal that its opex per metre of pipeline will decline as will its opex per customer over the forecast period, as set out in Table 4 below.

[70] Ibid, pp 87-88 (@ 456 – 459)
[71] Ibid, p 87 (@453 – 456).
[72] Ibid, p 86 (@445).

Table 4: Operating cost per metre & per customer site ($2015)

	2015-16	2016-17	2017-18	2018-19	2019-20
Operating cost per metre	6.12	6.06	6.05	6.17	6.09
Operating cost per customer site	127.27	124.24	122.45	123.38	120.51

Source: Jemena Gas Networks, *2015-20 Access arrangement information, PUBLIC, June 2014*, Table 7-4, p 80.
Note: The table is based on the original submission. While JGN's revised proposal includes changes in forecasts and in opex, the trend is still very similar.

The EMRF highlighted that while opex per customer was reducing by some 5%, opex be metre of pipeline was little changed.[73] The EMRF also highlighted that the costs per metre in 2009 (adjusted for inflation), before the start of the current period were significantly below the current cost per metre (in the order of around $5.20/metre inflation adjusted.

The EMRF also notes JGN's reference to the benchmarking work of Economic Insights, which indicated that JGN was performing reasonably well against its peers when relevant factors were taken into account (scale, customer density, network age and network fragmentation).[74]

The EMRF has examined more recent gas distribution partial productivity benchmarking for by ACIL Allen for ATCO Gas Australia as part of ATCO's proposal to the Economic Regulation Authority of Western Australia (ERA).[75]

While this research supports JGN's view that its opex productivity is similar to others, it also illustrates the EMRF's concern that there has been a general flattening or even decline in opex productivity (depending on the measure) over the last five or so years across all the gas distribution businesses including JGN. This opex decline has occurred despite the increase in capex allowances over the same period.

Figures 8 (opex per customer) and 9 (opex per TJ) illustrate this point.[76] Note that ACIL Allen have projected JGN's opex per customer and opex per TJ to 2020, based on the AER's Draft Decision for Jemena.

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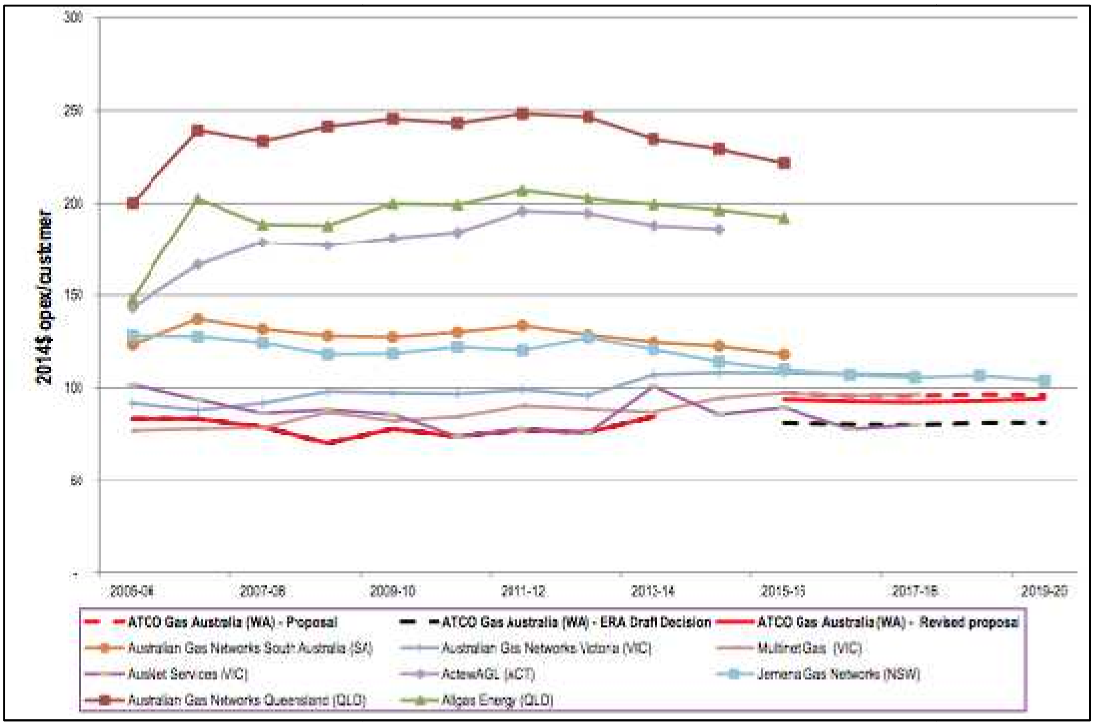
[73] See EMRF, NSW Gas Distribution Revenue Reset, A response by the Energy Markets Reform Forum, August 2014. p 35.
[74] Jemena Gas Networks, 2015-20 Access arrangement information, PUBLIC, June 2014, p 31 (@144).
[75] ACIL Allen, Gas Distribution Benchmarking, Partial Productivity Measures, November, 2014. The report updates an earlier benchmarking report dated March 2014. It is submitted by ATCO as Appendix 6.1 in the ERA's Draft Decision on ATCO's gas distribution network. See: https://www.erawa.com.au/cproot/13023/2/20141129%20GDS%20-%20ATCO%20-%20AA4%20-%20Appendix%206.1%20Gas%20Distribution%20Benchmarking%20Partial%20Productivity%20Measures%20Acil%20Allen%20November%202014.PDF
[76] Customer numbers and volume throughput are generally considered the main drivers of opex.

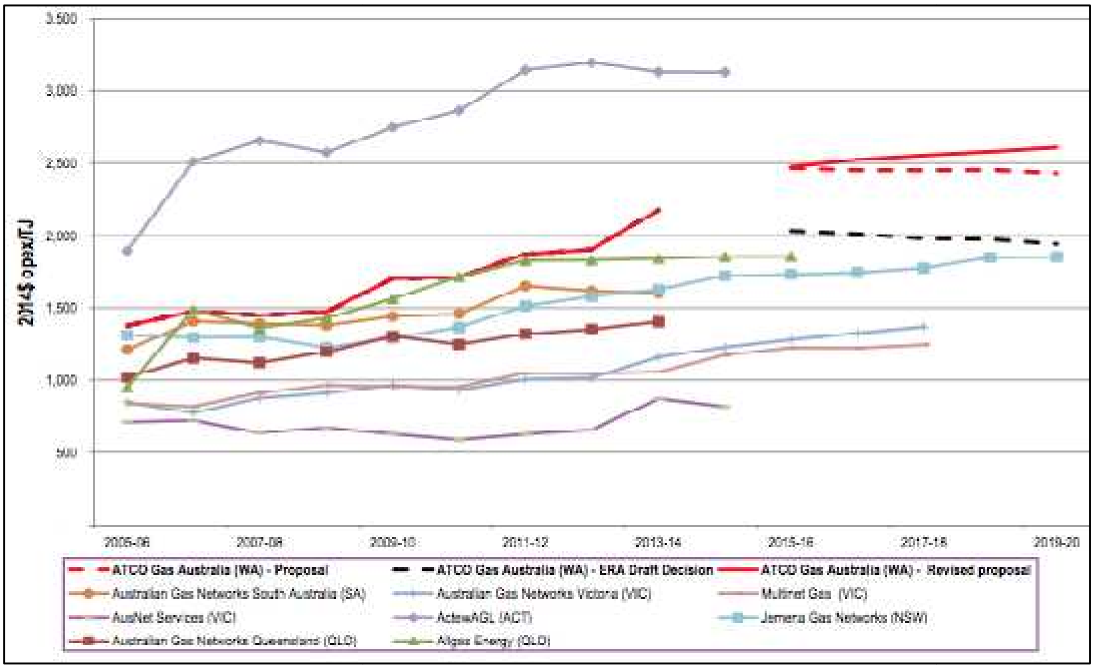
Given JGN's forecast of a continued growth in customer numbers but low energy growth, it is not surprising that opex per customer improves slightly on the per customer measure, but continues to deteriorate on the per TJ (volume) measure.

Figure 8: Opex per customer ($Sept 2014),



Source: ACIL Allen, *Gas Distribution Benchmarking*, Nov 2014, Figure 5, p 17.

Figure 9: Opex per Terajoule (TJ) ($ Sept 2014)



Source: ACIL Allen, *Gas Distribution Benchmarking*, Nov 2014, Figure 6, p 20.

The EMRF believes the industry regulators must take a more proactive stance on this issue, so that Australian energy networks productivity starts to improve, just as the EMRF's members have had to do in response to international pressures. The EMRF therefore, urges the AER to take a more proactive stance on the trend productivity coefficient than it has in its draft decision.

ACIL Allen's analysis, and in particular, its forecast based on the AER's Draft Decision for JGN strongly suggests that the AER"s overall opex allowance represents a conservative decision, that risks building in future cost pressures when the current interest rate "protection" is no longer there.

The EMRF, therefore, notes with some concern, that the AER considers IPART's study (which the EMRF referred to in a submission to the current period and referred to again in its original submission for this review) as not being relevant to this debate. The EMRF disagrees. The IPART study found that the Australian gas industry as a whole was more then 27% less efficient than their overseas counterparts.[77]

The EMRF continues to argue that this is likely to be still the case and this is supported by a number of subsequent studies. The gas networks are only part of this story of comparative inefficiency but that does not mean the issue can be ignored; it merely indicates that more work needs to be taken to update the IPART analysis.

Finally, the EMRF notes that JGN's revised proposal includes an opex forecast (including the new opex items) that is some 2% above the AER's draft decision. If the AER were to accept this proposal, the overall productivity outcomes described above – and in particular, the opex per customer, will continue its current level.

3.4.2 EMRF's view on specific aspects of the AER's decision & JGN's response

The EMRF acknowledges that the AER has addressed a number of the issues raised by the EMRF in its original submission. For example, the EMRF's concerns with the treatment of the carbon tax are adequately addressed in the Draft Decision and JGN's revised proposal.

Similarly, the EMRF has already agreed with JGN's proposal to set two separate UAG rates, and therefore, agrees with the AER's draft decision to accept JGN's proposal, including the rates identified by JGN.

[77] See EMRF, *NSW Gas Distribution Revenue Reset, A response by the Energy Markets Reform Forum, A*ugust 2014, p 42.

However, the EMRF would comment on the following specific aspects that are in addition to the concern set out above with the productivity coefficient in the trend analysis:

- The EMRF raised a query about the treatment of "disallowed corporate overheads". These overhead costs (JGN referred to these as 'enterprise support functions') were disallowed in the 2010-15 period reset decision. The EMRF believed there was a risk that these costs might be included in JGN's base year (2013-14) costs.

  It is not clear from the draft decision if the AER has investigated this issue. If not, EMRF requests the AER does so as part of its final decision. [78]

- The EMRF supports the AER's approach to assessing labour costs. The forecasts by BIS-Shrapnel that JGN relies on do not adequately reflect recent trends in wages (which are flat) and imply a real wage increase of over 10% for the 2016-2020 period and a nominal increase of over 28%.[79]

  The EMRF also does not support JGN's forecast of real increases in costs for materials. Given all the available evidence, the AER's assumption of a CPI increase is a reasonable, albeit conservative, forecast.[80]

  The EMRF also rejects JGN's comments about the currency movements and the effect this has on commodity costs for the network. As noted previously by the EMRF and the AER, a prudent network would be expected to hedge its exposures to currency movements.[81] In addition, the movements in commodity prices are very substantial and given this, an assumption of no real price increases is not only more preferable but also a more realistic forecast.

- The EMRF agrees with the AER's proposal to reduce debt raising costs. While JGN has rejected the AER's draft decision (as noted above), the EMRF reiterates its comments in its original submission. In that submission, the EMRF noted that JGN itself suggested it incurred no costs for raising debt (or equity) over the past five years.[82]

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[78] Ibid, p 37.
[79] Ibid, pp 39-41.
[80] Ibid, p 41.
[81] Ibid, pp 41-42.
[82] Ibid, p 47.

- JGN has sought, and the AER allowed, an increase of some 16% ($6.5 million ($2015)) in marketing costs over the base year allowance of just under $40 million ($2015). The AER states that around half of the total expenditure (some $25 million) is on rebate schemes.

  The EMRF sought a more detailed assessment of this marketing expenditure including the expected relationship between the rebates and the number of gas consumers.[83] Neither the AER nor JGN provided such an analysis for consumers to examine.

  The EMRF is of the view that "marketing" can become a "black hole", and needs to be constantly evaluated. The EMRF therefore expects that the AER will conduct a more detailed investigation as to:

  - what the marketing program is to achieve,
  - the past effectiveness of JGN marketing and
  - whether there is a net benefit to consumers of such marketing

prior to the Final Decision.

[83] Ibid, pp 48-49.

4 The Weighted Average Cost of Capital (WACC)

As JGN has made few changes to the approach it adopted to assessing the WACC in its revised proposal, the EMRF considers that many of the issues it raised in its comprehensive response to the initial proposal are still relevant to the revised proposal.

For this reason, a number of the issues will be summarized in this paper, and we refer the AER also to the EMRF's original submission for further detail. The EMRF is happy to meet with the AER to discuss these issues further before the AER's Final Decision, as the EMRF regards this as the most important – and contentious - component of the AER's economic regulatory decisions.[84]

The EMRF reminds the AER that consumers have been very much "on the wrong side" of the risks that emerged during the global financial crisis (GFC) and the regulatory decisions that were made in that period.

While consumers have seen prices increase at unprecedented rates, networks have enjoyed substantial increases in profits, much larger than required by the limited risks they face compared to their business peers.

The assessment of the WACC has been a major (if not the major) contributor to this outcome.

Many bodies, including the AEMC, the AER and consumer representatives, have committed substantial resources into amending the economic regulatory framework so that these mistakes are not repeated. The outcomes of this process are captured within the AEMC's rule changes and the AER's Rate of Return Guideline.

4.1 Summary of EMRF's response to JGN's WACC proposal & the AER's Draft Decision

In JGN"s initial proposal, JGN's proposed WACC was 8.67%, only 176 basis points below the AER's allowed WACC for the current period (2010-15), despite the significant reduction in interest rates and improved investment environment that now prevails.

