Jemena Gas Networks (NSW) Ltd

Initial response to the draft decision

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Overview

On 25 August 2009 Jemena Gas Networks (NSW) Ltd (JGN) submitted to the AER its original access arrangement revision proposal for the JGN network for the next access arrangement (AA) period. On 10 February 2010 the AER issued its draft decision. This document sets out JGN's initial response to the AER's views in its draft decision and the ways in which JGN has amended its proposed access arrangement revision.

Significance and challenges of this review

This is the first AA review that the AER has undertaken for a large gas distribution business and the first review JGN has participated in under the new National Gas Law (NGL) and National Gas Rules (NGR). All participating parties—JGN, the AER and stakeholders—are meeting the challenges of dealing with this new regime. JGN is actively engaging with the AER and stakeholders to foster a common understanding of the complex issues surrounding its AA review and the issues raised by the draft decision.

JGN's commercial offering

JGN's access arrangement is its commercial offering to users and reflects its business direction for the next AA period. JGN has considered the AER's draft decision carefully and the reasons that the AER has provided for its preferred amendments in the light of the NGR and the NGL and what is in the best long term interests of its users and customers. Accordingly, it has incorporated some of the AER's amendments and not others. This document sets out JGN's reasoning.

Major need for new capital expenditure

On the basis of extensive analysis and risk assessment, JGN's network remains in significant need of increased investment in system reinforcement, refurbishment and replacement to mitigate capacity constraints, maintain reliability of supply and meet new customer demand. Many of its network and non-network assets are reaching the end of their lives. Wilson Cook, the AER's consultant, examined JGN's analysis and agreed that its proposed capital program for the next AA period was reasonable in scope and in timing. However, the capital expenditure allowance in the draft decision is not sufficient to meet these needs, even making an extreme assumption of no real change in unit costs between the periods.

In the light of JGN's revised demand and inflation forecast and better escalation and cost estimates, JGN's forecast capital expenditure is $891 million.

In and with this document, JGN elaborates on its comprehensive planning, design, estimating and staged approvals process, and provides business case detail and its capitalisation policy. This will provide the AER with the information necessary for it to understand that JGN's forecast costs do reflect that which would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost. It will also confirm that JGN's forecast capital expenditure relates to projects that are capital in nature.

Weighted average cost of capital

The commercial viability of new investment is largely dependent upon the return on capital JGN is allowed in its AA and JGN proposes a nominal vanilla WACC of 10.86%.

In this revised AA proposal, JGN's cost of capital calculation incorporates many of the AER's amendments, including moving to a post-tax nominal WACC, revised market risk premium and gearing ratio, and inflation forecasts based on reserve bank targets.

JGN has retained the Fama French model in its calculation of cost of equity because, not only is it well accepted, but more importantly it provides a demonstrably better estimate than the capital asset pricing model.

JGN's proposed cost of debt reflects the risks of an efficient gas distributor and the prevailing market conditions. JGN has built on recent work to identify the best estimate of the debt risk premium from available data service providers and puts forward a new methodology that incorporates a number of robust tests. One key element of the methodology is to test the appropriate extrapolation of observed yields. Gas distributors are inherently more risky businesses than electricity distributors and JGN provides further conceptual and empirical evidence to demonstrate this.

JGN reaffirms that 0.2 is the best estimate of gamma on a reasonable basis in the current circumstances. It responds to the AER's criticism of recent studies and submits new evidence in support of its view.

Operating expenditure

The AER and JGN accept that the base year roll forward approach is the best basis for forecasting most operating expenditure that complies with the NGL and NGR. JGN and the AER differ on the approach to establish the efficient base-year cost base, which is the starting point. As the revealed cost method has significant advantages, JGN again uses that as the basis of the majority of its forecast.

The asset management agreement that JGN has struck with Jemena Asset Management (JAM) provides substantial benefits to JGN, its users and its customers in terms of both price and service. In this document, JGN puts forward both an assessment framework and its application to confirm that the price JGN will pay, and the service it will receive, is the best it could achieve.

Significant new evidence that JGN brings forward to support its operating expenditure forecast includes an external validation of its actual costs, more detail to substantiate its step changes, and better escalation estimates.

The benchmarking of JGN continues to show that its costs compare very favourably with its peers. This may in part reflect the significant economies of scale and scope from which JGN is able to benefit through outsourcing to JAM.

JGN's new and legacy services

In its draft decision, the AER agreed that JGN's new haulage and meter data reference services are likely to be sought be a significant part of the market and meet the requirements in the rules.

JGN has now removed its existing reference (legacy) services from its AA because they cannot be sustained with the short term trading market (STTM) scheduled to commence on 4 June 2010.

Demand forecasts

The AER's consultant, ACIL Tasman, confirmed that the methodology used to determine JGN's demand forecast is sound. JGN has now updated its forecast, and has specifically taken account of energy policies that will come into effect in the future.

Regulatory innovations

JGN continues to include in its AA some important regulatory innovations designed to provide real benefits to users and customers.

There are presently 600,000 homes and businesses within JGN's distribution area that have no reticulated gas supply. JGN's market incentive mechanism will significantly increase the likelihood of gas being available to a proportion of those homes and businesses over time, when otherwise they would remain without supply.

JGN's W factor is intended to adjust prices to compensate for the effects on demand of weather cooler or warmer than normal. It is a simple and symmetrical mechanism to smooth the impact of weather on revenue, to some extent, for both customers and JGN—weather being a factor over which neither has control.

Extension of AER's powers

The AER already has extensive powers to gather information and to approve access arrangements in a new regulatory regime carefully designed by policy makers in consultation with industry. JGN has not established in its AA additional new powers for the AER to gather information and require JGN to justify its expansions and extensions during the AA period because this is neither necessary nor appropriate from a regulatory policy perspective.

1 Introduction

- JGN has submitted its revised revisions for its access arrangement: its commercial offering to the gas market
- Along with its revised AA revision documentation, this document is JGN's initial response to the AER's draft decision
- Several framework and approach issues arise from the draft decision including those related to this being the first application of the NGL and NGR to a large distribution business and the application of the fit-for-purpose decision making model
- JGN looks forward to working with the AER and users in the lead up to the final decision.

1.1 JGN's amended AA revision proposal package

In response to the Australian Energy Regulator's (**AER**) draft decision (**draft decision**) on Jemena Gas Networks' (**JGN**) proposed revised access arrangement (**AA**) for the NSW gas distribution network (**JGN network**) for the period 1 July 2010 to 30 June 2015, JGN submits its **revised AA revision proposal** consisting of:

- *revised access arrangement* – JGN's revised AA revision
- *revised reference service agreement (***RSA***)* – the contractual terms and conditions (**T&Cs**) upon which JGN proposes to provide network services, which forms part of JGN's AA
- *revised access arrangement information (***AAI***)* – information required in accordance with the relevant national gas rules (**NGR**) requirements[1]
- *initial response to the draft decision* – this document with appendices, which is the substantiation and rationale for JGN's revised AA revisions and elaborates on key aspects of the revisions JGN has incorporated in its AA.

This chapter sets out the background to the AA revision process to date, the purpose and structure of JGN's response submission, and the general comments that JGN wishes to make on the draft decision at this stage.

[1] NGR, rules 42, 43, 72, and 73.

1.2 Background

1.2.1 JGN's original AA revision proposal

On 25 August 2009 JGN submitted to the AER its original AA revision proposal for the JGN network for the next AA period, which was made up of the following documents:

- *revised access arrangement* – JGN's original AA revisions
- *reference service agreement* – the contractual terms upon which JGN originally proposed it would provide network services, and which forms part of JGN's AA
- *access arrangement changes* – a description of how JGN's original proposed AA differed from its current AA
- *access arrangement information* – the substantiation and rationale for the original proposed AA with appendices that elaborated on key aspects of the original AA revision and included information required in accordance with the relevant NGR requirements[2].

These submission documents together presented JGN's proposed cost of service, prices for cost recovery, and terms and conditions of network access. The AER published them on its website[3] on 15 September 2009.

1.2.2 Summary of AER's draft decision

On 10 February 2010 the AER issued its draft decision[4] under rule 59(1) of the NGR. This followed a public forum on JGN's initial proposal[5], public submissions on JGN's initial proposal and two round table discussions[6].

The AER's draft decision was not to approve the proposed AA revision that JGN submitted in August 2009. The amendments the AER stated in the draft decision that would be required to the AA in order to make the proposal acceptable to the AER included a number of amendments to the key cost, pricing and access terms of JGN's AA revision.

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2 NGR, rules 42, 43, 72, and 73.

3 http://www.aer.gov.au/content/index.phtml/itemId/730676

4 Draft decision.

5 The AER held a public forum on JGN's original AA revision proposal in Sydney on 23 September 2009.

6 The first round table on 27 November 2009 focussed on terms and conditions. The second round table on 11 December 2009 focussed on JGN's proposed tariffs and tariff structures. Both round tables were attended by the AER, JGN and retailer representatives invited by the AER.

The AER has given JGN until 19 March 2010 to respond to the AER's draft decision with any revised AA revision proposal, with submissions on the draft decision required by 28 April 2010.

1.3 Purpose, conventions and structure of this document

1.3.1 Purpose

This document sets out JGN's initial response to the views the AER has put in its draft decision and the reasons for the amendments that JGN has incorporated in its proposed AA revisions. It comprises an initial response to the draft decision as well as addressing each of the amendments that the AER lists in the draft decision as being required in order to make the proposal acceptable to the AER, on a chapter by chapter basis.

During the course of the AER's consultation on its draft decision, in response to the AER's questions, or if new relevant information - for example, stakeholder submissions - becomes available to JGN, JGN may seek to respond to that information or material.

1.3.2 JGN is the network owner

Jemena Gas Networks (NSW) Ltd (or JGN) owns and operates the JGN network.

Throughout the draft decision the AER referred to JGN Gas Networks (NSW) Ltd as 'Jemena'. JGN requests that the AER refers to JGN Gas Networks (NSW) Ltd as 'JGN' in its final decision and related documents.

JGN is the correct legal entity. Using the name 'JGN' is consistent with JGN's submissions and correspondence on this matter. It will also help avoid stakeholder confusion between JGN and other entities within the Jemena Limited and SPI (Australia) Assets Pty Ltd group, such as Jemena Electricity Networks (Vic) Ltd and Jemena Asset Management Pty Ltd.

1.3.3 Access arrangement periods

This document refers to several different access arrangement periods. These are both defined below and in the glossary:

- **previous AA period** – the period 1 July 2000 to 30 June 2005
- **current AA period** – the period 1 July 2005 to 30 June 2010
- **next AA period** – the period 1 July 2010 to 30 June 2015
- **subsequent AA period** – the period 1 July 2015 to 30 June 2020.

This naming convention matches that used by JGN in its August 2009 proposal.

1.3.4 Monetary amounts

All monetary amounts presented in the AAI are expressed in real 2010 dollars, are in millions of dollars and apply to 1 July to 30 June regulatory years unless otherwise stated.

1.3.5 Structure

The structure of this document mirrors the structure of the AER draft decision so that it can be easily reconciled to the AER draft decision and aid reader understanding. Each chapter addresses the equivalent chapter of the AER draft decision and discusses JGN's original proposal, the AER amendments relevant to the content of that chapter, JGN's response to those amendments and any amendments made to JGN's revised AA and AAI to address the matters raised in the draft decision.

The chapters in this document are as follows:

- Chapter 2 Pipeline services
- Chapter 3a Capital base – RAB
- Chapter 3b Capital base – Forecast capital expenditure
- Chapter 4 Depreciation
- Chapter 5 Rate of return
- Chapter 6 Taxation
- Chapter 7 Incentive mechanism
- Chapter 8 Fixed principles
- Chapter 9 Operating expenditure
- Chapter 10 Total revenue
- Chapter 11 Demand forecasts
- Chapter 12 Tariffs – distribution pipelines
- Chapter 13 Tariff variation mechanism

- Chapter 14 Non-tariff components

1.3.6 *Amendments to the access arrangement proposal and information*

It should be noted that where JGN has incorporated an amendment to the AAI in response to an amendment the AER stated in the draft decision was required in order to make the proposal acceptable to the AER, this should not be taken as JGN necessarily agreeing that the NGR provides the AER with the ability to state in its draft decision the nature of the amendments that would be required to the AAI in order to make the proposal acceptable to the AER. JGN also reserves its position in relation to whether the NGR provides the AER with the ability to make amendments to JGN's AAI in the event the AER does not approve JGN's revised AA revision.

1.4 Framework and approach issues associated with the draft decision

While other chapters of this document deal with the nature of JGN's revised AA revision and specific issues in the draft decision, this section sets out a range of general framework and approach issues associated with the draft decision.

1.4.1 *First application of the NGL and NGR to a large gas distribution business*

This is the first review JGN has participated in under the new NGL and NGR and its first review with the AER. Both organisations and stakeholders are doing their best to deal with the challenges this situation creates.

On a strict interpretation of the NGR, the minimum regulatory process set out in the NGR, on its own, provides very limited express opportunities for the parties to interactively identify and explain the significant issues that will arise, and to achieve the level of understanding necessary for robust decision making. The need for open and ongoing communications between the AER and JGN is critical as part of this review process, particularly in light of:

- the large and complex nature of JGN's business
- the fact that JGN is the first large gas distribution business the AER has reviewed
- the sophisticated—and to some degree untested— economic concepts in the NGL and NGR, especially in a distribution context.

Accordingly, JGN has made substantial efforts to inform the AER and stakeholders about the nature of its business through its AA revision proposal, letters, meetings and forums.[7] It has done this in a manner that is transparent and that is designed to provide JGN with a better understanding of the AER's considerations and processes, as well as to try to proactively fill any information or interpretation gaps of which JGN is aware and to comply with our regulatory obligations. Since the draft decision, JGN has sought to clarify with the AER its information requirements[8] and the claims made by the AER in its draft decision that JGN made errors in the preparation of its proposed AA revision.[9]

JGN's original AA proposal and its response to the AER's regulatory information notice were comprehensive and, in JGN's view, fully compliant with the requirements of the NGL and NGR. They also reflected JGN's understanding at the time of the AER's intended approach to the assessment of each aspect of JGN's AA. In its draft decision, the AER has expressed a range of different information requirements and JGN has endeavoured to take these on board for the purposes of its revised AA proposal.

1.4.2 AER errors in the draft decision

In JGN's view, the AER has made several material errors in its draft decision and, given the limitations of the statutory process, JGN has brought these to the AER's attention at the earliest possible time.[10] The most significant errors relate to the AER's:

- calculation of JGN's regulatory asset base roll-forward
- selection of the debt risk premium
- deduction of JGN's one-off operating expenditures in the base year
- escalation of JGN's overhead and administration costs
- calculation of JGN's total unaccounted-for gas cost.

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7 For example: Letter from JGN to the AER dated 19 February 2010, *Provision of information from JGN*; letters from JGN to the AER dated 19 February 2010, 1 March 2010 and 8 March 2010, *Clarifications of AER reasons for draft decision*; letter from JGN to the AER dated 3 March 2010, *Notification of identified AER errors in draft decision*; and meetings with AER staff on 24 February 2010 and 4 March 2010; JGN provided confidential briefings to the AER on 14 August 2008, 28 August 2008, 5 September 2008, 11 May 2009, 26 June 2009 and 4 November 2009; JEN made a presentation at the AER's public forum on 23 September 2009, JEN attended AER round-table forums with users on 27 November 2009 and 11 December 2009, JEN also initiated regular meetings with AER staff until the lodgement of its original AA proposal.

8 Letter from JGN to the AER dated 19 February 2010, *Provision of information from JGN*.

9 Letter from JGN to the AER dated 3 March 2010, *References in the draft decision to errors in JGN's proposed access arrangement revisions*.

10 Letter from JGN to the AER dated 3 March 2010, *Notification of identified AER errors in draft decision*.

Where appropriate, JGN has addressed these errors in this document.

1.4.3 *AER reasoning in the draft decision*

The draft decision contains a very large number of issues for JGN to consider and respond to in a short period of time. JGN has done its best to address all the issues based on its understanding of the reasoning in the draft decision.

There are a number of areas in the draft decision in which the AER's reasoning is not apparent to JGN, and in relation to which JGN sought clarification from the AER within the time available.[11]

Beyond the reasoning the AER has provided in its draft decision, and the explanations the AER provided subsequently, JGN reasonably assumes that there are no other working papers that informed material elements of the draft decision and that contained relevant research and/or underlying analysis not contained in the draft decision.

1.4.4 *"Fit for purpose" decision making framework*

The Second Reading Speech noted the following important points in connection with the 'fit for purpose' framework:

> The key aspect of the 'fit for purpose' framework is that it best balances the aims of reducing the risk of regulatory error, balancing the interests of consumers and the service provider, and allowing for the regulatory regime to evolve where required.

The 'fit for purpose' framework acknowledges that in a service provider's proposal, there is such a range of dimensions and inter relationships between revenue and price components, that the regulatory framework should retain the capacity to require the regulator to have a presumption of acceptance, have discretion to determine and outcome or apply a more specific test to different elements of the proposal. Under this model, the regulator is not given absolute discretion for different elements of the proposal but is guided in its decision making by the National Gas Objective, the revenue and pricing principles, and the fit for purpose framework established in the NGR.[12]

It is only after the AER has fully considered the materials submitted by JGN and determined that JGN's proposal is not consistent with the requirement of the NGR that the AER may then go on to consider the nature of the amendments that would be required to JGN's proposal in order for it to comply with the NGL and the NGR.

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[11] Letters from JGN to the AER dated 19 February 2009, 1 March 2010 and 8 March 2010, *Clarification of AER's reasons for draft decision*.