The AER did not accept JGN's proposed WACC. The AER applied its Rate of Return Guideline[85] to the assessment of the efficient financing costs of a

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[84] EMRF, pp 64 – 97.
[85] AER, *Rate of Return Guideline* December 2014 and AER, *Explanatory Statement, Rate of Return Guideline*, December 2014. The AER's Rate of Return Guideline applied to electricity and gas distribution and transmission network companies.

benchmark efficient entity with a similar degree of risk, as required by the NGR.[86] The AER's draft decision allowed a WACC of 6.8%

JGN rejected the AER's draft decision. Applying basically the same methodologies as it did in its initial proposal, JGN proposed a WACC of 7.1%. The reductions in JGN's revised proposal compared to its initial proposal are very largely a reflection of the ongoing decline in the risk free interest rates and 10-year bond rates.

Table 5 below summarises JGN's initial and revised WACC proposal based on, inter alia, a different approach to the assessment of the rate of return on equity. The AER's assessment is also included. While JGN's revised return on equity is higher than the AER's, the revised cost of debt is lower.

However, this reduction in the cost of debt is only a reflection of the movement in 10 –year BBB bond rates between November and February. At any point in time, therefore JGN's approach will deliver a substantial premium over the AER's approach reflecting the higher cost of equity.

Table 5: JGN's proposal, AER's draft decision and JGN response

For 2015-20 period	**JGN (June 2014) %**	**AER (Nov 2014) %**	**JGN (Feb 2015) %**
Cost of Equity			
Risk Free Rate (RFR)	3.18	2.38	2.69
Market Risk Premium (MRP)	6.5	6.5	8.17
Equity beta (beta)	0.82	0.7	0.82
Total Cost of Equity	**10.71**	**8.1**	**9.87**
Cost of Debt (updated annually)	**7.3**	**5.93**	**5.33**
Nominal Vanilla WACC	**8.67**	**6.89**	**7.15**
Equity Risk Premium (ERP)	6.59	4.55	7.23
Debt Risk Premium (DRP)	3.18	2.38	2.69
Imputation Credits (Gamma) – value	*0.25 (25%)*	*0.4 (40%)*	*0.25 (25%)*

86 NGR, Rule 87 (2) (3).

The EMRF continues to support the AER applying its Rate of Return Guideline. This support for the application of the AER's Rate of Return Guideline is despite of the EMRF's view that it is conservative in its assessment of the risks facing the networks and that the relative "protection" of the networks from risks faced by business in general are not adequately captured.

The EMRF is also greatly disappointed by the failure of the networks, including JGN, to accept the AER's Rate of Return Guideline approach. The Rate of Return Guideline was developed by the AER after some twelve months consultation with all stakeholders and considerable input from various financial experts. It provides a transparent, consistent and predictable framework for both investors and consumers.

The alternative approach set out by the networks (including JGN), particularly with respect to the cost of equity, is complex, lacks transparency, and requires multiple subjective assumptions as inputs. Nor has it been subject to open consultation with consumers.[87]

In the view of the EMRF, the networks' approach can be adapted to produce a wide range of "feasible" WACC outcomes, leaving it open for a given network to manage the outcomes in their favour. It is patently clear therefore, that such an approach should not be adopted by the AER.

The EMRF, therefore, urges the AER to maintain its stance and continue to apply the Rate of Return Guideline to the assessment of the efficient financing of the benchmark efficient entity.

4.2 JGN's Rate of Return Proposal (including revised proposal)

4.2.1 JGN's cost of equity proposal

In its rate of return (WACC) proposal, JGN proposed a significant departure from the AER's Rate of Return Guideline, particularly with respect to the cost of equity.

That is, JGN adopted the multi-model approach to assessing the rate of return on equity. JGN's revised proposal follows the same approach, although in this instance, JGN has given equal weights to the four models it considers relevant to assessing the cost of equity.[88] That is, JGN applied a 25% weighting to each of the following models:

[87] Or at least consultation with consumers after the completion of the Rate of Return Guideline.
[88] The EMRF pints out that as well as JGN varying its weightings, other networks have applied different weights to each model, reinforcing the EMRF view that the approached used by networks

- S-L CAPM (JGN's version – see below);
- Black CAPM;
- Dividend Growth Model (DGM); and
- Fama-French 3 factor model (FF).

In its original return on equity modeling, JGN had allocated the following weights (in order of above): 15%, 25%, 25% and 35%. JGN claimed this was on the basis of the strength of each of the models, notwithstanding that the AER found the Fama-French model to provide unreliable outputs in the Australian setting.

As noted above, in the revised proposal, JGN applied an equal weighting to each model, in this instance on the basis that it was appropriate to apply equal weightings given the strengths and weaknesses of each model.

However, further examination points to an alternative explanation. In its revised approach, JGN revisited the S-L CAPM parameters. JGN concluded that while they had "accepted" the AER's Rate of Return Guideline for the market risk premium of 6.5% (a conservative number, but one within the range that was widely supported in theory and practice), a new analysis of the data suggested that the MRP was 8.17%.

When combined with the beta coefficient advised by SFG Consulting of 0.82, JGN stated that the S-L CAPM cost of equity was 9.2% compared to the AER's value of 8.1% based on a MRP of 6.5% and more conservative beta value of 0.7.

It is not surprising that the EMRF is skeptical of the reliability and transparency of the multi-model approach.

4.2.2 JGN"s cost of debt approach

In its initial proposal, JGN largely adopted the approach to assessing the cost of debt set out in the AER' Rate of Return Guideline, including:

- The assessment of both the risk free rate and commercial bond rate on the basis of 10-year Commonwealth Government bonds (CGS) and 10-year commercial bonds (respectively);

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for assessing the cost of equity is open to manipulation and displays a lack of transparency and consistency

- The use of an average of the Reserve Bank 10 year “BBB” commercial rated bonds and Bloomberg fair value curve for “BBB” 7 year bonds extrapolated to 10 years (note: in both instances “BBB” includes a range of bonds from BBB+ to BBB-);

- the cost of debt transition arrangements and the proposal to update the cost of debt each year, using a pre-set transparent formula.

However, JGN’s proposed to vary the Guideline approach to setting the averaging period for the relevant bonds.

The Guideline requires the network to specify the averaging period for the annual update of the cost of debt at the start of the regulatory period. The same averaging period would apply to each of the annual updates in that regulatory period.

JGN proposed a different methodology. JGN’s proposal enabled the network to specify each year its proposed averaging period for that year.

In its revised proposal, JGN proposed another significant change to the AER’s cost of debt transition methodology that was set out in the Guideline, and that JGN had previously accepted as reasonable. JGN proposed that the risk free interest rate component of the cost of debt should be updated each year, but the debt risk premium should remain constant through the regulatory period.

4.2.3 JGN’s view on the risks of a gas distribution network

More generally, JGN disputed the assumption that the efficiently financed benchmark efficient gas distribution entity should be assessed as having the same level of risk as electricity distribution businesses. JGN states that this is because the gas distribution businesses are under greater commercial risk than electricity distribution businesses, particularly with the forecast increase in gas prices.

JGN proposed that the benchmark efficient gas distribution business should be allowed a higher equity beta than the average; and a BBB credit rating for the purposes of assessing the cost of debt.

4.3 The AER’s Draft Decision on the Rate of Return

The AER has rejected JGN’s proposal and applied the methodology and parameter settings in the Rate of Return Guideline to assess both the cost of equity and the cost of debt.

4.3.1 Return on equity

AER affirms its decision to apply the Rate of Return Guideline and parameters to decide JGN's WACC:

> In its draft decision, the AER affirmed that, **having considered a large amount of information, including various equity models** [EMRF emphasis], the evidence suggests the S-L CAPM is the "superior model in terms of estimating expected equity returns".[89]
>
> Similarly, the AER confirms that its input parameters, the market risk premium (MRP) and equity beta, have been determined "**after considering a range of relevant material**…"[90] [EMRF emphasis]
>
> The AER further states that "employing our foundation model approach and using the S-L CAPM as the foundation model, in the context of the vanilla WACC formula, is expected to lead to a rate of return that meets the allowed rate of return objective".[91]

What is the AER's implied equity risk premium (ERP):

> The ERP measures the premium that equity investors require over the risk free rate in order to invest in the company. It presents more of a "top-down" view, albeit it is mathematically the equivalent of the MRP * the equity beta.
>
> A key criteria for assessing whether the AER"s draft decision on the overall return on equity is reasonable, and meets the requirements of the NGL and NGR, is to consider whether the ERP is reasonable in the circumstances.
>
> Figure 10 below, illustrates the AER's draft decision on the ERP (4.55%) within the context of the range of data sources available to it. Figure 10 also illustrates the difference between the ERP and the debt risk premium (DRP). The DRP measures the premium debt providers seek over the risk free rate for debt.
>
> Based on this analysis, and following further assessments of the alternatives provided by JGN, the AER concludes that its calculated cost of equity (to be updated in the final decision) is more consistent with the allowed rate of return on equity and, therefore, represents a preferable decision to JGN's proposal.

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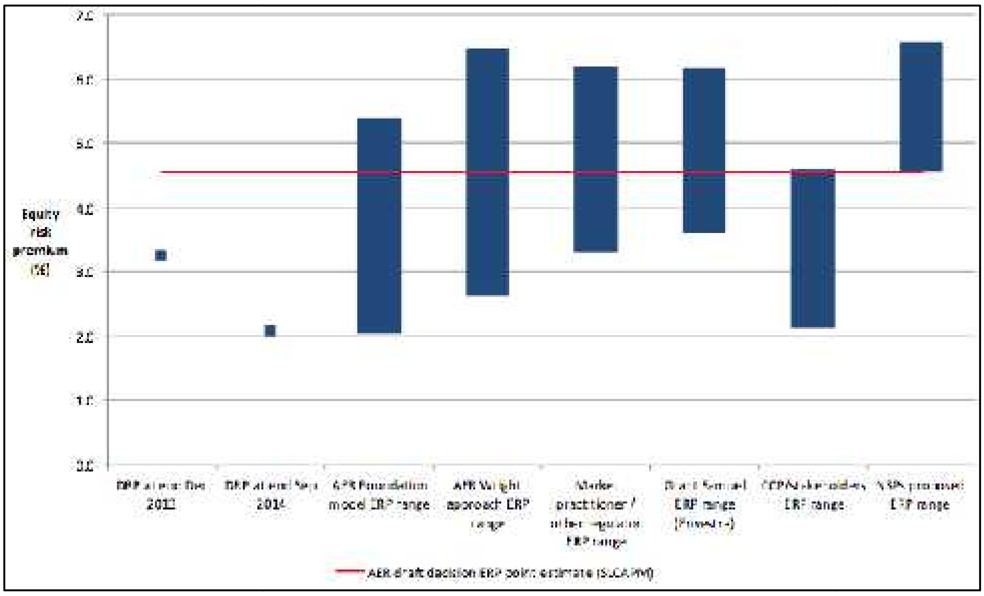
[89] AER, *JGN Draft Decision, Overview*, November 2014, p 37.
[90] Ibid.
[91] Ibid.

Figure 10: The AER Draft Decision on the ERP compared to other sources of information.



Source: AER, *JGN 2015-20 Draft Decision, Overview*, Figure 8-2, p 38. The difference between the AER's draft decision and stakeholder views is largely a result of the different views of the equity beta value. Stakeholders generally supported the AER's Rate of Return Guideline approach for this draft decision.

4.3.2 Return on debt

The AER largely affirms its approach set out in the Rate of Return Guideline.

The AER has confirmed its approach as set out in the Rate of Return Guideline and associated Explanatory Statement, namely:

- Trailing average approach to assessing the cost of debt;
- The assumed credit rating of BBB+ for all gas and electricity transmission and distribution businesses including JGN; and
- The use of 10 year risk free Commonwealth Government Securities (CGS) bonds and 10 year commercial bonds

Following further assessment, the AER advised in the draft determination that both the RBA 10-year commercial bond series and the Bloomberg fair value curve (7year extrapolated to 10 years), while robust and repeatable had limitations. Therefore, the AER proposed to use the average of the two series for the coming determinations on the cost of debt.

The AER did not accept JGN's proposal for updating the averaging period each year. The AER's draft decision requires JGN to specify its averaging period at the start of the regulatory period and continue that for the remaining years. This was to address consumer concerns with the ability to "cherry pick" the averaging period to maximise JGN returns.

4.3.3 Imputation Credits (gamma)

The AER has modified the value of imputation credits set out in the Rate of Return Guideline. The Guideline proposed a value of gamma of 0.5; the AER draft decision adopts a value of 0.4. The AER states that it has re-examined the relevant evidence and estimates and considered new advice and evidence provided since the guideline was published.

This draft decision on gamma means that the effective cost allowance for tax increases from 15% of net profits before tax to 18% of net profits.[92]

4.4 JGN's Response to the AER's draft decision

In its response to the AER's draft decision, JGN has rejected the AER's approach to the cost of equity and many aspects of the AER's approach to the cost of debt (including areas that JGN agreed to in the first instance). JGN also rejects the AER's proposed gamma.

The summary below sets out some of the key points made by JGN in rejecting the AER's draft decision and amending JGN's initial proposal: [93]

4.4.1 JGN's view on AER's draft decision - return on equity

- The AER has erred in its apparent assumption that one return on equity model (S-L CAPM, the foundation model) is superior to others; the AER does not recognise the limitations of the S-L CAPM that leads to an underestimation of the efficient cost of equity;

- The AER has failed to have regard to all the relevant evidence, and/or failed to given relevant evidence a meaningful role in their decision on the cost of equity and the MRP;

[92] The effective tax rate is calculated as follows. Effective tax rate = corporate tax rate * (1 – gamma); ie = 30% * (1-0.4) = 18%.
[93] Summarized from JGN, Response to the AER's draft decision, February 2015, pp 96 – 97 (return on equity issues) and pp 97-98 (return on debt issues).

- The AER has erred in its estimation of the equity beta. In addition, the AER errs in applying the same equity beta is applied to gas and electricity networks; gas networks face different risks;

- The AER's return on equity is not consistent with other market evidence.