[12] Second Reading Speech, National Gas (South Australia) Bill 2008, The Hon. P.F. Conlon (Elder—Minister for Transport, Minister for Infrastructure, Minister for Energy).

That the AER must start with the service provider's proposal and determine whether the proposal is consistent with the NGL and NGR before considering if any amendments are required to make the proposal consistent with the NGL and NGR is clear from rule 40. This rule sets out the AER's discretion in the decision making process relating to access arrangement proposals.

- Subrule 40(1) provides that where a service provider's proposal is consistent with the requirements of the NGL and the NGR, and the AER has no discretion, the AER must accept the service provider's proposal

- Subrule 40(2) provides that if the AER is satisfied that a service provider's proposal complies with the requirements of the NGL and the NGR and is consistent with any applicable criteria prescribed by the NGL and the NGR, the AER may not withhold its approval to an element of an access arrangement where is AER has limited discretion

- Subrule 40(3) provides that where the AER has full discretion, the AER may exercise a discretion to withhold approval to an element of an access arrangement if, in the AER's opinion, a preferable alternative exists that complies with the NGL and the NGR and is consistent with applicable criteria prescribed by the NGL and the NGR

Therefore, what is required under each of these subrules is an assessment of the service provider's proposal first, and then a consideration as to whether any departure by the service provider's proposal is necessary to bring that proposal into compliance with the NGL and NGR. Where a service provider's proposal complies with the requirements of the NGR and the NGL, the AER must accept the proposal where the AER has no discretion or limited discretion. In these cases, there is no ability for the AER to consider whether a preferable alternative to that put forward by the service provider exists.[13]

In relation to a number of areas in the draft decision where the AER has required amendments to be made to JGN's proposal, it is apparent from the draft decision that the AER has not fully considered JGN's proposal using a clear analytical framework. On these occasions in the draft decision, the AER has concluded that JGN's information is insufficient and has gone straight to what it considers should be contained in the proposal without considering whether its own proposal complies with the NGL and NGR. Examples include:

- *cost of equity* – The AER set out why it believes the Fama-French cost of equity model that JGN proposed is not well accepted, but did not demonstrate why the capital asset pricing model provides the best estimate

[13] See also: Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 7.

on a reasonable basis and, even more importantly, enables JGN to recover its efficient costs.

- *concrete and polyethylene escalators* – The AER determined that JGN's proposed escalators were not arrived at on a reasonable basis and then substituted JGN's value for each of these escalators with zero. The AER did not analyse its estimate of zero nor did it not determine that zero was the best estimate formed on a reasonable basis.

- *capital expenditure forecasts* – From most categories of JGN's capital expenditure, the AER accepted that the scope of JGN's capital program is reasonable, but rejected JGN's cost estimates. It then determined JGN's expenditure forecast by applying an historical trend. Again, the AER did not analyse its forecast and did not determine that it complied with the capital expenditure tests in the NGL and the NGR and whether it was the best estimate formed on a reasonable basis.

JGN believes that the appropriate alternative approach is to assess each aspect of JGN's proposal using a sound and defined analytical framework that matches the nature of an incentive-based regulatory regime. To assist the AER to do this, this document sets out some analytical approaches that JGN considers should be adopted and demonstrates how the information that JGN has provided enables provides the AER with a basis upon which it should be satisfied that JGN's proposal complies with the relevant rules.

1.4.5 Establishment of new AER powers though JGN's AA

In the draft decision, the AER proposes to establish a number of new information gathering powers that are not subject to appropriate checks and balances and new investment approval powers that increase the scope of network regulation.[14] This is inappropriate and unnecessary. JGN's access arrangement is its commercial offering to the market, and the AER's information and approval powers are better located in the NGL and the NGR as a matter of regulatory policy.

In the draft decision the AER indicated that it would require the following amendments to JGN's AA that relate to the maintenance and provision of information to the AER:

- *statement of costs* – a requirement that JGN maintain and update a detailed "statement of costs" relating to opex (amendments 9.7 and 9.8);

[14] See page 221 of the draft decision in relation to the maintenance and provision of information in connection with JGN's assessment of JAM's performance; and page 348 in relation to information requirements associated with expansions and extensions that have been commenced, are in progress and / or are completed during a financial year

- *monitoring of JGN's outsourcing contractor* – a requirement that JGN maintain and provide to the AER as part of proposed revisions to the AA, information including details of:
  - Jemena Asset Management's (**JAM's**) efficiency targets for the period
  - actual costs achieved against budgets
  - details of any JAM cost overruns authorised by JGN
  - details of JAM's performance in regards to the risk and benefit sharing mechanism
  - the basis upon which the performance margin for JAM was calculated and applied for the period (amendment 9.7)
- *monitoring and seeking justification of JGN's extensions and expansions during the AA period* – A requirement that no later than 20 business days following the expiration of its financial year JGN must notify the AER of all extensions of low or medium pipelines and expansions of the capacity of the Network during that financial year—including all expansions commenced, in progress and completed—and the notice must describe each extension and set out why this was necessary (amendment 14.34).

The NGL already provides the AER with extensive powers to gather information from service providers, such as JGN, and related providers that is reasonably necessary for the performance or exercise of the AER's functions or powers under the NGL or the NGR.[15] The NGL also sets down a range of procedural checks and balances that require the AER to have regard to the relevant costs, that require the AER to consult in a certain manner, and that protect the provider's confidentiality.[16]

The NGL and NGR also set down powers for the AER to determine access arrangements, which create certain incentives and transparency for investment decision making. Policy makers designed this regime carefully in consultation with industry and the AER, with regard for the nature of gas networks, the market in which they operate, and most importantly their ability to make their own business decisions in response to regulatory incentives and other factors.

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15 National gas law, section 48(1).

16 National gas law, sections: 30 (confidentiality); 48 (service and making of regulatory information instrument); 49 (additional matters to be considered for related provider regulatory information instruments); 50 (AER must consult before publishing a general regulatory information order), 52 (Opportunity to be heard before regulatory information notice is served), 324 (authorised disclosure of information given to the AER in confidence).

It is therefore inappropriate for the AER to seek to establish additional powers without regard for the whole regulatory design, and to duplicate and expand its regulatory reach.

It is also JGN's view that it is beyond the legal scope of an access arrangement to provide for such powers.

1.5 Leading up to the final decision

1.5.1 Consideration of confidential information

JGN expects that the AER will have regard to the genuinely confidential information that JGN or stakeholders submit to the AER.

JGN has claimed confidentiality over some of the information JGN has provided to the AER as part of the AER's review of JGN's AA revisions. JGN has restricted its claim for confidentiality to genuinely confidential information. JGN does not believe that its claims for confidentiality have any relevant impact on the AER's ability to properly assess whether JGN's proposal is compliant with the NGL and the NGR. If the AER does consider that its ability to fully assess any aspect of JGN's proposal is hampered by JGN's confidentiality requests, JGN would appreciate being notified of this, and as early as possible, so that JGN can consider whether such information can be made available on a restricted or limited basis.

JGN also notes that some submissions from stakeholders containing confidential information have been made to the AER. JGN must be afforded the opportunity to respond to all materials relevant to the AA review process. To the extent a third party wishes to claim confidentiality in relation to genuinely confidential information, JGN is willing to work with the relevant stakeholder and the AER to determine an appropriate basis for the disclosure of that information which balances the commercial concerns of the stakeholders and JGN's interests in the AA review process.

1.5.2 Consideration of stakeholder submissions and new information/analysis available after the draft decision

JGN must be afforded a reasonable opportunity to respond to all materials that are relevant to the AA review process, including any new information the AER intends to take into account or any change in thinking on issues upon which the AER has not previously consulted JGN.

Where stakeholders raise new issues in submissions responding to JGN's revised AA revision, or the AER conducts further analysis as a part of making its final determination, JGN has a reasonable expectation that it will have an opportunity to review and, where appropriate, respond to, such submissions and new information prior to the final decision.

1.5.3 Maintaining constructive contact

JGN continues to welcome questions and comments from the AER and from stakeholders on its revised AA revision proposal. JGN will use its best endeavours to address the issues raised and provide additional information if it is needed.

JGN encourages the AER to continue to have a dialogue with JGN and not wait until its final decision to express any view it has about the potential adequacy or reliability of the information JGN has provided. In this way, JGN can respond in a timely manner, especially to correct any misconceptions, and the AER and other relevant stakeholders will be better informed for its final decision.

2 Pipeline services

- In its original proposal, JGN proposed a significant simplification of its reference services through provision of a single haulage reference service and a meter data service.
- While in its draft decision the AER proposes to approved this simplification, it also required JGN to include legacy services and ancillary fees as reference services.
- JGN considers it is workable to incorporate ancillary fees into its proposed reference services and has revised its AA proposal accordingly.
- The AER's requirement for legacy services to be reference services is incompatible with the impending Short Term Trading Market (STTM). The legacy services as they are defined in existing contracts by reference to service scope, user obligations and JGN obligations cannot be reconciled with a STTM environment. The consequence of this is that no user who is also an STTM participant will continue to seek legacy services as they are defined in existing contracts following the introduction of the STTM prior to the next AA period. Legacy services are therefore not likely to be sought by a significant part of the market and do not meet the definition of reference services in rule 101 of the NGR.

2.1 Summary of JGN original proposal

In its original AA revision proposal, JGN outlined the reference and non-reference services that it intended to provide. The proposed reference services were:

- *haulage reference service* - a service for transportation of gas by JGN through its network to a single eligible delivery point for the use of a single customer
- *meter data service* - a service for the provision of meter reading and on-site data and communication equipment to a delivery point.

This was a significant simplification from the current AA that provides for seven separate reference services. JGN does not propose to offer reference services available under the current AA for new service requests and, for the reasons set out in this chapter cannot continue to provide the services as they are defined in existing contracts for existing users.

In its original AA revision proposal, JGN proposed a bulk transition mechanism to enable existing users to move from old contracts to the new RSA for the new AA services.

In addition to the two proposed reference services outlined above, JGN proposed the continuation of non-reference services:

- interconnection of embedded network service
- negotiated services.

JGN also proposed the following ancillary fees:

- *request for service* – This charge is for processing the response to a user or prospective user when they request a new, additional or changed service.
- *special meter read* – This charge is for reads requested by a user or prospective user out of the usual meter reading route or schedule used for an ordinary read. This service must be scheduled with a minimum five day notice period.
- *temporary disconnection* – This charge is for temporary disconnection of supply at the request of the user where temporary isolation of supply is required. The specific method used to ensure the isolation of supply is at the discretion of JGN. The charge for temporary disconnection includes the cost of subsequent reconnection.
- *permanent disconnection* – This charge is for disconnection of supply where the user requests that the meter is not to be moved or removed. The specific method of permanent disconnection is at the discretion of JGN who will ensure that the site is left in a safe condition. A request for reconnection must be made as a new connection request.
- *decommissioning and meter removal* – This charge is for the permanent decommissioning of a network connection where a request is made for the removal of the meter. The specific method of disconnection is at the discretion of JGN who will ensure that the site is left in a safe condition.

JGN allocated its total revenues to its reference and non-reference services in accordance with the NGR.

2.2 Summary of AER draft decision

Table 2-1 sets out the amendments that the AER stated in its draft decision it would require in order to make the proposal acceptable to the AER in relation to JGN's pipeline services.

Table 2-1: Amendments the AER required in its draft decision – services

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
2.1	Amend the access arrangement proposal to delete the definition of "Reference Service" in clause 1.1 of Schedule 3 and replace it with the following: **Reference Service** means the Ancillary Reference Services, the Legacy Services, the Haulage Reference Service, and, until the Meter Data Service Date, the Meter Data Service	Partially incorporated	Section 2.3
2.2	Amend the access arrangement proposal to delete the definition of "Reference Service" in clause 1.1 of Schedule 1 and replace it with the following: Reference Service means: a. the Ancillary Reference Services; or b. the Haulage Reference Service; or c. Legacy Services; or d. The Meter Data Service	Partially incorporated	Section 2.3
2.3	Amend the access arrangement proposal to include the following in clause 1.1 of Schedule 3: **Ancillary Reference Service** means the ancillary services described at H of Schedule 2 to the Access Arrangement.	Incorporated with modification	Section 2.3.1
2.4	Amend the access arrangement proposal and the access arrangement information to reflect amendments 2.1-2.3	Partially incorporated	Section 2.5

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
2.5	Amend the access arrangement proposal and the access arrangement information to specify the other terms and conditions on which the legacy services will be provided.	Not incorporated	Section 2.4
2.6	Amend the access arrangement proposal to include the following in section 1.1 of Schedule 1: Legacy Service Agreement means an agreement between the Service Provider and the User for the provision of a Legacy Service.	Not incorporated	Section 2.4

JGN's proposals for the haulage and meter data reference services were accepted by the AER in its draft decision.

2.3 JGN response to AER draft decision – ancillary fees

2.3.1 The nature of reference and non-reference services

JGN's approach to the distinction between reference services and non-reference services is consistent with the intended application of what are now rules 48(c) and 101, as expressed by the Standing Committee of Officials in the course of developing the NGR. That is:

> The NGR requirements for the specification of reference services in access arrangements will return to a future-looking approach, where access arrangements must specify as reference services all services "that are likely to be sought by a significant part of the market." [17]

2.3.2 Inclusion of ancillary fees as a reference service

For its revised AA revision, JGN has modified the definitions of its proposed reference services and the wording of the RSA so that it is clearer that these activities and charges are provided as part of JGN's reference haulage service or meter data service. This is somewhat different to the AER's suggested amendment. However, it achieves the intent of including those commonly requested activities within the reference services scope.

[17] Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 9.

JGN considers that ancillary fees relate to services that are not discrete or separate reference services in the context of delivering pipeline services. These relate to ad hoc activities that users of JGN's pipeline services may require from time to time.

For example, a user taking a haulage reference service may require a temporary disconnection service if its customer is not paying its bills. This is not a function required to provide the haulage reference service, but is nonetheless an activity that JGN presently provides under the terms and conditions of the reference services agreements under the current AA to accommodate the administration of its network services in down-stream segments of the supply chain.

JGN has included these ancillary fees within the tariffs for the relevant reference service. This involves establishing a tariff charging parameter for each activity for which an ancillary fee is charged. These fees will continue to only be levied on users on an "as required" basis. Table 2-2 below sets out the reference services into which JGN has incorporated each ancillary activity.

Table 2-2: Incorporation of ancillary fees within reference services

Reference service	Incorporated ancillary fee
Haulage reference service	Request for service Temporary disconnection Permanent disconnection Decommissioning and meter removal
Meter data reference service	Special meter read

These groupings reflect the reference service to which the activity and charge is associated. They also reflect the fact that if meter data reference services became contestable during the AA period and therefore ceased being reference services, so too would special meter reading. JGN notes that until the meter data service becomes contestable, a request for a meter data service is deemed to have been made when a reference haulage service is requested[18].

JGN has reviewed the AER's draft decision which provides that these ancillary fees would need to be included as reference services because the AER has the view that these are pipeline services and that they are likely to be required by a significant part of the market. JGN's modification of its proposed reference services and the wording of the RSA provide a superior solution because it better recognises the circumstances in which users request the ancillary activities. It also reflects the fact that these are not pipeline services in their own right, but rather activities required from time to time to facilitate the delivery of pipeline services.

[18] Clause 17.1(b) of the Reference Service Agreement

2.4 JGN response to AER draft decision – legacy contracts

At the time that JGN developed its proposal, the commencement date for the STTM was uncertain. JGN's proposal therefore contemplated the possibility that transition from existing reference service contracts may occur after the AA revision commencement date. The transition mechanism proposed by JGN therefore included the concept of legacy services. The STTM is now set to commence on 4 June 2010 which is before the AA revision commencement date. In that case there will be no legacy services (as they are defined in existing contracts) being provided at the AA revision commencement date.

JGN considers that the technical and contractual features of legacy contracts, the services delivered under these contracts and the corresponding obligations these place on JGN and its users have not been fully understood. Such understanding is necessary in order to realise that these contracts cannot operate in an STTM context.

The AER's draft decision concluded that, in order for JGN to make the proposal acceptable to the AER, JGN should develop a legacy reference service to accommodate the continued provision of services currently delivered through legacy contracts as reference services. This is even though JGN's proposal is to simplify its reference services in a manner that accommodates the introduction of the STTM and provides market wide efficiencies through reduced levels of contract administration.

To explain further why JGN's legacy services should not continue as reference services, JGN provides the following detailed discussion of the relevant issues and explains why JGN has not revised its proposal to incorporate legacy contracts within its proposed reference services.

In essence, due to the planned introduction of the STTM prior to the AA revision commencement date, neither JGN nor users will be able to fulfil their obligations under the legacy contracts in the next AA period. As a consequence, these services should not be included as reference services in the next AA period and JGN has not revised its proposal in this regard.

Background and summary

Under its current AA and the corresponding Reference Services Agreement (RSA), JGN supplies the following haulage related services in addition to its meter data service:

- the local network capacity reservation service (**LNCRS**)

- the trunk capacity reservation service (**TCRS**)
- the local network managed capacity service (**LNMCS**)
- the trunk managed capacity service (**TMCS**)
- the local network throughput service (**LNTPS**)
- the trunk throughput service (**TTPS**)
- the local network tariff service (**LNTS**)
- the trunk tariff service (**TTS**).

For the next AA period, JGN's supply of these services will be affected by two related regulatory changes:

1. *introduction of the STTM* – Amendments to the National Gas Law[19] and the National Gas Rules[20] to provide for the commencement of the STTM for natural gas in the Sydney area on 4 June 2010.