As a result of these claims, JGN states that JGN's original proposal for assessing the cost of equity is the approach that is most consistent with the rate of return objective, subject to changes in the weighting of the four equity models.

4.4.2 JGN's view on the AER's draft decision - return on debt

- The AER errs in setting the credit rating for a gas distribution network businesses at BBB+, contrary to empirical evidence;

- The AER should not require JGN to nominate future averaging periods for subsequent years rather than updating the averaging period each year (as JGN proposes);

- The AER should not decide in advance that the annual updating of the cost of debt should be on the basis of a simple average of the RBA and Bloomberg curves, but rather, the data source should be selected at the time of estimation each year;

- The AER's methodology in extrapolating the RBA monthly yield data and Bloomberg's 7-year fair value curve and its proposed method for forecasting inflation are in error; and

- The AER should amend its approach to transitioning to the trailing average (this is contrary to JGN's original position). The AER should adopt a "hybrid" approach which transitions the risk free rate over a 10-year period, while the DRP is simply rolled forward.

4.4.3 JGN's proposal for Imputation Credits (Gamma)

In both the original proposal and the revised proposal, JGN is proposing a value of gamma of 0.25 calculated as the product of a distribution rate of 0.7 and a utilization rate of 0.35.

JGN therefore agrees with the AER's distribution rate but disputes the AER's utilisation rate (of 0.7) rate. In coming to a figure of 0.35 for the utilisation rate, JGN has relied on the implied market value studies, and in particular, the 'dividend drop off" series of studies, conducted by SFG

Consulting (SFG). JGN's approach is very similar to other NSPs in this area.

4.5 EMRF's Response to the AER's Draft Decision and JGN's Response.

As indicated above, the EMRF's response to the initial JGN proposal forms part of this current response to the AER's Draft Decision and JGN's response to the AER's Draft Decision.

4.5.1 EMRF response to JGN's original proposal

In particular, in its submission to the AER, the EMRF considered that the key issues with JGN's proposed rate of return were as follows:[94]

- JGN's proposal departs from the Rate of Return Guideline without adequate reason and without consultation with other stakeholders;

- The alternative method for calculating the cost of equity (the "multi-model" approach) produces unreasonable results for a low risk business. The method is complex, lacks transparency and requires multiple assumptions and arbitrary allocation of weightings;

- The multi-model approach includes, and places greatest weighting on, the Fama-French model of equity costs; the AER carefully reviewed this model in the development of the Guideline and found it did not provide consistent results in the Australian setting;

- The value of the equity beta used by JGN has been calculated using an empirical study heavily weighted towards US vertically integrated utilities and has only passing relevance to Australian utilities, especially now there is considerable data available on Australian utility performance. The empirical studies failed to incorporate data from more relevant jurisdictions such as the UK, NZ and Ontario (Canada);

- The networks proposed model did not sufficiently allow for the specific aspects of the regulatory regime that minimise risk, including:

    - Move from the "on the day" to trailing average assessment of the cost of debt (over a 10 years period);
    - Annual updating of the cost of debt; and

[94] See: EMRF, Submission on JGNs Access Arrangement Proposal, August 2014,

- Preservation of the value of the asset base by automatic CPI indexing and recovery of new capex investment.

The first two items above are part of the new regulatory framework, and provide a mechanism where networks can more readily match the allowed cost of debt with their actual cost of debt over the regulatory period.

- JGN's assessment of the value of gamma failed to acknowledge the additional work conducted by the AER, and therefore incorrectly relied too much on the earlier dividend drop-off studies to assess the dividend utilisation rate.

In addition to these issues raised in the EMRF's original submission, there are some particular issues that the EMRF highlights to the AER.

4.5.2 Is the overall rate of return consistent with the rate of return objective in the NGR and with the NGO?

As a general comment, the EMRF would note that the AER's current approach is, at least in the first year, quite similar to the earlier regulatory approach, although there is an upward bias in some parameters and a better coverage of risk (see above). The EMRF would also note that the network business were able to make above expected returns under the earlier regulatory framework used - this provides evidence supporting the current AER approach.

The historical assessment, therefore, suggests that the outcome of the AER's approach, taken as a whole, will be favorable to the networks and provide sufficient funds for the networks to continue to invest at an efficient level in their networks.

Although JGN's revised proposal provides for a lower WACC than its initial proposal, this is simply a reflection of the reduction in the risk free rate and the 10-year commercial bond rates since the original JGN proposal. Assuming efficient borrowing and interest rate and dollar rate hedging strategies, reductions flowing from these external movements will flow through to the network businesses.

Given the continued decline in the risk-free rate, however, it is also important to separately consider the reasonableness of the ERP and the DRP (which represent the premium equity and debt holders require over and above investment in risk-free assets) separately from the impact of the general interest rate movements.

The plausibility of JGN's ERP and the differential between JGN's ERP and DRP are discussed below.

4.5.3 Is the level of the ERP in JGN's revised proposal plausible?

JGN's proposals and, in particular, its revised proposal, result in an ERP that seems well in excess of a reasonable premium to investors for investing in low risk assets with stable cash flows and a protected asset base value.

The EMRF therefore considers that JGN's return on equity proposal is significantly less likely to contribute to the achievement of the allowed rate of return objective than the AER's draft decision.[95]

Table 5 above, illustrates these issues.

JGN's initial WACC proposal implied an ERP of 6.59%, a relatively high figure given the evidence provided by the AER in Figure 10 above.

However, it its revised proposal, JGN has gone even further with an implied ERP of 7.23%. This latter figure is now well above all the observations in Table 5. It is also substantially higher than the ERP of 5.2% that was set by the AER in 2010 for the current period, and which was applied in considerably more volatile market conditions.

JGN provides no satisfactory answer to the question of why the ERP should have risen in the period between May 2014 and February 2015 and why it should sit at a level that is well above historical observations.[96]

The EMRF also draws the AER's attention to a 2013 survey by KPMG on valuation practices in Australian businesses.[97] The survey included (inter alia) a question on the equity market risk premium (MRP) used when applying the CAPM model (the most popular model used for valuation purposes). KPMG concludes; [98]

> *Survey participants overwhelmingly are using an EMRP for Australia of 6 per cent with some bias towards 7 percent. A particularly interesting aspect of these results in the concentration of Australian premium around 6 per cent compared to a wider range for the US and UK markets, and against evidence that the rate which prevailed*

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[95] NGR, Rule 87 (6).

[96] Or at least, JGN only explains this in the context of the output of their various economic models of the market risk premium (MRP). It does not explain it in terms of general economic drives – so there is no confidence that this is any more than just a convenient modeled output at one point in time. The EMRF would look for an explanation in terms of underlying trends in the real world.\.

[97] KPMG Corporate Finance, Valuation Practices Survey 2013, Australia, April, 2013. The survey included investment banks, professional service firms, and infrastructure funds http://www.kpmg.com/au/en/issuesandinsights/articlespublications/valuation-practices-survey/pages/valuation-practices-survey-2013.aspx

[98] Ibid, p 16

> *through the first half of the twentieth century is no longer relevant in the twenty-first. … over time, the observed* ***average risk premium for the domestic market has declined significantly*** *and averaged just 4.3 per cent over two decades to 2011, notwithstanding the impact of the GFC.*

KPMG also notes that there is good reason to believe that a more appropriate figure for Australia looking forward would be closer to 5 per cent.[99]

4.5.4 Is the spread between the ERP and the DRP in JGN's proposal plausible?

In addition, JGN's revised proposal suggests a very significant spread between the ERP and the DRP. In its revised proposal, JGN is implying that there is a spread of 4.54% between the ERP and the DRP (7.23% versus 2.69%).

Again, this is higher than in JGN's original proposal which showed a spread of 3.4% between the ERP and DRP. It is also much higher than the ERP-DRP gap in the AER's 2010 decision (1.03%), although it does not seem that JGN had difficulty raising additional funds during the current period.[100]

It is difficult to see how such a high premium for equity over debt is justified in the current market conditions. If it was really the case that equity was 454 basis points more expensive than debt (and taking into account the different tax treatments of equity and debt), the EMRF would expect to see the networks reverting to higher levels of debt (as they did in the past where gearing of >80% was being used by some utilities), but there is no evidence of this occurring; in fact gearing has, if anything, fallen in more recent times.

This issue of the premium of the cost of equity over cost of debt was examined by the AER in its final decision on Envestra Limited (Envestra).[101] The AER concludes that comparisons between the debt and equity premiums should be used with caution and more as a test of the reasonableness of the premiums.

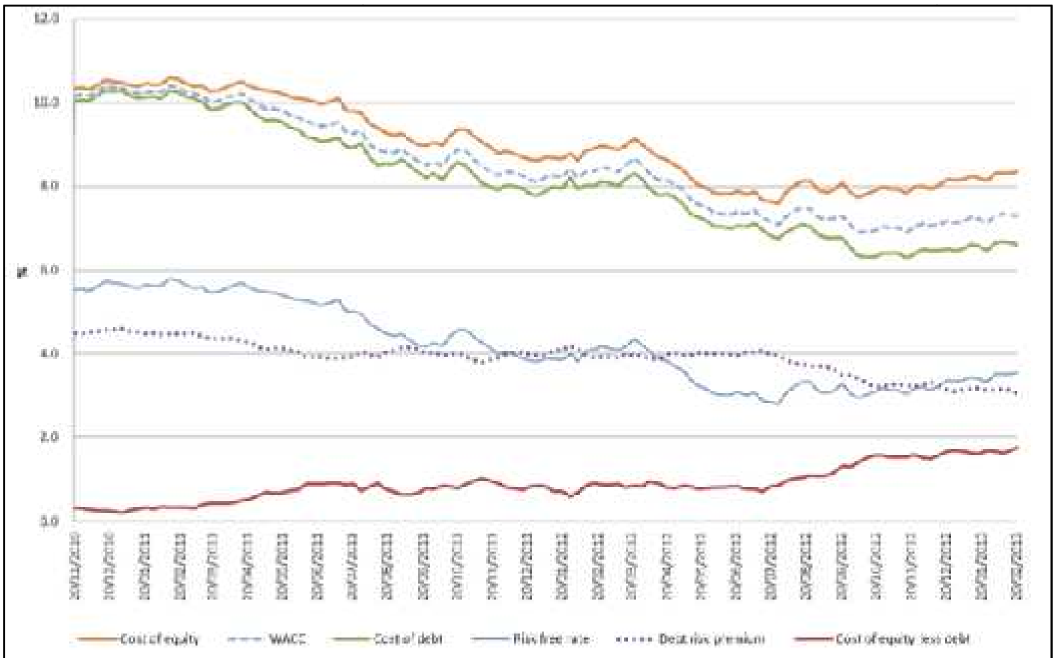
Nevertheless, the AER concludes that its analysis of historical spreads between debt and equity premiums: "provides the AER with some comfort

[99] Ibid, p 17.
[100] Following the successful appeal to the Tribunal by JGN, the final rate of return allowance for JGN in 2010 was 10.43%, with an ERP of 5.2% and a DRP of 4.17%.
[101] AER, *Access arrangement final decision, Envestra Ltd 2013-17, Part 3: Appendices,* Appendix B, pp 65-68

the current spread between its allowed returns on debt and equity are reasonable".

Figure 11 below, from the AER's Final Decision on Envestra illustrates this analysis and demonstrates that there was no spread between debt and equity that was greater than 2% (from November 2010 to February 2013). Envestra has had no difficulty raising debt funding during that period and in the recent sale of Envestra, was valued at a premium to RAB.

Figure 11: Comparison between the AER"s estimates and the costs of debt and equity



Source: AER analysis.
Note: The cost of debt in the above chart is estimated using the paired bonds approach adopted in this decision. The specific bonds reflect those used in the AER's recent final decision for Powerlink. This chart would not change materially if the paired bonds sample were updated. The start date for the chart reflects the availability of bond data required to implement this approach. Further details of the AER's approach to estimating the cost of debt are in section 5.3.5 of the attachment.

Source, AER, *Access arrangement final decision*, Envestra, Figure B.6, p 66.

In practice, therefore, the EMRF would argue that JGN's return on equity in its revised proposal, is an artifact of the complex modeling of equity costs and is not consistent with the cost of the efficient and prudent financing of a regulated gas distribution business.

4.5.5 Is the AER's overall draft decision on the WACC more reasonable in current market conditions?

Not surprisingly, the AER's draft decision implies a significantly lower ERP of 4.55% and a gap of 2.17% between the ERP and the DRP.

The EMRF is also cognizant that the AEMC's amendments to the NGR (and NER) were designed to allow the AER greater discretion to use its judgment and to consider the reasonableness of the total rate of return outcome. Similarly, the changes to the NGL (and NEL) require the Tribunal to focus its decisions on the overall totality of an AER's decision rather than focusing on a specific element of the AER decision.

For instance, the NGR states that both the return on equity and return on debt must be estimated such that "it contributes to the achievement of the allowed rate of return objective.[102]

Similarly, the amendments to the NGL require the Tribunal to consider any appeal in terms of whether the application would result in a "materially preferable" decision,[103] based on considering "the reviewable regulatory decision as a whole".[104]

The EMRF therefore considers the AER's draft WACC decision is a more preferable decision with respect to the NGO. Overall, the AER's decision is more reflective of the "prevailing" market conditions, and better contributes to the achievement of the rate of return objective in the long-term interests of consumers.

4.5.6 What does information from the market suggest as reasonable and consistent with the efficient financing costs?

4.5.6.1 *Why should the AER consider additional market information?*

> The EMRF has concluded that the AER's draft WACC decision is a more preferable decision than JGN's revised proposal in the current market conditions. However, the EMRF has also briefly considered other market data and believes this provides useful information to the AER, particularly given JGN's suggestion that the AER's allowance will not provide sufficient funds to enable investment in the reliability and safety of the gas network.
>
> The EMRF has also noted the recommendations of the Consumer Challenge Panel (CCP) for the AER to take more heed of actual market data about the regulated network companies as one factor in its assessment processes.[105]

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[102] NGR, Rule 87 (6) and (7).
[103] See NGL, subsection 246 (1a) and subsection 259 (4a). The former refers to the grounds for appeal, the latter refers to the Tribunal's considerations in making a decision.
[104] NGL, Subsection 259 (4b) (c).
[105] See Consumer Challenge Panel, *Smelling the Roses and escaping the rabbit holes: the value of looking at actual outcomes in deciding WACC*, Advice to the AER Board, July 2014.

The EMRF set out a number of examples of useful market data in its original submission and it refers the AER to these examples in the first instance.[106]

For example, the EMRF highlighted the very substantial profits and asset value growth already enjoyed by the owners of JGN. As evidence of this, the EMRF pointed to both the annual report of JGN's part owner and more generally, the considerable premium (RAB multiples) paid by purchasers of Australian network assets, including purchases occurring after the finalization of the Better Regulation guidelines[107].

Additional "real world data" examples are set out below. The EMRF does not claim that this information is comprehensive, but considers it does point to some of the issues faced when the debate is centered on theoretical concepts rather than actual experience.

4.5.6.2 Financial Reports (March, 2013 -, March 2014)[108].

The following information comes from the most recently available financial report from JGN's parent company, SGSP.

- Standard & Poor (S&P) most recent rating of SGSP was BBB+ and Moody's most recent assessment was Baa1 in December 2013.[109] These ratings have not been changed following the AER's draft decision for NSW where the AER applied its Rate of Return Guideline;

- The post-tax discount rate used by SGSP reflects current market assessments of the time value of money and the risks specific to the assets. The annual financial reports set out the

[106] For example, see EMRF, Submission on Jemena's 2015-20 Access Arrangement Proposal, August, 2014, pp 93 - 95

[107] That is, the EMRF assumes these buyers would have conducted due diligence and still decided that above normal profits could be made from the operation of the regulated network assets. For instance, in March APA offered to purchase Envestra at a multiple of enterprise value to regulated asset base of nearly 1.4, Cheung Kong Group (CKI) won the sale with an offer multiple of nearly 1.5 in May 2014. See http://www.ft.com/cms/s/0/b0bfff42-e7c1-11e3-9af8-00144feabdc0.html#axzz3UtW3ZXVi

[108] SPI (Australia) Assets Pty Ltd, *Financial Report, Year ended 31 March 2013*. SGSP (Australia) Assets Pty Ltd (formerly known as SPI (Australia) Assets Pty Ltd), *Financial Report, for the Year Ended 31 March 2014.* The sale of 60% of the SPI business in Australia and New Zealand to State Grid International Development Australia Investment Company Limited was completed in 3 January 2014 following its announcement of the Transaction in 2013. The company as a whole now operates as SGSP (Australia) Assets Pty Ltd, and includes gas distribution and transmission assets, electricity distribution and a service company Zinfra.

[109] Ibid, p 2. S&P had downgraded the company (of which JGN is part) to BBB when the transaction was first announced but upgraded it again based on "its revised corporate rating criteria". Moody's had rated the company A3, and downgraded to the highest B grade, Baa1.

following discount rates for each of its business units. Notably, SGSP does not distinguish between its electricity and gas utilities in terms of its internal discount rates.

Table 6: SGSP post-tax discount rate by business type

Business Segment	**2014 %**	**2013 %**	**2012 %**
Gas, Water & Electricity Distribution	6.28	6.69	6.89
Gas Transmission	6.53-7.93	6.93-8.33	7.13-8.53
Infrastructure Services (Zinfra)	10.86	9.07	9.30

Source: 2014 and 2013 figures from SGSP Financial Report, Note 4 (3), p 25. The 2012 figures are sourced from SPI (Australia) Financial Report, Note 4 (3), p 24.

- Around half of SGSP's total borrowings are in the form of a trust loan from a related entity, and are non-interest bearing. The trust loan of some $A4.4 billion (as at March 2014) is payable at call but secured by a letter of undertaking from parent companies.[110]

- The company pays no tax in Australia and there are no franking credit balances in 2012, 2013 and 2014.[111]

4.5.6.3 Other Recent Market Data

In addition to the sale of Envestra at a significant multiple to RAB (around 1.5), the APA Group has successfully raised $US3.7 billion of long-term debt finance in March 2015 in both the US and Euro markets – after the AER's Draft Decisions were published.

The proceeds are to be used for "completing the purchase of the previously announced QCLNG Pipeline acquisition, and for general corporate purposes", suggesting a higher risk profile than the regulated assets alone. [112]

The US notes were for 10 and 20-year maturities at a fixed coupon of 4.2% and 5% respectively. The Euro notes were for 7, 12 and 15-year maturities at a fixed coupon rate of 4.2%. The APA Group chief financial officer was quoted as saying 'that the company was

[110] Ibid, Note29 (f).
[111] Ibid, note 9, p 33 (2014 Financial statement); note 9, p 35 (2013 Financial statement).
[112] APA, media releases: APA Group Euro and Sterling MTN Issuance, 16 March 2015; APA Group US 144A Issuance 17 March 2015. http://www.apa.com.au/investor-centre/news.aspx

pleased with “very strong interest” from debt investors attracted to APA’s portfolio of long-life stable infrastructure assets.’[113]

Similarly, in a recent article on potential buyers of Australian gas assets, it was noted that:[114]

> *An appetite for infrastructure assets from super funds and other large investors has surged globally since the financial crisis because the prices of such investment are less volatile than equities, while earnings tend to increase steadily.*

The comments from APA, and the quotation above, both reflect the strong interest from overseas investors (such as superannuation funds) and local infrastructure companies in acquiring gas network (and electricity network) assets. As a result, APA group was able to successfully raise a large amount of long-term funds (up to 15 years) at a relatively low interest rate of 4.2%, although rated BBB/Baa.

Importantly, this interest and the new data has also occurred after the AER’s Rate of Return Guideline was published and, in some cases, after the AER’s draft decision on the NSW electricity distribution and NSW and Tasmanian transmission networks.

4.6 Other issues with the proposed WACC

While the EMRF’s focus is on the overall reasonableness of the overall return on equity and return on debt, there are a number of specific areas that the EMRF considers should be subject to further comment (in addition to the EMRF’s original submission).

4.6.1 The AER’s approach builds conservatism on conservatism

Despite JGN’s claim that the AER’s approach will not allow them to recover its efficient financing costs, the EMRF suggests that the AER’s Rate of Return Guideline approach is conservative, particularly given the protections provided by the regulatory regime to JGN”s revenue stream and asset base.

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[113] See Angela Macdonald-Smith, “APA Group locks in $US3.7b financing to avoid call on bridging loan, The Sydney Morning Herald, 17 March 2015. http://www.smh.com.au/business/apa-group-locks-in-us37b-financing-to-avoid-calling-on-bridging-loan-20150317-1m0y35.html

[114] Amanda Saunders, “ IFM Investors eyes Santos, Origin Pipelines”, Sydney Morning Herald, 4 March, 2015. http://www.afr.com/business/infrastructure/ports/ifm-investors-eyes-santos-origin-pipelines-20150304-13tgt0

The EMRF has noted of this in its original submission, highlighting the AER's propensity to select from the "top of the range" of outcomes in its empirical analysis of the MRP and the equity beta.

The EMRF considers that the AER has continued to adopt this "cautionary" approach in its reduction of the value of imputation credits (gamma) from 0.5 to 0.4.

For example, the AER's revised assessment of the franking credit utilisation rate is based largely on the "equity ownership approach, using an "all equity" analysis, with a utilization rate of 0.55 to 0.7 (0.7 was the rate in the Guideline).[115] This analysis in turn leads to a range of gamma between 0.3 and 0.5, with the AER selecting the mid-point.

However, it would seem that the AER's analysis makes the assumption that the benchmark efficient network business provides imputation credits to its shareholders in the same proportion to the entire cohort of the market ().7 distribution rate) and that the utilization of these credits (0.4) is also comparable.

The available empirical evidence on the energy utilities, however, indicates that the whole exercise may be largely irrelevant to the equity owners of utility stocks.

For example, the EMRF has considered the financial reports of the APA Group, Envestra Ltd (pre sale) and Jemena's parent company (SGSP).

None of these companies have a balance in their franking credit accounts. This is because they are paying minimal tax to the Australian Government and/or there is a high level of overseas equity in the business. Indeed infrastructure companies, whether owned by overseas companies or in Australia, are able to take advantage of beneficial tax write-offs and deferrals.

The EMRF is aware that the AER's model of the benchmark efficient gas business is a pure play gas business operating in Australia. Nevertheless, when considering whether to select a low or high value (in this between 0.3 and 0.5), consideration should be given to the actual industry practices.

[115] The AER assesses the value based on evidence from "all equity" and separately, from "listed equity". All equity has a higher utilization rate but lower distribution rate, so the product of each approach is very similar. The results cited herein refer to the evidence from "all equity". See AER, Draft decision, Jemena Gas Networks 2015-20, Attachment 4 – value of imputation credits, November 2014, Table 4-1 and 4-2, pp 4-14 and 4-15.

4.6.2 The requirement in the NGR (and NER) that the AER must have regard to relevant estimation methods, financial models, market data and other evidence.

Sub section 87 (5)(a) of the NGR states:

> *(5) In determining the allowed rate of return, regard must be had to:*
>
> *(a) relevant estimation methods, financial models, market data and other evidence;*

JGN has claimed that the AER has failed to have regard to this requirement in the NGR, particularly with respect to the assessment of the cost of equity. Other networks make similar claims.

The EMRF, however, considers that JGN misstates this issue. The AER did indeed have regard to many alternative financial models, estimation methods, market data; including the models that are currently used by JGN (and others) to assess the cost of equity.

The AER assessed all these different approaches over a 12 month period, prior to finalizing the Rate of Return Guideline.

Evidence for this can be found in the AER's Explanatory Statement to the Rate of Return Guideline and additional papers on the assessment of equity beta, imputation credits and the transitional arrangements. The networks were extensively involved in all these discussions and had the opportunity to provide submissions, as were all other stakeholders. The AER also regularly updated industry groups and the Customer Consultative Forum, to an unprecedented extent.

The Rate of Return Guideline was the "end result" of this consultation process. It represented the AER's considered views on the most appropriate approach to satisfy the allowed rate of return objective, the revenue and pricing principles and the NGO.

In doing so, the AER provided a measure of certainty on rate of return process and outcomes for both networks and consumers. The networks themselves at the start of the Better Regulation process sought this additional certainty.

The EMRF therefore finds JGN's claims to be disingenuous; the AER has had regard to relevant estimation methods, financial models, market data and other evidence. The AER has then used its judgment to decide which of these are "relevant" and for what purpose in its determinations.

To posit, as JGN (and other NSPs) appear to do, that the AER must revisit and review all possible material at each determination, is to make redundant the principle of having a guideline.

Similarly, it would introduce an unacceptable level of uncertainty to the investment market in general, consumers and other stakeholders if each determination became a new battleground to include any new version of any new model or new model specification that had emerged out of the economic academia. Such an approach is ripe for "cherry picking" models to fit the outcomes.

In saying this, the EMRF also has concerns about some aspects of the current Rate of Return Guideline (as discussed above). However, having established the Guideline after extensive consultation, it is appropriate for these issues to be considered again as part of the three yearly review of the Guideline required under the rules.[116]

Overall, the EMRF argues strongly that the AER has met its obligations under Rule 87 to consider different financial models, estimation methods etc; and it has done so during the development of the Guideline. Having done so, the AER must have the discretion to apply the Guideline unless there is a compelling reason to do otherwise.

JGN's claims with respect to the AER's lack of compliance with Rule 87 (5) lack merit. It is JGN who has not consulted with stakeholders regarding their alternative methods.

4.6.3 The selection of equity models by JGN and the uncertainty arising from the "weighting" of these models

As a participant in the Better Regulation process from its inception, the EMRFs affiliate, the MEU, is aware that the question of "weighting" different equity models (as part of a "multi-model" approach) arose very early in the process.

At the time, both the AER and consumer representatives requested that the proponents of the "multi-model" approach formalize how these models would be "weighted" in a way that would provide some reassurance to consumers and avoid the problem of "cherry picking". A very large concern here was that this "weighting" would vary from determination to determination, depending on the outcome of each model.[117]

However, no objective decision criteria were defined for allocating weights by the networks (or JGN representatives) other than the point of time

[116] See NGR, Rule 87 (16) (a)
[117] For instance, it was noted that the Dividend Growth Model can sometimes produce very low MRP and/or cost of equity as well as very high outcomes (from 2% to 14%).

assessment by the various consultants to the networks, and there was no assurance given that these weightings would not change from one determination to the next.

JGN's proposal demonstrates the difficulties that can be posed by this issue. In its initial proposal, JGN proposed different weightings for the four different equity models that it included in its assessment.

In its revised proposal, however, JGN assigned equal weights to each model. The initial weighting was claimed to be on the basis of the relative robustness of the models,[118] the revised proposal reflected a changed view that averaging was appropriate as all the models had their strengths and weaknesses.

Table 7 below summarises JGN's two approaches to weighting the equity models. Another NSP might come up with a very different weighting for their proposal, and on each occasion, there will be the potential for further disputes with the AER.

Table 7: JGN's Original and Revised Weightings.

Equity Model	JGN original proposal	JGN revised proposal	Other NSP?
SLCAPM	12.5%	25%	10%
Black CAPM model	25%	25%	15%
Fama-French 3 stage model	37.5%	25%	40%
Dividend Growth Model (DGM)	25%	25%	35%

Source: JGN, *Revised 2015-20 Access Arrangement*, November 2014,

The EMRF finds this approach by JGN both arbitrary and subjective. As such, it is not appropriate approach for economic regulation. In particular, the approach has resulted in JGN proposing a MRP and overall cost of equity that does not align with current market conditions as discussed previously.

4.6.4 Credit Ratings and Risk Assessment

JGN has proposed that gas distribution businesses are at higher risk than the electricity network businesses. JGN claims that the credit rating for the benchmark efficient gas distribution business should be BBB and more account should be taken of the higher risks in the overall assessment of the WACC.

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[118] As assessed by JGN's consultant, SFG Consulting.