2. *trunk reclassification* – Reclassification by the National Competition Council (**NCC**) of the Northern Trunk (Wilton to Newcastle) and Southern Trunk (Wilton to Wollongong) pipelines as distribution pipelines[21] under section 129 of the National Gas Law.

Each of these changes is discussed in detail later in this chapter. JGN discusses each of the services listed above and considers the impact of these two regulatory changes on the provision of each one. This discussion demonstrates that the legacy services as they are currently defined cannot be provided in the future. This is largely a result of the forthcoming introduction of the STTM, but also partly a result of the NCC's reclassification of trunk services.

The introduction of the STTM means that neither JGN nor users can identify specific receipt points through which gas enters the network. Under the STTM, scheduling and settlement of gas flows into the network will be done by the Australian Energy Market Operator (**AEMO**) at an aggregate level for the entire Sydney hub. This implies that users will be unable to nominate daily flows at particular receipt points, as required under contracts for reference services under

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19 *National Gas (South Australia) (Short Term Trading Market) Amendment Act 2009*.

20 The National Gas Rules are to be amended to include a new Part 20 (rules 363 – 497), under the *National Gas (Short Term Trading Market) Amendment Rules 2009*.

21 NCC, *Jemena Pipeline Reclassification – National Gas Law: Application by Jemena Gas Networks (NSW) Limited for Reclassification of the Northern Trunk and Southern Trunk Pipelines*, 29 June 2009.

the current AA. In addition, gas balancing (a key element of the legacy services) will no longer be done by JGN, since this function will also shift to AEMO with the introduction of the STTM.

The legacy services are therefore incompatible with the introduction of the STTM. Users (and similarly JGN) will not be in a position to fulfil their obligations under the current RSA and are therefore unlikely to seek ongoing supply of the legacy services following the introduction of the STTM. It follows that these services are unlikely to be sought by a significant part of the market in the next AA period and therefore should not be reference services.

2.4.2 The AER draft decision

In its draft decision the AER indicated that it considers that the legacy services discussed above should be reference services. The AER considers that "the legacy services are likely to be sought by a significant part of the market" and therefore should be considered reference services under the NGR rule 101.[22]

The AER does not propose to approve JGN's specification of legacy services and has required amendments to JGN's proposed AA to include legacy services as reference services and specify tariffs and other terms and conditions for the supply of these services.

2.4.3 JGN's response

JGN remains of the firm view that legacy services should not be reference services because these services as they are defined cannot be provided in a STTM environment and will not be sought by a significant part of the market during the next AA period.

Although these legacy services are currently widely used, this will not be the case after the introduction of the STTM and after 1 July 2010, for the following reasons:

- JGN will be unable to provide the legacy services as they are defined in current user contracts, since the point to point nature of legacy services makes them incompatible with market operation of the Sydney Hub under the STTM
- a set of replacement services which account for the STTM and other changes will be made available under the proposed AA.

The timing of the STTM commencement on 4 June 2010 has brought many of these issues to a head prior to implementation of JGN's revised AA. The

[22] Draft decision, p. 11.

transitional issues arising in the intervening period prior to 1 July 2010 have required a phasing out of legacy services. Due to the timing of STTM commencement, this can only be addressed commercially between JGN and its users ahead of the AA revision commencement. Considerations in determining the commercial approach will be to recognise that existing contracts are inconsistent with the STTM and that users will have the ability to move to new contracts (based on the new form of RSA) that are consistent with the STTM and the AA to apply in the next AA period from the start of the next AA period.

The following sections detail how this transition requirement arises and why legacy services are simply incompatible with the STTM and will not be sought by a significant part of the market.

Finally, JGN notes that the Standing Committee of Officials clarified the intended application of what are now rules 48(c) and 101 in the course of developing the NGR. The Australian Pipeline Industry Association had raised an issue in relation to clause 50(c) of the second exposure draft of the NGR as follows:

> The requirement for a service provider to describe all services that "are… sought by a significant part of the market" as reference services might inadvertently require service providers to offer currently contracted services as reference services. [23]

This is precisely the issue that concerns JGN. The SCO's response was:

> **Accepted -** The NGR requirements for the specification of reference services in access arrangements will return to a future-looking approach, where access arrangements must specify as reference services all services "that are likely to be sought by a significant part of the market." [24]

JGN has removed legacy services as a future concept in its revised AA. Consequently the previously proposed pricing premium is no longer relevant.

The legacy services

Under the current AA, JGN provides eight separate reference services, as set out in section 2.3.1 above.

These services involve transportation of gas through either the trunk or local network from a pre-defined receipt point to a delivery point. These are all point-to-point services requiring a pre-defined receipt point and delivery point. For the trunk services, the service agreement requires the user to nominate daily gas flows at each trunk receipt point in the Wilton section. This allows JGN to plan capacity of

[23] Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 9.

[24] Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 9.

gas flows at each receipt point and identify any users whose actual and nominated flows are out of balance. With respect to the TCRS, the current service agreement requires:

> Each Day, **and for each Receipt Point** at which the User receives Gas under this Agreement and any other agreement for the transportation of Gas between the Service Provider and the User, the User must provide the Service Provider with its forecast of withdrawals from the Network for each of the next three Days.

and

> The User must advise the Service Provider of the Quantity of Gas which the User intends to deliver or have delivered into the Network **at each Receipt Point** on the Nomination Day [emphasis added]

The agreement provides for transfer of custody over the gas at the receipt point at which it enters the network. The service agreement also requires (among other things) the user to ensure that gas delivered at each receipt point complies with quality standards.

A central element of all services is operational gas balancing. This is a process of correcting for differences between the aggregate of users daily nominated and actual gas flows, to ensure that an appropriate gas pressure level is maintained throughout the network. Gas balancing charges apply based on the amount of the aggregate imbalance for the day and the relative magnitude of each user's individual imbalance that contributed to the aggregate imbalance. The calculation of gas balancing charges is based on a comparison of actual withdrawals with nominated receipt point flows for each user.

Each pair of corresponding trunk and local network services is provided as a bundle in the Wilton network section. This means that a user taking a trunk service for transport from a trunk receipt point to a trunk exit zone must also take the corresponding local network service for transport from the exit zone to the delivery point.

Introduction of the STTM

The STTM is a wholesale market for trading natural gas at 'hub' points between transmission pipelines and distribution systems. The STTM is set to begin operation on 4 June 2010.

The STTM incorporates mechanisms for collecting demand and supply information and setting a daily market price for gas traded at a particular hub. The STTM hub relevant to the JGN network is the Sydney hub, which comprises four custody transfer points: Wilton; Horsley Park; Port Kembla; and Rosalind Park. On the day prior to the day of trading, market participants submit bids to purchase and offers to supply which are collated by AEMO. AEMO then sets a price for gas traded through the hub on the following day and issues a trading schedule. In the event that there is more or less gas traded through the hub than was scheduled, AEMO will rebalance the gas supply by procuring any excess or shortfall under market services designed specifically for this purpose.

The introduction of the STTM will affect the provision and acquisition of services on the JGN gas network in three ways:

- *no longer operationally balancing* – JGN will no longer be able to provide operational balancing of the Wilton section in its current form since all gas entering the Sydney hub will be allocated to users and AEMO will apportion charges arising from aggregate imbalances through MOS charges on users. Services under current balancing arrangements (where JGN procures and passes through the cost of balancing gas) are not relevant in the STTM design. Thus for all of the services listed above, JGN will no longer be able to perform one critical element of the service. Notably, the current service agreements do provide for review and variation of the gas balancing provisions in the event that JGN ceases to supply balancing gas (as will occur under the STTM). Therefore notionally, the legacy services could continue to be provided with a variation to exclude balancing. However for the reasons immediately below, even the terms of these varied legacy services could not be complied with by either JGN or users under the STTM.

- *no longer scheduling gas flows* – JGN will no longer be responsible for scheduling gas flows through its receipt points at the STTM hub (this will also be done by AEMO). Therefore JGN will lose visibility of where gas is entering the distribution network and will not be able to identify the receipt point used in any given case. JGN will no longer be able to provide services relying on the identification of a particular receipt point.

- *no longer nominating at receipt points* – Users of the gas distribution network will no longer be able to nominate receipts at specific hub receipt points. Under the STTM, users will acquire gas from broad market supply, rather than from a specific shipper at a specific receipt point. Users will only know the quantity of gas that is scheduled to enter the network for their use, not where that gas is entering or who is responsible for shipping it. This implies that users will be unable to fulfil their existing contractual obligations to nominate daily flows through specific receipt points.

The NCC reclassification of trunks

On 29 June 2009, the National Competition Council (**NCC**) determined that the Northern Trunk (Wilton to Newcastle) and Southern Trunk (Wilton to Wollongong) pipelines be reclassified as distribution pipelines.[25] As a result of this NCC determination, JGN does not provide services on a relevant gas transmission pipeline in the Sydney region.