In making this claim, JGN ignores the protections provided by the regulatory framework such as the relative assurance of revenues and cash flows over 5 years, the maintenance of the real value of the asset base, the move to a 10 year trailing average, the capacity to update annually the cost of debt, the pass through arrangements for unexpected costs and the low credit risk exposure to customers.[119]

JGN's proposal also ignores the discount rates used by its own corporate body. As cited in Table 6 above, SGSP (and its predecessor, SPI Australia), does not distinguish between its regulated gas distribution businesses and its regulated electricity and water businesses; they are all assigned the same discount rate (6.28% in 2014).

SGSP has very sophisticated owners, who would differentiate the discount rate if they saw significantly different risk, as they do for Zinfra, the commercial service provider arm of the business.

Similarly, JGN's parent company SGSP, credit rating is BBB+ (or Baa1) and stable. In a practical sense, however, the AER uses ratings based on BBB (including BBB+, BBB and BBB-) so there is little difference in the actual outcomes.

Interestingly, the EMRF notes the statements by SPI as part of its sale of 60% of its assets to the State Grid Corporation of China: "Australia has a resilient economy and a transparent regulatory and legal framework".[120]

4.6.5 JGN's proposed amendments to the cost of debt approach

The EMRF is concerned about JGN's proposed amendments to the cost of debt approach that was set out in the AER's Rate of Return Guideline, as discussed briefly below.

Annual updating of the averaging period:

> JGN has claimed this will better allow the network to match the benchmark cost of debt with its actual debt management practices.
>
> However, the EMRF considers this misstates the purpose of the

[119] SGSP states: "The Group therefore considers credit risk exposure to be minimal". See SGSP (Australia) Assets Pty Ltd, *Notes to the Financial Statements for year ended 31 March*, Note 29 (c), p 59. In the case of Jemena, its main exposures are to retailers and a small number of very large customers. Jemena is also able to obtain certain guarantees and collateral if required.

[120] See for instance, the SPI public announcement of the transaction dated 21.05.13 which can be found: http://www.zinfra.com.au/News-and-Media/May%202013/State%20Grid%20Corporation%20of%20China%20to%20invest%20in%20Singapore%20Powers%20Australian%20utility%20businesses.aspx

requirement to set the averaging period for the debt calculations at the start of the regulatory period.

It is not the purpose of the procedure to minimize the risk of any individual network. It is designed to provide a certainty in the process for both network investors and consumers.

Annual updating of the averaging period will allow networks to cherry pick the best outcome irrespective of their actual debt strategy or even an efficient debt strategy.

Moreover, the AER Guideline allows considerable flexibility in the period of the averaging up to a maximum of one year. If a network is concerned about picking a period that gives a 'poor" result in subsequent year, it has the flexibility to extend the proposed averaging period and minimize the intra-year volatility risk.

The EMRF supports the AER in not adopting this approach.

Adopt the AER's transition approach for the risk free rate but apply the 10-year trailing average of the debt risk premium from 2015 (the "hybrid" approach to transition).

JGN is concerned that the DRP has dropped by over 70 basis points between June 2014 and February 2015. The hybrid approach would protect JGN during the transition period.

The EMRF notes that the DRP over the last few months has been sitting between 2.3 and 2.5. From a long-term perspective this DRP is not unreasonable particularly for a low risk regulated entity with a guaranteed indexed asset base and stable cash flows. Investors looking for long-term returns keenly seek such investments. International data supports regulators making decisions such as this.

As noted above, APA raised considerable funds recently, and with the investors having full knowledge of the new regulatory framework.

In addition, the hybrid approach disadvantages consumers, particularly as the move to a 10-year DRP for a BBB+/BBB company means that the DRP will include a heavy weighting on the high debt premiums seen during the GFC. It is unlikely that this is representative of the portfolio cost of debt of JGN, or any other well run network.

The EMRF recommends that the AER does not adopt this approach. In the event the AER considers this, the EMRF requests that there is opportunity for more public analysis and communication on the possible impacts.

4.7 Conclusions on the AER's draft decision on the rate of return

While the EMRF continues to have some concern with the AER's Rate of Return Guideline, it also recognises that the Guideline was developed after extensive consultation with a range of stakeholders. The EMRF also notes that the AER has, over the course of this consultation, carefully considered all the relevant estimation methods and other material that was put before it.

The EMRF is therefore firmly of the view that the AER should apply its Guideline approach, recognising that this approach is still a conservative assessment but one that provides transparency and some certainty and consistency in its outcomes.

On the other hand, it is the EMRF's view that JGN's revised proposal overestimates the cost of equity and this is partly due to JGN reliance on "averaging" across four different models and providing subjective and arbitrary weightings on these models.

Overall therefore, the EMRF considers that the AER has appropriately had regard to all the alternative financial models, estimation methods etc put to them. The AER has exercised its judgment to decide which of the approaches is best suited to achieving the allowed rate of return objective.

On the other hand, JGN has failed to demonstrate that:

- The AER's rate of return guideline as applied in the draft decision does not meet the requirements of the NGR;
- In the alternate, JGN"s proposed WACC is a preferable decision that better meets the long-term interests of consumers as required by the NGO;
- The AER's allowed rate of return is not sufficient for JGN to recover its costs of capital and invest in the reliability and safety of its networks.

The EMRF considers that JGN's suggested amendments to the AER's approach to the cost of debt and the transition to the new cost of debt are not in the long-term interests of consumers. The revised averaging approach exposes consumers to the possibility of annual "cherry picking" of the relevant dates, while the amended transition exposes consumers to the high debt premiums that were seen during the GFC periods, and for which consumers have already paid.

5 Forecasts of Gas Demand & Customer Numbers.

The gas demand forecasts and customer growth forecasts are both two key inputs into the capex and opex forecasts and the demand forecast is a core element for calculating reference prices from the AER's overall revenue allowance.

Under an average maximum price form of control the forecasting of both total demand and demand by individual tariff segments becomes even more important if consumers are not to pay more in total than expected by the AER's revenue allowances.

The EMRF is most concerned that networks in general appear to have been able to consistently achieve revenues above their allowances even as demand declines below forecast levels.

One way this consistent bias can occur is if the AER's allowed demand forecast is too low so that average prices are higher than needed. However, if demand exceeds the forecast, then the network is likely to recover more revenue, and under a maximum average price cap, the network will keep this revenue.

Thus there is a strong economic driver by JGN to understate forecasts of volume and overstate forecasts of customer numbers (as this drives higher capex)

Another method to extract more than allowed revenues is to structure tariffs in such a way, that small changes in actual usage compared to forecast in particular segments of the customer mix (and tariffs) can lead to large changes in revenue outcomes.

The EMRF understands the AER has addressed the issues that have emerged of systematic over recovery of revenue under the maximum price cap by moving to a revenue control form for all electricity distribution networks. However, the maximum average price cap form of control is continued for the gas distribution networks.

It is for this reason that the EMRF believes the AER should consider the evidence carefully and decide on the most reasonable forecast of gas volumes and peak demand given the expected developments in the gas market over the regulatory period. In making such assessments, the AER should also recognise that even where actual volumes are less than forecast, the loss of revenue seen has not been proportionate. This would indicate that there is a bias in outcomes, such that the risk to a network of less than forecast volume is less than the benefit to the networks of greater than forecast volumes.

In particular, the AER should look very carefully at forecasts that combine a significant drop in volumes with a larger increase in consumer numbers as set out in JGN's proposal because of the potential distortion of the maximum price cap control as described above.

A further important consideration for the AER is to ensure that there is consistency between the various forecast components.

For example, if the AER's Final Decision is similar to its Draft Decision, then it can be expected that overall gas prices will not increase and may even decline (as network costs account for at least 50% of the total retail cost for small consumers of gas). The gas forecasts must therefore include a response to a retail price decrease based on the elasticities reported by both Core Energy and DAE.

5.1 JGN's proposed forecast of gas volumes and peak demand

JGN has relied on Core Energy Group Pty Ltd (Core Energy) for its forecasts of demand and customer numbers.[121] Core has prepared separate forecasts of average consumption per customer for the following segments:

- Tariff V – Residential (less than 10 terajoules (TJ) per annum (p.a.)
- Tariff V – Small business (less than 10TJ p.a.)
- Tariff V – Industrial & commercial (I&C) customers (less than 10TJ p.a.)
- Tariff D – I& C customers consuming more than 10 Terajoules (TJ) per annum

For Tariff V customers, Core forecasts consumption, while for tariff D customers, Core forecasts both consumption and Maximum Daily Quantity (MDQ).

Historical gas consumption is adjusted for variations in weather, as gas demand for V tariff customers is very weather dependent. JGN/Core have

[121] Jemena Gas Networks (NSW) Ltd Access Arrangement, Appendix 3.1 – Demand forecasting report – response to draft decision, February 2015. A report by the Core Energy Group [Core Energy, *Demand forecasting report*, Feb 2015].

applied a standard weather correction measure to the gas consumption data.

Overall (Tariff V and Tariff D), JGN/Core Energy's forecast includes a decline in gas consumption of some 13% from 2014 to 2020.[122] The decline comes from both Tariff V and Tariff D customers. While customer numbers generally grow by about 2% p.a. there is a sharp drop in average consumption per customers in the order of 2% to 4% p.a.

This is a significant change in NSW gas use, and given the potential impacts discussed above of declining consumption and rising consumer numbers, it is important that the AER revisit its critical assessment of the forecast.

5.1.1 Tariff V customers' consumption

For tariff V customers, Core Energy uses an "historical trend" approach, with the various drivers of consumption reflected in the forecast outputs rather than explicitly identified (e.g. by being represented as specific variable in the regression analysis).

If there are "step changes" in these drivers in the forecast period, they are captured by "out-of-trend" adjustments.[123] Of these potential out of trend drivers, Core identified the following as important given the expected market conditions over the AA2 period:

- (Retail) Price elasticity – both own price and cross price elasticity[124]

Core did not find a statistical relationship between economic measures such as gross household disposable income or gross state product (GSP) and average consumption per connection.[125] Notably, Core had found such a relationship in Victorian between the economic variables and gas consumption.[126]

5.1.2 Tariff V customer connections

Core Energy used a bottom up forecasting that involved:[127]

- Assessment of the historical trends in new connections and rate of disconnections;

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[122] Estimated from Core Energy, *Demand forecasting report*, Feb 2015, Tables 4.2 to 4.8.
[123] Jemena, *2015-20 Access Arrangement, response to the AER draft decision & revised proposal*, February, 2015, pp 9-10 (@ 98).
[124] Ibid, p 10.(@94-100)
[125] Ibid, p 11.(@ 102)
[126] Ibid, (@105)
[127] ibid, p 12 (@ 107 – 108)

- Analysis of the historical trend in the dwelling mix for new connections, most particularly the mix between new medium/high density dwellings (with lower than average gas consumption) and housing estates; and

- Adjusting connection forecasts for factors not present in the historical trend including forecasts of relative prices of gas and electricity.

Core Energy's updated forecasts are summarized in Table 7 below.

Table 7: Core Energy updated forecasts for Tariff V customers

	Average GJ per connection			**Customer Connection No.**		
	2014 #	2020 #	Change %	2014 #	2020 #	Change %
Residential	20.8	16.85	- 19%	1,172,432	1,355,105	+15.6%
Small business	246.36	161.73	-34.3%	22,125	26,413	+19.4%
I & C < 10 TJ/pa	455.88	369.15	-19%	16,827	19,080	+13.4%

Source: *Core Energy, Demand Forecasting Report*, Appendix 3-1, Feb 2015. Adapted from Table 4.5 and 4.6, p 33.

Core Energy's analysis summarized above, demonstrates the following outcomes:

- A very significant decline of around more 3% per annum in average consumption per connection, and

- A growth in customer connections at around 2-3% per annum; and

- A growth in aggregate V tariff demand of around 6.8% (average use * customer number).

Core Energy notes that the total V tariff consumption forecast has increased by around 1% p.a. since its original analysis for JGN. However, this increase is driven by a relatively larger increase in customer numbers following the updated forecast of dwelling completions and residential connections. The average consumption per customer is lower in the revised forecast.[128] This is likely to be the result of a forecast of higher gas prices.

[128] Based on comparison of Tables: 4.1 and 4.5; 4.2 and 4.6; and 4.3 and 4.7, Core Energy report, pp 32 – 33.

The overarching question is, however, whether such a decline in average consumption per customer is feasible over five years, given the relative "stickiness" of gas equipment is feasible.

The reduction in average consumption per small business customer is particularly striking in the Core Energy Analysis.

In addition, it brings into question the benefit of JGN promoting gas in new estates, as it is difficult to envisage what the average price per household/premise would be if JGN was to recover its long-run costs to supply to these customers.

5.1.3 Tariff D customer forecasts of consumption

The key variables for forecasting tariff D costs and revenues are the Annual Contract Quantity (ACQ, equivalent to annual consumption), the Maximum Daily Quantity (MDQ) and the Contract Demand (CD).

Table 8 below summarises Core's forecasts of consumption. Again there is steep decline in annual quantity of consumption of around 17% from 2014. The decline in MDQ from 2014 is about the 21% and CD by about 23%.