Of particular relevance to the NCC's decision was the STTM. The NCC found that while historically the function performed by these pipelines were closer to that of a transmission pipeline, looking forward to the period of regulation that would be impacted by the reclassification of these pipelines—with the development of the STTM—the function is more like a distribution pipeline.[26]

The NCC's decision indicates that the provision of services on what were the "trunk" pipelines, and to the extent these services are linked to the provision of other services under the current AA—these services are of a fundamentally different nature following the reclassification of the trunk pipelines. Trunk services can no longer be distinguished from local network services and hence the provision of trunk services distinct from distribution services and the requirement for service bundling is unsustainable. An important issue in this context is the difference in pricing principles applying to trunk and local networks—if JGN were to distinguish between trunk and local network services, it would need to apply different principles to each segment under the NGR.

2.4.4 JGN's continued supply of the legacy services

Table 2-3 below shows that for each of the services listed above, at least two critical elements cannot be maintained following the introduction of the STTM. For all services, the provision of gas balancing will be precluded by the STTM, since this function will be carried out by AEMO. For trunk services, the identification of receipt points will also be prevented by the STTM, meaning that users will be unable to nominate flows through specific receipt points and JGN will be precluded from scheduling flows for these receipt points and identifying users whose nominated and actual flows are out of balance.

Separately to the introduction of the STTM, bundling of trunk and local network services will also be significantly affected by the NCC reclassification of trunk services.

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25 NCC, *Jemena Pipeline Reclassification – National Gas Law: Application by Jemena Gas Networks (NSW) Limited for Reclassification of the Northern Trunk and Southern Trunk Pipelines*, 29 June 2009.

26 NCC, *Jemena Pipeline Reclassification – National Gas Law: Application by Jemena Gas Networks (NSW) Limited for Reclassification of the Northern Trunk and Southern Trunk Pipelines*, 29 June 2009, [3.6].

Table 2-3: Jemena's ability to provide legacy services

Service	Delivery points	Receipt points	Balancing	Bundling
LNCRS	✓	✓	✗	✗
TCRS	✓	✗	✗	✗
LNMCS	✓	✓	✗	✗
TMCS	✓	✗	✗	✗
LNTPS	✓	✓	✗	✗
TTPS	✓	✗	✗	✗
LNTS	✓	✓	✗	✗
TTS	✓	✗	✗	✗

2.4.5 Will there be continuing demand for legacy services?

The changes associated with the introduction of the STTM imply that customers will no longer be able to acquire services in the Wilton section which require receipt point nomination. Nomination of receipt points is effectively a redundant activity under the STTM, since the scheduling of gas flows will be done by AEMO for the entire Sydney hub, rather than at the receipt point level. Since users will acquire gas from broad market supply rather than a single shipper, they will be unable to identify the network receipt point(s) for that gas. Given that the nomination of receipt points is incompatible with the STTM, this aspect of the legacy services is unlikely to be demanded following STTM commencement. In fact, users will be unable to take any service which requires them to nominate specific receipt points and even if this were possible, such a service could not be provided by JGN.

Additionally, JGN will not be required to provide balancing services under the STTM since this function will be carried out by AEMO. Even if it were possible for JGN to duplicate this function, this would give rise to unnecessary additional costs for no incremental benefit. This means that it will not be in the commercial interests of either JGN or its customers for JGN to continue to provide gas balancing as a service element. In other words, the market will no longer demand this aspect of JGN's services following implementation of the STTM.

The changes associated with the trunk reclassification mean that trunk services can no longer be distinguished from local network services and hence the concept of a trunk and local bundle is meaningless. It is therefore apparent that there will be no continuing demand for legacy services, insofar as they incorporate a requirement for bundling.

2.5 Amendments to the access arrangement proposal and information

JGN has amended its AA definitions for haulage reference service and meter data service to incorporate related ancillary fees and their terms and conditions.

3 Capital Base

This chapter is divided into two parts:

- Chapter 3a: Capital base – RAB, deals with the RAB and RAB roll-forward.
- Chapter 3b: Capital base – Forecast capital expenditure, deals with forecast capital expenditure.

3a Capital Base – RAB

- JGN has incorporated some of the amendments required by the AER in relation to JGN's capital base. JGN has incorporated the AER's view of how forecast depreciation should be deflated and re-inflated in the capital base roll-forward calculation.
- As a result, the combined total capital base at 1 July 2010 is now $2,357 million ($nominal) and forecast to be $3,069 million ($nominal) at 30 June 2015
- In its review of the AER's draft decision, JGN has identified two material errors in the AER's calculation of the capital base.
- JGN maintains its position that mine subsidence work is capital in nature, JGN has not excluded it from the historical capital expenditure that is rolled into its capital base. Neither has JGN removed the re-used redundant asset portion of the Wilton to Wollongong trunk. JGN has also not incorporated the AER's proposed change to the CPI indexation basis.

3a.1 Summary of JGN original AA proposal

JGN's original AA proposal set out how JGN proposed to roll-forward the capital base taking into account its capex, disposals and depreciation over the current and next AA periods.

JGN determined that the combined total of its capital base at 1 July 2010 is $2,367 million ($nominal) and is forecast to be $3,042 million ($nominal) at 30 June 2015. This was based on JGN's opening capital base in the current AA period adjusted for actual and forecast capex, capital contributions, depreciation and disposals as well as $3.44 million of reused redundant assets from the southern trunk required to accommodate the unconstrained design assumption of the STTM.

JGN also proposed the capital base be adjusted for inflation using the June quarter on June quarter CPI.

3a.2 Summary of AER draft decision

The AER draft decision provided that, in order to make the AA proposal acceptable to the AER, JGN would be required to make various amendments to the capital base, including:

- removing redundant capital on the Wilton to Wollongong pipeline from the 2010-11 opening capital base
- removing expenditure on mines subsidence from the opening capital base
- amending the mechanism used to adjust the capital base for inflation.

Table 3-1 sets out the amendments required by the AER in the draft decision.

Table 3-1: Amendments the AER required in its draft decision – opening asset base

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
3.1	Amend the AAI to use the year on year change in the four quarter average CPI to December to adjust the capital base for inflation.	Not incorporated	Section 3a.3.1
3.2	Amend the 2010-11 opening capital base in the AA to: incorporate the AER's proposed amendments to JGN's capital expenditure in the current AA period, including the removal of expenditure on mines subsidence; incorporate the AER's proposed amendments to depreciation in the current AA period; incorporate the AER's proposal to remove redundant capital on the Wilton to Wollongong pipeline from the opening capital base; and incorporate the AER's proposed amendments to the mechanism used to adjust the capital base for inflation.	Partially incorporated	Section 3a.3.1

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
3.3, 3.4, 3.5	Amend the projected capital base for the next AA period to incorporate the AER's proposed amendments to capex, forecast depreciation, forecast inflation and the opening capital base.	Not incorporated	Section 3a.3.5
3.6	Amend the AA to delete section 5 titled "Capital redundancy policy"	Not incorporated	Section 3a.3.6

The AER draft decision accepted JGN's proposed AA in relation to capital contributions (apart from contributions associated with mines subsidence expenditure) and disposals.

3a.3 JGN response to AER draft decision

This section addresses the matters raised by the AER in chapter 3 of the draft decision which deals with the calculation of the capital base. It also contains a discussion of errors that JGN has identified in the AER's capital base calculation and provides an adjusted capital base calculation.

In its review of the AER's draft decision, JGN has identified two material errors in the AER's calculation of the capital base. These errors, together with the AER's proposed exclusion of mines subsidence expenditure and change to the CPI indexation basis, result in the 2010-11 opening capital base in the draft decision being approximately $89 million less than the value proposed by JGN in its initial proposal (when expressed on a common basis).

JGN has incorporated some of the amendments required by the AER. As a result, the combined total opening capital base at 1 July 2010 is now $2,357.0 million ($nominal) and the forecast closing capital base at 30 June 2015 is $3,069.4 million ($nominal).

3a.3.1 Amendments to the capital base roll-forward calculation for the period 2005-06 to 2009-10 – amendments 3.1 and 3.2

JGN has not incorporated all of the changes to the capital base roll-forward calculation that are implicit in AER amendments 3.1 and 3.2.

Adjustment to capital base for inflation

JGN has not incorporated AER amendment 3.1, which requires JGN to adjust the basis for CPI indexation in the capital base roll-forward calculation.

In its August 2009 submission, JGN proposed using June quarter on June quarter CPI as the basis for CPI indexation in the capital base calculation. In its draft decision, the AER did not consider this method to be appropriate as the AER considered it inconsistent with the method used by JGN in its tariff variation mechanism in the current AA period. The AER considered that the basis for CPI indexation in the capital base calculation should be the same as that used for tariff variation. This approach would require JGN to apply the year on year change in the CPI to the December quarter to adjust the capital base. For the reasons set out below, JGN has not incorporated this amendment in its revised AA proposal.