Table 8: Core Energy forecast of D Tariff consumption

Tariff D	2014	2015	2016	2017	2018	2019	2020
ACQ	55,156,511	48,622,030	48,465,714	47,627,204	46,947,725	46,234,667	45,637,630
MDQ	337,070	278,396	276,777	272,291	269,306	266,932	266,932
CD	348,512	278,396	276,777	272,291	269,306	266,932	266,932

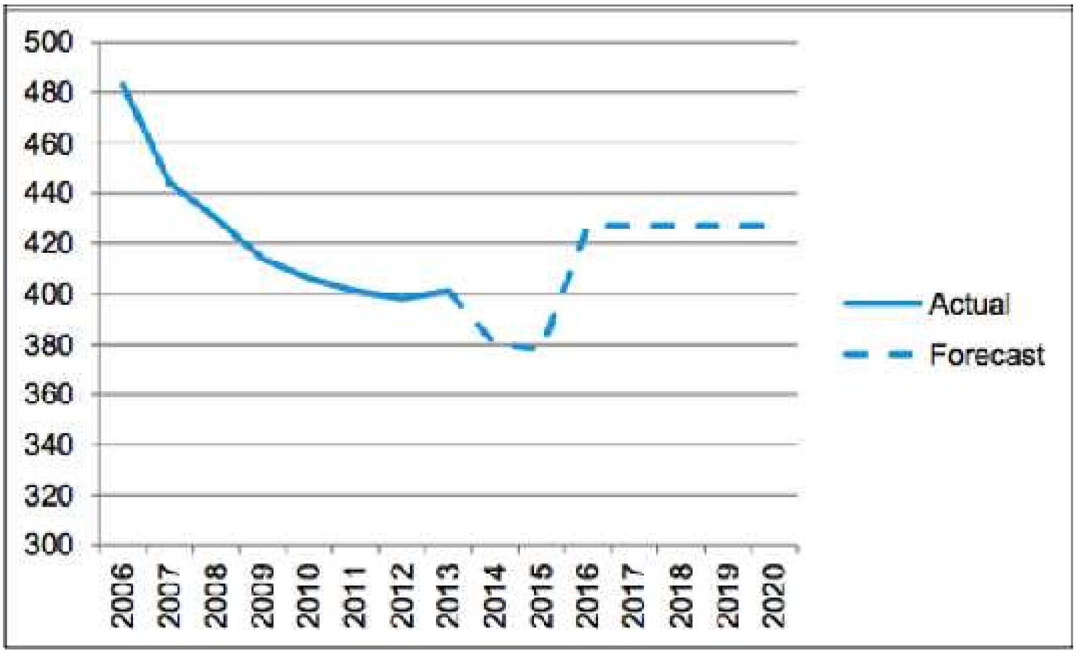
Source: *Core Energy, Demand Forecasting Report*, Appendix 3-1, Feb 2015, Table 4.8, p 34

5.1.4: Tariff D customer connection forecasts

Figure 12 below illustrates both the historical movements in Tariff D connections and Core Energy's forecast (as provided by DAE). Tariff D customers are expected to decline to 2015, but then increase in subsequent years.

Part of this increase may be tariff reclassification, however, there is expectation of some improvement in the NSW economy.

Figure 12: Total Tariff D connections – Core Energy forecast



Source: Deloitte, *Gas demand forecast, Jemena*, Nov 2014, Chart 3.3, p 19

5.2 The AER's Assessment of JGN's consumption forecast

The AER, on advice from DAE, accepted JGN's forecast of Tariff D customer numbers, ACQ, MDQ and CD.

However, the AER has not accepted JGN's forecasts of gas demand and peak demand. The AER has relied on the assessments by Deloitte Access Economics (DAE).[129]

5.2.1 AER's forecast of Tariff V Gas Consumption

There was general agreement with Core Energy's forecast of Tariff V gas customer numbers.

The AER did not, however, accept JGN/Core Energy's forecast of average consumption per customer for Tariff V customers. Under advice from DAE, the AER proposed a higher average consumption and therefore a larger increase in overall gas usage.

[129] Deloitte Access Economics, *Australian Energy Regulator Gas demand forecast for Jemena's NSW network*, 24 November 2014. [Deloitte, *Gas demand forecast for Jemena*, Nov 2014]

The main (but by no means only) source of difference between Core Energy's forecasts and DAE's appears to be in the type of time series analysis applied to the historical data and its subsequent extrapolation to the forecast period.

For example, Core Energy used a time series analysis approach with adjustments for the impact of the forecast retail gas price changes made externally to the model. In contrast, DAE applied a structural model of consumption with prices and economic conditions (e.g. gross state product (GSP) and State Final Demand (SFD) included in the model itself, rather than external adjustment.[130]

Both DAE's and Core Energy's modeling found that gas usage had some sensitivity to price changes and given the extent of the price forecasts in NSW this will have an effect on average usage per customer as both forecasters found (albeit in different ways). Both DAE and Core Energy reported own-price elasticity of around -0.3 – 0.35. However, they did not agree on the relevance and size of cross-price elasticity over the regulatory period.

More controversial, perhaps, is DAE's inclusion of the economic growth component (GSP, SFP) that acts to modify the impact of price increases on gas demand. DAE econometric model finds GSP a significant parameter in its analysis.[131] Therefore, the EMRF considers it reasonable to include it in DAE's outputs (in fact it would be unreasonable to exclude it, if it was found to be statistically significant).

In contrast, Core's forecasting model did not test GSP impacts within its time-series model, although separate assessment did not find the economic variables statistically significant. Core Energy also reviewed the statistical analysis of DAE's study and state that they found limited evidence of a GSP/FSP effect.[132]

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[130] For example, see Deloitte, *Gas demand forecast for Jemena*, Nov 2014, p 11 -12.
[131] See Ibid, Table 4.2 & 4.3 (residential and I&C respectively). The GSP coefficient (lagged) was significant for residential demand, but not for I & C. For small business, the model could not identify significant explanatory variables (such as GSP or price) in the structural model because the downward trend was larger than the effects of the variables. As a result, Deloitte accepted Core's forecast approach, although based the analysis from 2008 to 2013 rather than 2002 to 2013 (i.e. Deloitte amended Core's downward trend in small business usage of -3.2% pa to -2.5% pa). JGN appears to regard this is an inconsistency, however EMRF considers it is a practical solution given the modeling issues for that market segment. It does not obviate the use of a structural model for residential and I&C market segments of the Tariff V customers.
[132] See Core Energy, *Demand forecasting report*, Feb 2015, Attachment 2, pp 42 – 43.

5.2.2: Summary of differences in the DAE and Core Energy forecasts

A summary of the differences in outcomes from the different forecasting approaches described above.

- DAE agrees with Core Energy's forecast of overall residential dwellings growth, and gas penetration in new estates;
- DAE does not agree with Core's allocation of new dwelling construction between new estate and multi-unit (medium density) dwellings with DAE proposing a higher proportion of multi-unit dwellings;
- DAE and Core agree that there is likely to be a significant reduction in electricity to gas conversions, and while DAE is concerned with the lack of data to model this, it accepts Core's forecast;
- DAE does not agree with Core's proposed level of disconnections stating that there is a lack of data to support increases in this area;
- DAE considers that Core Energy has overstated the growth in non-residential tariff V connections as Core' Energy's approach implies a doubling of small business connections between 2012/13 and 2019/20;
- DAE agrees with Core Energy that average consumption per connection will decline, but does not agree with the rate of decline. DAE cites, for instance, the forecast recovery in the NSW economy that Core has not addressed.
- DAE and Core Energy agree with the proposal of an own-price elasticity coefficient in the order of -0.30 to -0.35 (Core) and 0.36-0.45 (DAE). However, DAE does not agree with a cross price elasticity of -0.1. DAE has proposed a figure of -0.05, although remains concerned at the lack of empirical evidence for this.[133]

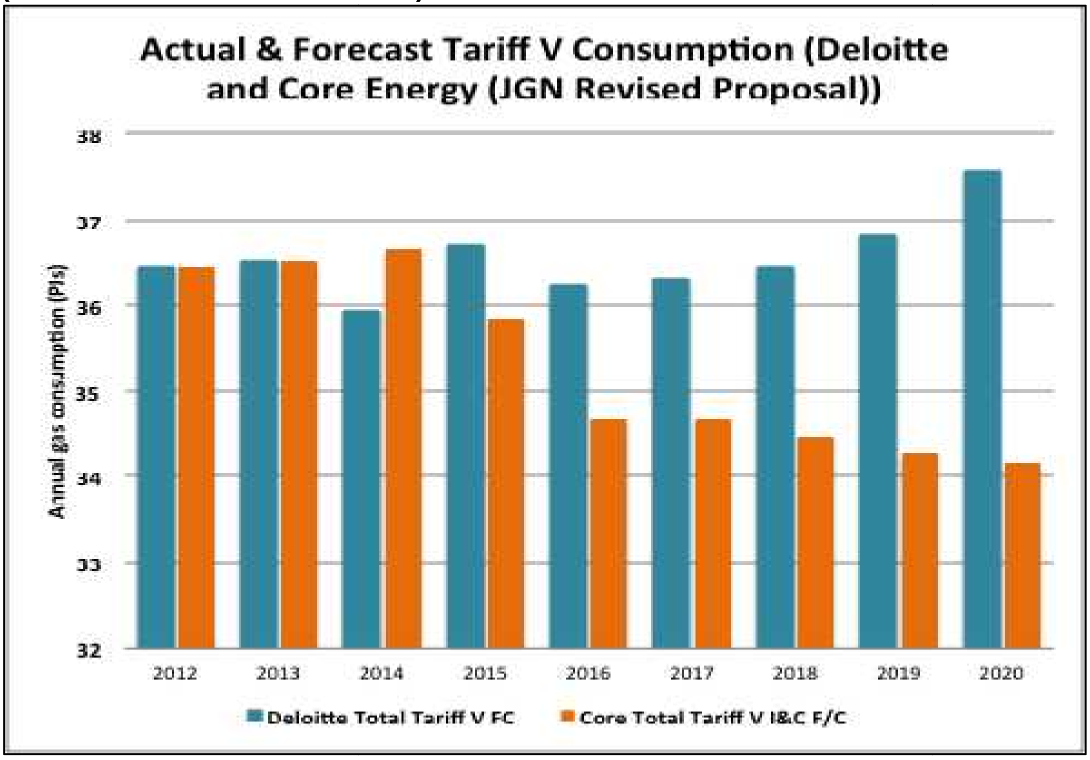
The overall effect of these differences is significant. The total difference between the two forecasts from 2015-16 to 2019-20 is nearly 11 petajoules (11 million gigajoules), even following Core/JGN's new forecast in JGN's revised proposal that increases gas usage across the next period by around 1%.

[133] For example, see discussion on elasticity coefficients in ibid, pp 28-29.

JGN states that the difference in the Tariff V forecast will result in a $90 million shortfall in revenue if JGN's revised forecast of gas usage (rather than DAE forecast) eventuates in practice.[134]

On the other hand, EMRF must assume that if the AER accepts JGN's/Core's forecast and the DAE forecast is more accurate, then consumers will pay JGN an excess of $90 million; noting that in the past, consumers have been on the "wrong" side of this risk on a regular basis and that networks have the ability to manage a reduction in consumption more than consumers have.

Figure 13: Actual & forecast Tariff V annual consumption (2012 -2014 based on actual data)



Source: EMRF analysis, Deloitte, *Gas demand forecast for Jemena*, Tables 5-1-5-4, pp 32-33). The Core forecast has been updated as per JGN's revised proposal, Table 3-6, p 41.

Figure 14 illustrates the differences in the two components of Tariff V, the residential and non-residential segments, between the forecasts by DAE and Core.

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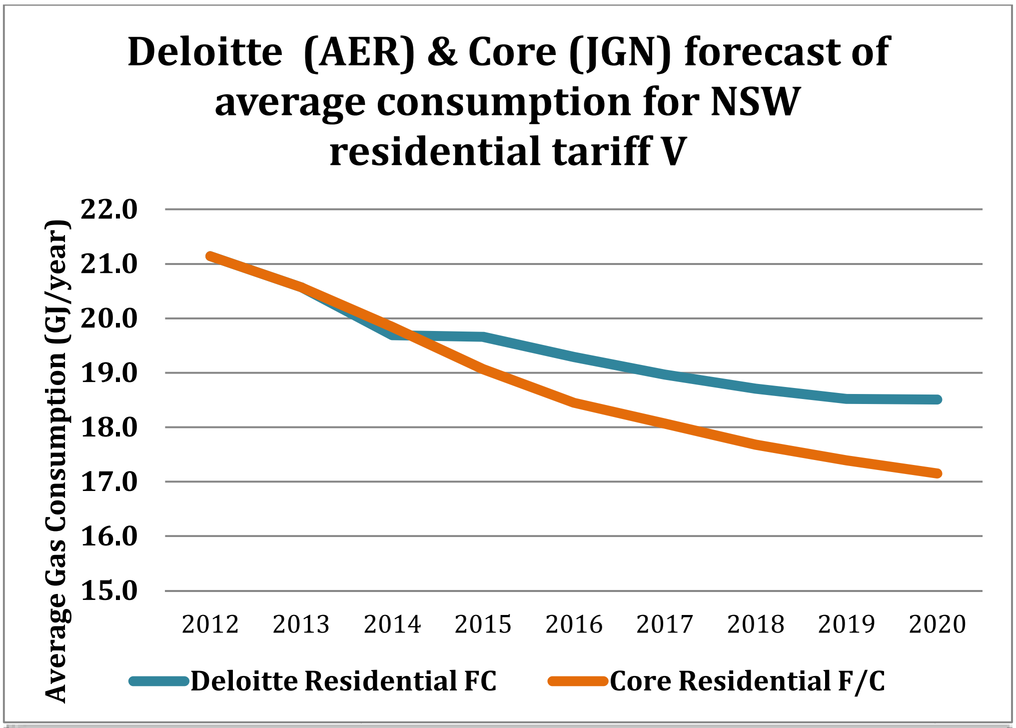
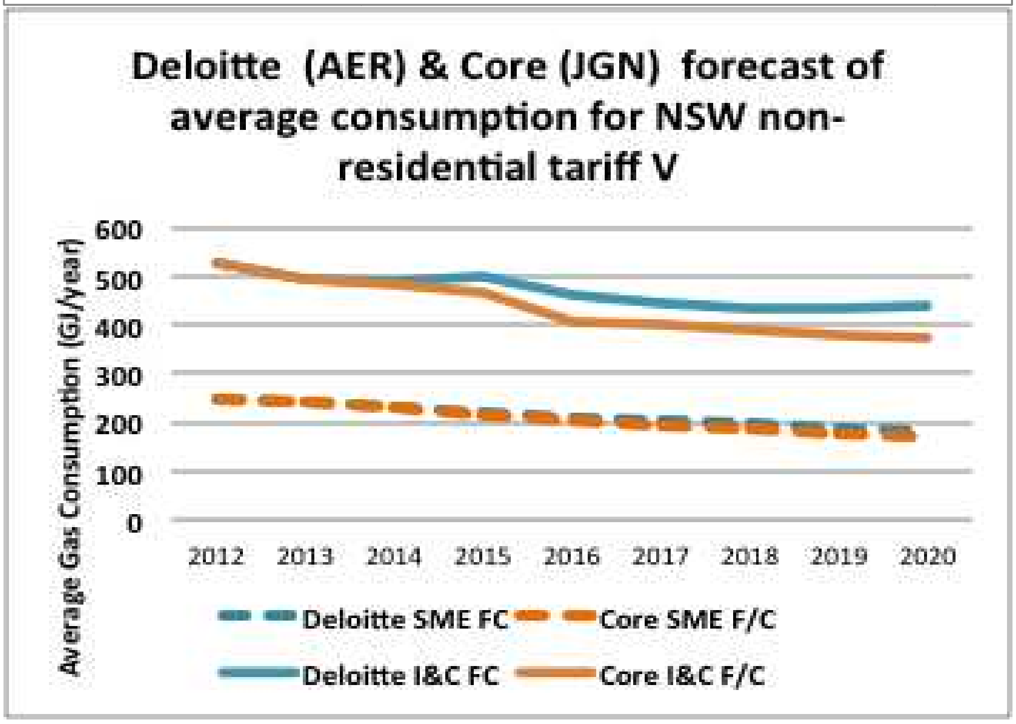
[134] See for example, Jemena, *2015 Access Arrangement, response to the AER draft decision*, February, 2015, p 15. The difference arises because of the operation of the maximum average price cap form of control.