The values of the capital base and new tariffs are determined as at 1 July each year and both are a function of CPI. In the interests of precision, JGN considers that the value of the CPI index should be determined at a time that is as close as practicable to the time at which the capital base or new tariffs are determined.

Once an AA has been approved, tariffs are varied in accordance with the approved tariff variation mechanism which is, in JGN's case at least, independent of changes in the value of the capital base during the AA period. Tariff verification proposals must be submitted to the regulator for approval some time before the tariffs are due to take effect and must be based on actual published CPI data. By using CPI data for the December quarter, as required by AER amendment 13.7, JGN can ensure that it has adequate time to prepare and submit a proposal for tariff variations that are to take effect in July.

The capital base value is not updated during the AA period. Rather, the capital base value is determined after the event in the capital base roll-forward calculation. At this time, a full suite of historical CPI values is available to support that calculation. Where the valuation is made at 1 July in any year, it is logical that the calculation be based on June quarter CPI data for that year.

There is no practical or theoretical reason why the indexing bases for the capital base roll-forward and tariff variation should be the same. Such an adjustment is not required in order to bring JGN's AA proposal into compliance with the NGR.

Calculation of forecast depreciation to be used in capital base roll-forward calculation

JGN has reviewed the reasons in the draft decision regarding the calculation of depreciation in the current AA period. Based on this review, JGN has incorporated the AER's view of how forecast depreciation should be deflated and re-inflated in the capital base roll-forward calculation.[27] JGN has deflated nominal forecast deprecation as approved by IPART using the forecast CPI values assumed by IPART, and reinflated those amounts using actual CPI values with the effect that

[27] Draft decision p. 42.

real deprecation in the roll-forward calculation is equal to forecast real depreciation as approved by IPART.

3a.3.2 Exclusion of mines subsidence expenditure

JGN has not incorporated the AER's draft decision regarding the treatment of expenditure on mines subsidence in the current AA period. The AER draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend its AA to remove the costs it incurred in repairing pipelines damaged by mines subsidence from the opening capital base. The AER relied on the findings of Wilson Cook to form the view that mines subsidence expenditure is not conforming capital expenditure under rule 79(1) of the NGR. Wilson Cook concluded that the expenditure "appears necessary" but that it should not be capitalised on the basis of a *presumption* that no new assets were created and neither was the life of an existing asset extended[28]. This finding was accepted by the AER which concluded that:

> the costs of repairs to pipelines damaged by mines subsidence are expenses, not capital expenditure. As outlined in the Wilson Cook report this is because the nature of the expenditure does not either create an asset or extend the life of an existing asset to justify that the amount of expenditure can be added to the capital base.[29]

As a result, the AER draft decision requires JGN to remove mine subsidence and its associated capital contributions from the opening capital base. The net effect is a reduction in the capital base of $4.6 million ($2004-05).[30] The AER takes the view that this loss is offset by the amount JGN underspent for marketing opex in the current AA period.[31]

Capitalisation of JGN's mines subsidence expenditure is consistent with JGN's capitalisation policy. In this regard, JGN notes that the Wilson Cook report explicitly states that a review of the business's policies for the capitalisation of expenditure was 'excluded from consideration in our work, or [was] not undertaken'.[32] It is not clear how the AER can rely on Wilson Cook's conclusion that these costs are not capital in nature when such analysis was not part of the consultant's scope of work. JGN confirms that its policy is to capitalise mines subsidence costs in its audited statutory accounts.

JGN considers that its expenditure on mines subsidence is capital in nature and therefore should be included in the opening capital base. In this regard, JGN notes

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28 Wilson Cook report, p. 45.

29 Draft decision, p. 37.

30 Draft decision, p. 37.

31 ibid.

32 Wilson Cook report, p. 3.

that IPART accepted its proposal to capitalise mines subsidence expenditure in the two preceding AA periods and did not include mines subsidence within the scope of JGN's operating expenditure allowance.

JGN further submits that the expenditure on mines subsidence will ensure that damage as a result of mines subsidence is eliminated as a risk factor for the pipeline. Without the expenditure, there is a very high risk that a pipeline rupture would occur at some time in the future with severe consequences for the provision of services, for public safety and for the pipeline assets themselves. Alternatively the pipeline could become so unsafe that some or all of it would have to be replaced prematurely. In that sense the expenditure has the effect of extending the life of the pipeline. It is the most economical means of mitigating the risk and will not be a recurrent expenditure. It is prophylactic in nature and has enduring value for the remaining life of the pipeline. In light of the above, JGN submits that expenditure on mines subsidence during the current AA period should be treated as capital in nature and therefore included in its opening capital base. In this regard, JGN reiterates the submissions made in its August 2009 proposal that its mines subsidence expenditure is conforming capital expenditure within the terms of Rule 79(2)(c) of the NGR.

Despite JGN's reliance in its August 2009 proposal on rule 79(2)(c) of the NGR to claim mines subsidence expenditure as conforming capex[33] and IPART's previous approval of this expenditure as conforming capital under the equivalent Gas Code test[34], neither Wilson Cook nor the AER directly addressed the rule 79(2)(c) criteria:

> 79(2)(c) the capital expenditure is necessary:
>
> (i) to maintain and improve the safety of services ; or
>
> (ii) to maintain the integrity of services

However, Wilson Cook's statement that the expenditure appears necessary and the AER's acceptance that the costs are expenses could be interpreted as an acknowledgement that the test is met. The remaining question to be addressed would then be whether the expenditure is capital in nature, or is an operating expense. For the reasons set out above, JGN considers that its expenditure on mines subsidence is capital in nature.

As a result, JGN considers that its treatment of mines subsidence expenditure, net of related capital contributions, as conforming capital expenditure is correct. Failing that, future net expenditure on mines subsidence should be allowed as

33 JGN, *Access Arrangement Information*, 26 August 2009, p. 114.

34 Clause 8.16(a) of *National Third Party Access Code for Natural Gas Pipeline Systems*, 1997.

O&M expenditure, consistent with the AER's acceptance that the costs are expenses.

Accordingly, JGN has retained historical mine subsidence expenditure in the capital base roll-forward calculation.

3a.3.3 Errors in the draft decision capital base roll-forward calculation

JGN believes that the AER has made two significant errors in its capital base roll-forward calculation as provided to JGN.[35] JGN has not incorporated the changes required by amendment 3.2 to the extent that they are a consequence of those errors.

Converting forecast capex and capital contributions between nominal and real dollars

JGN believes that the AER has made an error in converting forecast capex and capital contributions between nominal and real dollars.

In the calculation that underpins the draft decision, the AER performs the capital base roll-forward calculation in real dollars and then converts the result to nominal dollars for presentation in the draft decision. This is the same approach that JGN adopted in its August 2009 proposal. In order to perform that calculation, the values of capex and capital contributions that are incurred in nominal dollars are converted to real dollars.

In its calculation the AER appears to have incorrectly deflated nominal capex and capital contribution values using JGN's assumed inflation values, and then reinflated the resultant "real" values using the AER's assumed inflation values to produce a different set of "nominal" capex values. The implication is that nominal historic capex and capital contributions are a function of the assumed inflation basis. This result cannot be justified given that capex and capital contributions are incurred and reported in nominal dollars. Capex and capital contributions must be deflated and reinflated using the same inflation basis.

The effect of this error on the 2009-10 closing capital base value calculated by the AER is $27 million. That is, the closing capital base for 2009-10 calculated by the AER would increase from $2,277.9 million to $2,304.9 million.

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[35]" JGN asset base roll-forward.xls" model, the AER provided this model to JGN on 9 February 2010.

Interpreting the nominal 2005-06 capital base opening value and Wilton to Wollongong trunk redundancy amount

JGN also believes that the AER has made an error in interpreting the nominal 2005-06 capital base opening value and the Wilton to Wollongong trunk redundancy amount.

The AER's nominal capital base roll-forward calculation applies escalation between the end of one year and the beginning of the next.[36] As a result, there is a discontinuity between the closing value for one year and the opening value for the next and all dollar values reported for a year are implicitly "end of year" values.

The structure of JGN's nominal representation is the same as that adopted by IPART. Inflation is applied within each year as "revaluation of assets" so that, correctly interpreted, the opening value for a year is in beginning of year dollars and the closing value (and other values for the year) are in end of year dollars.[37] The result is that the real value of the RAB is maintained[38] while at the same time avoiding discontinuities between years.

In accordance with this logic, the nominal 2005-06 opening capital base submitted by JGN in August 2009 ($1,965.5 million) is in 2005-06 beginning of year dollars which are the same as 2004-05 end of year dollars. The 2005-06 opening capital base as submitted by JGN is also the same as the 2004-05 closing capital base determined by IPART after removal of the $2.1 million Wilton to Wollongong trunk redundancy amount.[39] That is, the opening balance in Table 8-4 in JGN's August 2009 proposal reconciles to the closing balance in IPART's final decision.[40] That amount is denoted by IPART as being in [2004-05] nominal dollars.[41]

In its deflation calculation, the AER has deflated all 2005-06 values, including JGN's 2005-06 opening value and the Wilton to Wollongong trunk redundancy amount, with the objective of converting those values to 2004-05 values. This approach is appropriate for all values except for the opening value and Wilton to

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36 bid.