Figure 14: Forecasts of average consumption per customer for Tariff V customers in NSW





EMRF analysis, Deloitte, *Gas demand forecast for Jemena*, Tables 5-1-5-4, pp 32

Given the importance of the forecast trends in demand to the final network prices that consumers "see", the EMRF has also considered alternative forecasts for NSW gas demand, including the forecasts provided by the

Australian Energy Market Operator (AEMO). AEMO"s NSW gas forecasts are described below.

It is recognised that the forecasts will differ in terms of quantum because of the different approaches to measuring the gas volumes and different classification of customers. Nevertheless, the AEMO forecast is important in terms of the forecast trends in gas demand.

5.3 AEMO's National Gas forecasts (December 2014)

In December 2014 (after the publication of the AER's draft decision), AEMO published an update of its short and long term gas forecasts for Tariff V and Tariff D customers.

AEMO has developed considerable expertise in electricity demand forecasting and has been responsible for forecasting Victorian system gas demand for over a decade.

AEMO has also produced the Gas Statement of Opportunities (GSOO) for a number of years. However, AEMO notes that until 2014, it has relied on external forecast providers for the inputs to the GSOO.

Over 2014, and in consultation with the industry and ACIL Allen, AEMO developed its own in-house gas forecasting capabilities. In December 2014, AEMO published a national gas forecasting report[135] that provided regional forecasts for Queensland, NSW, Victoria, South Australia and Tasmania. Separate forecasts are provided for low, medium and high growth scenarios. [136]

These forecasts were not available at the time of the AER's Draft Decision in November 2014.

AEMO's key findings for NSW gas demand for 2013-19 were as follows for the medium growth scenario [range high growth to low growth]:[137]

- Total gas consumption is forecast to decrease at an average annual rate of 1.8%;

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[135] AEMO, *National Gas Forecasting Report for the Eastern and South-Eastern Australian Gas Region*, December, 2014. AEMO's medium growth forecast includes the assumption of a medium economic growth forecast and high "consumer engagement" (this refers to consumers more proactively exercising choice of energy sources and usage patterns. (refer to AEMO's report, Table 4, p 11 for details).
[136] Ibid, Table 4.2.4, p 29 provides a description of the different scenarios and the associated forecasts of gas usage and average annual growth for "Residential & Commercial", "Industrial" and "gas powered generation".
[137] Ibid, p 25.

- Residential and commercial consumption is forecast to increase at an average rate of 1.4%, driven by new gas connections offset in part by the continued **decline in average use per connection continuing**; [EMRF emphasis]; [Range 1.9% to 0.4%]

- Industrial gas consumption is forecast to decrease at an average annual rate of 2.6%, driven by the closure of industrial plants [range +0.7% to 5.4%]; and

- Gas power generation (GPG) consumption is forecast to decline at an average annual rate of 6.2% driven by rising gas prices that reduce the competitiveness of GPG plants in the National Electricity Market (NEM) [range -6.4% to -8.3%]

Figure 15 below illustrates the change in AEMO's forecast of gas demand between 2013 and 2019 for "residential and commercial" (equivalent to Tariff V), "industrial" (Tariff D) and gas powered generation (GPG).

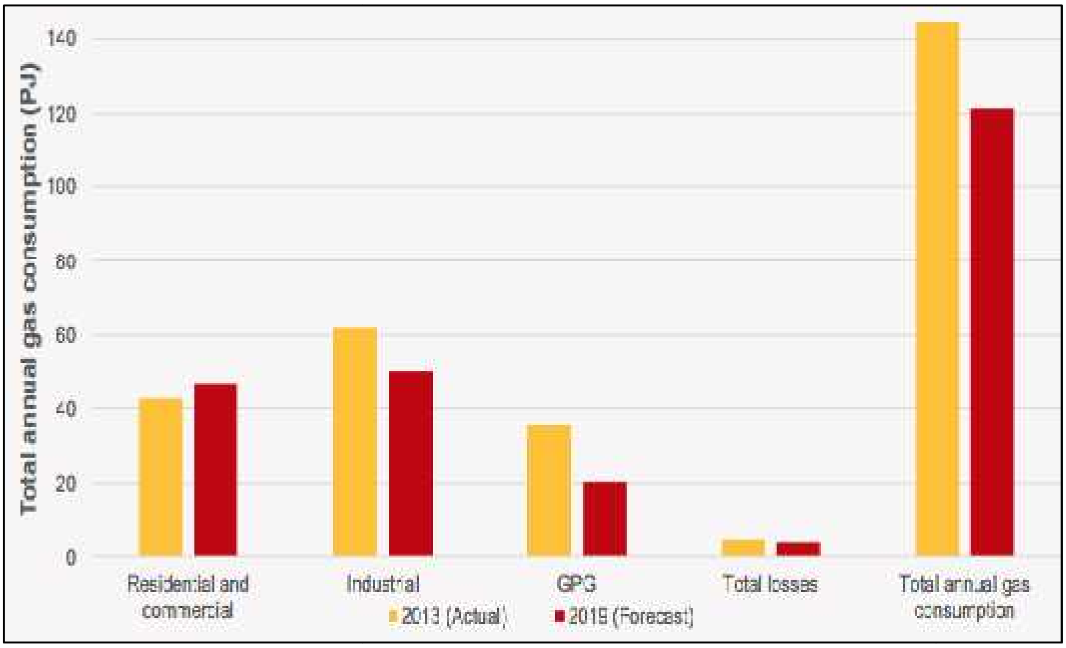
AEMO adopted an econometric trend modeling approach to Tariff V forecasts of average consumption and surveys and direct discussions with large industrial customers for assessing the industrial usage. The overall approach is similar to both Core Energy and DAE, although the model specifications differ at a more detailed level.[138]

AEMO's independent forecast concluded that while average consumption was declining due to rising gas retail prices and energy efficiency savings, overall consumption grew as a result of increased connections to the network: [139]

> *On a weather corrected basis, [historical] residential and commercial consumption increased at an annual average of 1.1%. This reflects an increase of connections to the gas network. Average use per connection declined over the period, linked to rising retail gas prices and savings from federal energy efficiency programs.*

[138] For a more detailed description of AEMO's approach to forecasting Tariff V consumers, see AEMO, *2014 National Gas Forecasting Information Paper, Final*, December 2014, pp 8 – 18.
[139] Ibid, p 27.

Figure 15: Comparison of 2013 (actual) and 2019 (forecast) annual gas consumption (medium growth scenario)



Source: AEMO, *National Gas Forecasting Report*, Figure 10, p 25. "Residential and commercial category" refers to all Tariff V customers, "Industrial" refers to the total Tariff D customers (as at 2013) – see AEMO report, p 11.

At this high level, AEMO"s forecast is more aligned with the AER/DAE forecast than JGN/Core Energy forecast, after removing the impact of gas fired generation on total gas sales for NSW.

That is, AEMO finds a small but significant *increase i*n total Tariff V ("residential and commercial") usage and a larger decline in Tariff D (industrial) usage.[140] This contrasts with the Core Energy's forecast of significant *decrease* (in the order of 2% to 4% per annum) in total gas usage for V tariff customers.

5.4 EMRF response to the AER's Draft Decision & JGN's Revised Proposal

5.4.1 Is Core Energy's forecast of 2% - 3% pa decline in average consumption a reasonable forecast?

Generally, the EMRF considers that output of Core Energy's forecast of sustained 2% - 3% p.a. reductions in average consumption per consumer

[140] There will be a slight difference in the total usage for each tariff segment between AEMO and DAE and Core, as AEMO used meter data while Core used billing data. AEMO reports that the "main NSW distributor" did not provide billing data to AEMO. See AEMO, *Forecasting Methodology Information Paper*, *National Gas Forecasting Report*, December 2014, p 8.

(V tariff) seems very high, particularly given the relatively long life of gas appliances.

For instance, the EMRF has referred to AEMO's NSW gas demand forecast as an alternative, albeit high level, forecast from an independent and respected source with a transparent scenario based approach.

The EMRF finds the DAE forecast of average consumption per connection more credible as it is closer to the AEMO's forecasts for Tariff V customers.

Moreover, if it was true that average usage was declining at this rate, then it implies that the 30,000 p.a. new connections forecast for 2015-20, would have very low average consumption.[141] This in turn raises questions about the cost- benefit of Jemena's marketing strategy and related capex expansion plans.

5.4.2 The interaction of the network prices, retail prices and price elasticities average consumption per connection

In addition, the EMRF is concerned about the internal consistency of the JGN/Core Energy forecast.

It would seem, for instance, that the declining average usage is (largely) a function of the application of price elasticities that are applied externally to the trend forecast model used by Core Energy.

The impact of these elasticities (both own-price and cross-price) will clearly depend on the forecast of *retail gas prices* over the regulatory period. There is limited evidence available regarding the expected forecast of retail gas prices.

However, the EMRF has reviewed IPART's final report on regulated gas retail pricing the 2014-15 to 2015-16, covering residential and small business customers (less than 1TJ p.a.) and found some anomalies in Core Energy's approach.[142]

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[141] With over 1.1 million V tariff customers, and very low forecast of gas increases in existing gas connected homes, the additional 30,000 new customers must have a consumption much lower than the average.

[142] Independent Pricing and Regulatory Tribunal, *Changes in regulated retail gas prices from 1 July 2014, Gas – Final Report*, June 2014. [IPART, *Final Report, Changes in regulated retail gas prices, June 2014*]
http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Changes_in_regulated_gas_retail_prices_from_1_July_2014/10_Jun_2014_-_Final_Report/Final_Report_-_Changes_in_regulated_retail_gas_prices_from_1_July_2014_-_June_2014

IPART's assessment of the regulated gas price included forecasts of increased gas commodity costs (due to LNG export) and increases in nominal network costs for 2014-2015 and for 2015-2016.

IPART approved increases in gas retail prices (for small customers on standard contracts[143]) as set out in Table 9 below, assuming removal of the carbon tax from July 2014, and based on the expected network costs for 2014-15 and a forecast network cost for 2015-16 (using the AER's Guidelines)

As Table 9 demonstrates, in assessing the regulated gas retail prices, **I**PART is forecasting a small nominal increase in the network charges (1.1%) for **2015-16** made up of a CPI increase in network charges that is slightly offset by the assumed removal of the carbon tax in 2015-2016.

However, in its 2015-20 regulator proposal, JGN is forecasting a reduction in nominal prices for Tariff V customers of over 5% for 2015-16 and cumulative reductions over the five-year regulatory period for residential customers of around 40%.[144] This is very different to IPART's assumptions of network prices when reviewing the regulated retail price.

Table 9 also provides an estimation by EMRF of how Jemena's tariff proposal for 2015-16 would impact on the overall regulated retail gas prices in 2015-16, given IPART's assumptions for the retail and wholesale cost components.

Adopting the AER's draft decision parameters would result in even larger network revenue reductions, at least some of which are likely to be allocated to Tariff V consumers with network price reductions greater than -5%.

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[143] Small customers are residential and small business customers less than 1TJ p.a. The standard contracts are the regulated contract prices, but most gas customers are on market contracts generally less than the regulated prices.

[144] Jemena, *2015-20 Access Arrangement Revised Proposal*, February 2015, Table 10-5, p 113.

Table 9: IPART's approved increases in standard gas retail tariffs, Jemena/AGL area, $ nominal - contribution to price increase by cost component

Retail Cost component	**% of total costs 2013-14**	**% of Total Change 2014-15**	**% of Total Change 2015-16**	**JGN tariff changes 2015-16**
Retail & wholesale (1)	46%	6.0%	4.7%	4.7%
Distribution network (2)	48%	5.7%	1.1%	≈ −5%
Carbon (3)	6%	0.0%	0.0%	0.0%
Total Bill Change, $ nom		**11.7%**	**5.8%**	≈ **-1.7%%**

Source: IPART, *Fact Sheet, Regulated retail gas prices from 1 July 2014 to 30, June 2016*.[145] Figure 1, page 3 adjusted (by the EMRF) for removal of carbon in wholesale costs.
Notes:

(1): Wholesale costs include transmission costs. The total gas price including transmission allowed by IPART for 2015-16 is in the range of $6.40 to $9.00/GJ, based on reports by Jacobs SKM, and ACIL Tasman (now ACIL Allen). See IPART's Final Report.[146]
(2): Distribution increases for 2014-15 include a small component of carbon cost that was included in the network price. This is removed in the 2015-16 forecast.
(3) Figure 1 in the fact sheet includes a carbon price for 2014-15. However, IPART provides a separate estimate of the total retail price increase if the carbon price was removed at the start of 2014-15. The Table 9 is adjusted to account for the removal of the carbon price in July 2014.

The analysis above suggests that that overall *regulated retail prices* are likely to change at a much lower rate (and even decline) than suggested by the Core Energy reductions in average usage. Certainly, the increases in gas retail prices will be less than those experienced by gas consumers over the last few years.
147

Moreover, IPART accepted relatively "bullish" gas prices in their assessment of the regulated prices. IPART took the view that if gas prices did not increase as forecast (which is a reasonable expectation given the more recent changes in international oil and gas prices), retail competition would reduce market prices well below the regulated price.

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[145] See http://www.ipart.nsw.gov.au/Home/Industries/Gas/Reviews/Retail_Pricing/Changes_in_regulated_gas_retail_prices_from_1_July_2014/10_Jun_2014_-_Fact_Sheet_-_Final_Report/Fact_Sheet_-_Regulated_retail_gas_prices_from_1_July_2014_to_30_June_2016
[146] IPART, *Final Report, Changes in regulated retail gas prices*, June 2014, Table 3.1, p 25.
[147] IPART states that the gas retail price has increased by around 40% in real dollar terms between 200607 and 2013-15. See ibid, p 36.

IPART has forecast that some 95% of NSW gas consumers will be on market tariffs by 2020.[148] Currently, most retailers are offering discounts of 10% on the standard regulated gas tariffs.[149]

Based on all these factors, EMRF would like to see more clarity about how Core Energy derived the retail gas prices it uses in its modeling as well ah how it applied its "exogenous" variables such as own-price and cross price elasticity to this forecast retail gas price for Tariff V consumers.

5.4.3 Conclusions on EMRF's view of JGN's forecasts

Overall, given the importance of the AER's final decision on gas volumes and customer numbers to the capex and opex forecasts and the development of the gas network tariffs, it is appropriate for the AER to give more consideration to other independent forecasts.

For instance, the EMRF considers that the NSW gas volume forecasts by AEMO provide a very useful starting point to assess Core Energy's forecast from a "top-down perspective.

The EMRF also requests the AER to consider more closely the assumptions about future gas retail prices by Core Energy and the application of price elasticities to the retail price.

[148] Ibid, Figure B3, p 53.
[149] Based on offers published on the AER website "energymadeeasy". http://www.energymadeeasy.gov.au

6 Pricing Methodology

The EMRF repeats the comments made in earlier sections, especially section 2 where it highlights that the capex proposals by JGN are focused on the tariff V customers and that there are significant benefits from the lower cost of capital.

Despite these two very large impacts on the overall revenue allowance, the pricing proposal by JGN leads to an increase in tariffs for tariff D customers offset by large reductions for tariff V customers. As the EMRF noted in its response to the JGN initial proposal, the EMRF considers that tariffs should be constructed in a cost reflective manner, where each customers pays its fair share of the costs of the infrastructure each uses.

In neither the AER draft decision nor in the JGN revised proposal, is there any attempt to ensure that prices are cost reflective. This is just as a great concern to the EMRF as it would be for smaller users to ensure there is no cross subsidization between customer classes.

6.1 Regulatory framework

Consumers see network pricing as an essential element in the AER's regulatory processes as network pricing has the more immediate relevance to their bills

Network pricing also has an important role in signaling to consumers the efficient utilization of the networks. This is a key assumption, for instance, in the AEMC's Power of Choice reform program.

The NGR provides only a broad set of requirements for guiding gas distribution tariffs, as set out in r. 93 and r. 94 of the NGR. R. 93 sets out how revenue is to be allocated between reference and other service on the basis of the underlying cost allocations.

R. 94 states that for each tariff class, the revenue from that tariff class should lie on or between:[150]

(a) an upper bound representing the stand alone cost of providing the reference services to that class of customers; and

(b) a lower bound representing the avoidable cost of not providing the reference services to those customers.

In addition, where a tariff consists of two or more charging parameters, each charging parameters:[151]

[150]See NGR, r. 94 (3).

(a) must take account the long run marginal cost of providing that element of the service; and

(b) must be determined having regard to transaction costs and whether customers belonging to that class are able or likely to respond

(c) to price signals.

The AER's discretion under r. 94 is limited. Providing the AER establishes that JGN has complied with these broad requirements, the AER does not have the discretion to replace JGN's proposed tariff structure with a preferable decision that more closely reflects the actual costs of service and consumers long-term interests.

The NGR, therefore, does not include the extensive reforms to the network tariff requirements that are set out in the AEMC's recent amendments to the NER.

However, the AER does have the power to assess whether reference prices that are established are designed to achieve and outcome that it not in the long term interests of consumers. For example, if JGN were to set excessively low prices that resulted in an increase in new connections and associated augmentation of the network that were the result of cross subsidization that could be unwound at a later date, then the decision to reduce prices would not be efficient in the long term.

To overcome this potential anomaly, the AER has to be assured that the prices are as close to cost reflective as possible rather than being set close to the avoided cost just to drive an increase in capex. Inefficient price setting in the short term can result in inefficient utilisation of the network, causing consumers harm in the long term.

It is with this in mind that the EMRF has consistently sought for prices to be cost reflective rather than lie within the very wide bounds of avoided cost and stand alone cost.

6.2 JGN's Proposal and the AER's draft decision

6.2.1 JGN's Revised Tariff Planning Process

JGN has undertaken some important reforms to gas network tariffs for the next period by simplifying tariffs and charges, consolidating fixed charges and removing redundant tariffs. Such actions support the further

[151] See NRR, r. 94 (4).

development of retail competition and facilitate users such as the EMRF members understanding their gas network tariff arrangements.

JGN has also committed to producing a Tariff Structure Statement (TSS), consulting with its Customer Council, retailers and residential and business customers. JGN also plans to publish its annual network tariffs by 15 March each year, giving longer notice to retailers and others of actual prices.

The AER has approved all these changes in JGN"s tariff proposals. The EMRF also welcomes these developments other than the removal of the "first response" tariff (discussed below). The publication of a TSS is also welcome, as this will assist members to plan their own operations.

The members of EMRF look forward to the future discussions with JGN over its tariff proposals.

6.2.2 JGN's tariff pricing objectives

In addition to meeting the requirements of the NGR, JGN set out the following tariff objectives that would guide their approach to network tariffs. They are:

- recover the efficient costs of operation;
- keep gas competitive compared to other fuel options;
- promote efficient use of the network and treat customers equitably
- provide stability in the network and in end-retail prices; and
- provide simplicity and transparency.[152]

What is missing from this statement of objectives, is that pricing must be efficient and to reflect the equitable allocation of costs. The EMRF considers that these are essential aspects which should be included.

6.2.3 The AER's response to JGN's tariff proposal.

The AER has accepted those principles and the basic structure of JGN's proposed tariffs, the tariff classifications and the allocation of revenues and

[152] Jemena Gas Networks, Fact sheet, "Our proposed network prices and charges for Residential and Commercial customers", February 2015. http://jemena.com.au/Gas/Jemena/media/JemenaGasNetworksMedia/Community-Engagement-Document/Our-2015-plan/Fact%20Sheet%20-%20Our%20proposed%20network%20prices%20and%20charges%20for%20residential%20and%20commercial%20customers%20-%20Revised%20proposal.pdf

costs to the reference tariffs. The final prices will, however, depend on the outcome of the AER's final decision.

The more significant amendments made by the AER in its draft decision include:[153]

- AER rejects JGN's proposal for including a mechanism to add or remove tariffs within the regulatory period; the AER states that there is already sufficient provision with the NGR for JGN to amend tariffs; and

- AER rejected JGN's proposal to include a fixed principle to all for cross-period pass throughs, where the costs recognised in an approved pass through can be recovered in tariffs adjustments in the next regulatory period.

6.2.4 JGN's approach to Tariff D network prices

In its original submission to the AER, the EMRF expressed its concern that while JGN proposed significant reductions in tariffs for all Tariff V consumers, it was offsetting these by increases in the tariffs to large consumers on Tariff D by some 13% across the AA2 period.

JGN's stated rationale for this appears in JGN's 2014 TSS as follows:[154]

> *We seek to apply consistent and steady price movements for our demand customers to provide certainty and assist in long-term planning. For this reason demand customers do not experience the same level of increases as the volume market in 2010-15 and are not subject to the 2015-20 price decreases applicable to the volume market.*

JGN is correct in stating that Tariff D customers value "certainty" in gas network pricing. However, the implication that JGN appears to draw from this is that Tariff D customers are, therefore, accepting of the proposal that they receive no network price decreases in AA2, despite the reduced overall revenue requirements.

JGN has not provided convincing support for this assumption that stability means CPI type price increases over the next period for Tariff D consumers. The EMRF is of the firm view that a preference for certainty does *not* mean a preference for a 13% increase in network prices over the

[153] JGN, *Revised 2015-20 Access Arrangement,* February, 2015, p 117 -118 (@ 569 – 585).
[154] Jemena Gas Networks (NSW) Ltd, *2015-20 Access Arrangement Information Appendix 1.8, Tariff Structures Statement*, 30 June 2014, p 39. [JGN, *Tariff Structures Statement*, June 2014).

next 5 years, particularly given all the other challenges facing large Tariff D consumers.

However, JGN has separately indicated that in assessing the Tariff D charges it wished to: “restore the proportion of revenues closer to historical levels which were in accordance with network utilisation”.[155]

JGN’s claim was that its revenue from Tariff D customers declined to 8.5% over 2009-14 because JGN altered its pricing strategy to reduce price shocks for large users from the carbon tax and recovery of revenues from JGN’s successful appeal to the Tribunal. JGN therefore, wished to restore the share of revenue from Tariff D to historical levels of 10.5%.

The EMRF also noted the forecast decline in the MDQ for Tariff D from around 337 TJ in 2014 to around 267TJ by 2020.[156] JGN also states that the long run marginal cost for D tariff customers is zero as they do not impose future costs on the network system and D tariff customers frequently make a contribution to their initial connection:[157]

> *Our model has produced LRMC values of zero for the demand market as there is no growth in this market during the forecast horizon. That is, we do not expect the demand market to drive incremental growth-related investment on our network. This is consistent with the incremental cost of the shared network being specific to individual demand customers’ characteristics. These customers also pay material charges for any incremental cost when they connect or materially grow their usage.*

EMRF concludes form this that if the overall revenue requirement for JGN is reduced in for the next period relative to the current period, then at the very least D tariff customers, who have not added to the costs of the network, should receive some tariff benefit.

A reduction in network tariffs to large users would have the benefit of stabilizing total gas prices to Tariff D customers, given the impact of increased contract gas costs on this sector. Retaining the viability of D tariff customers is as important, or more important than expanding the investment in V tariff customers.

This is not to say that the EMRF opposes price reductions for Tariff V customers. The EMRF acknowledges that they have faced substantial increases in the past. However, it is essential that in an effort to expand its

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155 See AER, *Draft Decision, JGN 2015-20 Access Arrangement*, Attachment 10 – Tariff Setting, November, 2014, p 10-12. The AER is citing a letter from JGN in response to an information request, dated August 2014 (p 4).
156 EMRF, *Response to JGN 2015-20 Access Arrangement proposal*, August 2014, p 101.
157 JGN, *Tariff Structures Statement*, June 2014, p 31.

Tariff V market, JGN does not effectively pass the additional expenditures to the Tariff D market which it appears to do.

The EMRF has also noted in this current submission, its concern that JGN's plans to expand the Tariff V customer base are not necessarily a cost benefit to the network consumers as a whole unless the revenue from these additional customers fully recovers the incremental fixed and variable costs of their additional network services.

This is even more of a concern given that average use is declining (particularly on JGN's forecasts), and at the same time, JGN has reduced the fixed charge component of its V tariffs. In other words JGN is relying on the volume component of the tariff to recover the fixed costs, but this can lead to distortions and cross subsidies if new consumers have a lower average consumption than existing consumers.

The EMRF is therefore very concerned that JGN has "squared the circle", by charging more than is otherwise necessary to larger users. It is important the AER examine this issue in more detail than it appears to have done in its draft decision.

6.2.5 The EMRF's response to the AER's draft decision

The EMRF is not satisfied with the AER's response to the concerns raised by the EMRF and other large users. The AER appears to have accepted JGN's rationale for increasing Tariff D prices while implementing large decreases in Tariff V prices without appropriate level of critical appraisal.

In addition to the comments above that JGN's stated rationale lacks substance, the EMRF would state the following:

- JGN's proposal is inconsistent with the observations that the LRMC of supplying Tariff D customers is zero;

- To the extent JGN did stabilize tariffs to large users in the current period (and there is no substantive evidence to state that this is the case), they did so only after substantial increases in earlier periods;

- Large users are more exposed to the future shocks of gas price increases than smaller users given the extent to which the industrial and manufacturing processes are built around high cost and long-life gas equipment;

- It does not make sense to allocate tariffs on the basis of some historical assessment. For one thing, Tariff D customer numbers have been declining as has their average consumption. This fact alone would lead to a lower share, rather than any pricing issue. Neither the AER or JGN attempt to separate out changes in the customer mix from changes in pricing "equity";

- Large users have contributed to the cost of the gas network required to supply them (as noted by JGN), and are not adding to JGN's opex or capex requirements. Given this, the net value of the assets to supply them is depreciating and large users should get the benefit of this.

6.2.6 Removal of the "first response" tariff

As noted in the EMRF's original response to JGN's proposal, the EMRF is disappointed that JGN has chosen to remove the "first response tariff".

It is also disappointing that the AER has accepted this proposal, and would seem not to have considered the EMRF's views on this.

One of the difficulties with the tariff in the past is that it has not been strongly promoted; a new tariff such as this needs active promotion by JGN with efforts to explain its operation and benefits to both the customer and JGN.

In any case, the EMRF argues that it is not the time now to abandon this tariff. Analysis by AEMO and others suggests that there is a possibility of winter shortages of supply in NSW once the LNG facilities are fully operational. The first response tariff provides a market mechanism to allow efficient response to any such short term shortages. This is far preferable to forced interruption of large customers (at least as the first response to a shortage) using a blunt instrument of interruption tables and the like.

Indeed such blunt instruments are exactly the direction the market should not be taking. The EMRF urges both JGN and the AER to reconsider this proposal – all consumers will ultimately benefit from the market based flexibility that this tariff could provide once properly promoted.