37 JGN acknowledges that, with this structure, it is somewhat inaccurate to denote all amounts as "$nominal" in relevant tables. Opening values and half of the real equivalent of the capex for a year are in fact $nominal as at the end of the preceding year. See AER, *2010 03 11 – Letter AER to JGN – Errors in draft decision*, 11 March, 2010, Item 2 under the heading 'Errors in AER's draft decision document (3 March 2010, 6 page letter)'.

38 See AER, *2010 03 11 – Letter AER to JGN – Errors in draft decision*, 11 March, 2010, Item 3 under the heading 'Errors in AER's draft decision document (3 March 2010, 6 page letter)'; and Item 3 under the heading 'Clarification of AER's reasons for draft decision: (8 March 2010, 3 page letter)'.

39 IPART, *Revised Access Arrangement for AGL Gas Networks, Final Decision*, April 2005, p. 87.

40 See AER, *2010 03 11 – Letter AER to JGN – Errors in draft decision*, 11 March, 2010, Items 1-3 under the heading 'Errors in Jemena's access arrangement proposal (3 March 2010, 9 page letter)'.

41 IPART, *Revised Access Arrangement for AGL Gas Networks, Final Decision*, April 2005, Table 7.10, p. 87 and Table 7.14, p. 88.

Wollongong trunk redundancy amount because, as explained above, the opening value for 2005-06 and the Wilton to Wollongong trunk redundancy amount in JGN's nominal representation are already in 2004-05 end of year dollars. Accordingly, it is unnecessary and inappropriate to deflate the opening value and Wilton to Wollongong trunk redundancy amount as the AER has done.

The effect of correcting this error on the 2009-10 closing capital base value as calculated by the AER is to increase that value by $61.4 million. Correcting this error, and the error in converting forecast capex and capital contributions between nominal and real dollars, together would add $88.4 million to the 2009-10 closing capital base calculated by the AER. That is, the closing capital base for 2009-10 calculated by the AER would increase from $2,277.9 million to $[2,366.3] million.

3a.3.4 Allowing for the fact that capital is spent throughout the year

The AER and JGN have also adopted different approaches to making allowance for the fact that capital is spent throughout the year. In its roll-forward calculation for the current AA period, the AER has made the allowance by uplifting capex by half a year's WACC in the real calculation. JGN, on the other hand, has used the approach adopted by IPART which is to assume that half the year's capex is spent at the beginning of the year and half at the end of the year in the nominal calculation. JGN has used this approach for both the current regulatory period roll-forward to 2009-10 and the projected capital base for the next regulatory period to 2014-15.

In its draft decision the AER has not questioned the approach that JGN has taken to this aspect of the projected capital base calculation. In any event, the AER's discretion to vary the approach is limited to the extent that it flows through to the calculation of depreciation[42]. It would be inconsistent to adopt different approaches for the current period roll-forward and projected capital base calculations.

3a.3.5 Amendments to the projected capital base calculation for the period 2010-11 to 2014-15 – amendments 3.3, 3.4 and 3.5

JGN has not incorporated the changes to the projected capital base calculation that are implicit in AER amendments 3.3, 3.4 and 3.5. JGN provides reasons for its position in relation to the forecast capex and depreciation aspects of the calculation in chapters 3b and 4 of this submission. The revised projected capital base calculation reflects the position that JGN has taken on forecast capex and depreciation and on the treatment of redundant capital on the Wilton to Wollongong trunk.

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[42] National gas rules, rule 89(3).

Redundant capital on the Wilton to Wollongong trunk

JGN has not incorporated the AER's amendment to remove from the 2010-11 opening capital base the value of the $3.44 million ($nominal) redundant capital on the Wilton to Wollongong pipeline as a re-used redundant asset.

The STTM is expected to commence in June 2010. The design of the market calls for the Sydney, Newcastle, Wollongong and Central Coast sections of the JGN network to be treated as single hub. The Wilton to Wollongong trunk is within the hub.

JGN's proposal to dispense with separate trunk and network tariffs and establish a single set of network tariffs for the hub sections (the coastal zone) is consistent with and justified on the basis of the STTM design. By accepting the tariff structures proposed by JGN, the AER has apparently accepted this proposition.

The AER does not accept JGN's proposal to reinstate the value of the Wilton to Wollongong trunk that IPART found to be redundant:

> The AER considers that Jemena's access arrangement proposal does not contain evidence that demand on the redundant asset has increased during the [current] access arrangement period. In addition, Jemena's demand forecasts for the [next] access arrangement period do not support an increase in usage of this pipeline in [that] access arrangement period.[43]

In taking this position, the AER appears to have misunderstood the operation and requirements of the STTM.

Under existing arrangements where users contract for transportation between specified receipt points and delivery points, JGN knows and can control the demand for services on and utilisation of the Wilton to Wollongong trunk. Under the STTM, JGN will lose that control. Utilisation of the Wilton to Wollongong trunk will be determined by the market on a day to day basis. As a consequence, it is no longer feasible to forecast utilisation in the way that it has been forecast in the past or as contemplated by the AER. It is not difficult to envisage situations where the STTM could demand and utilise the full physical capacity of the Wilton to Wollongong trunk.

One of the key requirements of the hub design is that there should be no significant constraints within the hub:

> The proposed market will use network Hubs. The key requirements for the Hubs are that pricing is uniform across the Hub and that there are no significant capacity constraints within the Hub. The capacity constraint requirement is to make sure that

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43 Draft decision, p. 43.

> any gas scheduled in the STTM to the Hub through offers or scheduled from the Hub through bids is not constrained from flowing during the gas day. This would put shippers and users at risk for Deviations and create potential gas pipeline and distribution security situations. It would also effectively create non-uniform marginal value of gas within the Hub.[44]

and

> The aim of the STTM is to create an efficient trading hub. The hub should not have material and enduring pipeline constraints. If there were material and enduring pipeline constraints then this could lead to the need for changes to the STTM design.[45]

Imposing an artificial (economic) constraint on the capacity of the Wilton to Wollongong trunk will mean that its operating capacity is less than its physical capacity. That would be contrary to design requirements for the STTM.

JGN maintains that the stranded value of the Wilton to Wollongong trunk should be reinstated to the RAB as a re-used redundant asset.

3a.3.6 Capital redundancy policy – amendment 3.6

JGN has not incorporated amendment 3.6 which requires JGN to delete its proposed capital redundancy policy from the proposed AA.

The capital redundancy policy proposed by JGN in August 2009 started with the words "The AER may reduce the capital base …". The AER considered this wording to be inconsistent with rule 77(2)(e) of the NGR:

> Jemena proposes a redundancy policy that gives the AER the discretion to remove the value of redundant assets from the opening capital base. The AER considers that under r. 77(2)(e) of the NGR there is no discretion and redundant assets must be removed when determining the opening capital base for an access arrangement period. In light of this, the AER considers that Jemena's proposed capital redundancy is likely to cause uncertainty for users and prospective users.[46]

As a result, the AER required JGN to delete the capital redundancy policy in section 5 of its AA proposal.

Rule 85 provides that a full AA may include a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services are removed

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44 ICF International, A Proposed Design for the Natural Gas Short Term Trading Market for Australia, prepared for Gas Market Leaders Group, 24 December, 2007, p. 24.

45 Geoffrey Swier, *Application by Jemena Gas Networks to the National Competition Council for Reclassification of Transmission Assets*, Independent Expert Report, 17 April 2009, p. 3.

46 Draft decision, p. 71.

from the capital base. JGN has proposed such a mechanism. In order to address the AER's concern that the mechanism as proposed introduces discretion contrary to the rules, JGN has revised paragraph (a) of its capital redundancy policy as follows:

> (a) In accordance with Rule 77(2)(e) and (f), redundant assets identified during the course of an access arrangement period and pipeline assets disposed of during that access arrangement period, will be removed from the opening Capital Base with effect from the commencement of the following access arrangement period.

JGN considers that, with this change, the capital redundancy mechanism is consistent with the requirements of the NGR. The mechanism provides for the removal from the capital base of assets that cease to contribute to the delivery of pipeline services. The mechanism proposed by JGN does not give rise to any uncertainty, and therefore, does not have an effect on JGN, users or prospective users that may be relevant under rule 85(4). As JGN's proposed capital redundancy mechanism is consistent with the requirements of the NGR, it is not open to the AER to not approve JGN's revisions.

3a.4 Amendments to the access arrangement proposal and information

Following its review of the AER's draft decision, JGN has retained its proposed capital base roll-forward calculation with the following amendments:

- JGN has deflated nominal forecast depreciation as approved by IPART using the forecast CPI values assumed by IPART, and reinflated those amounts using actual CPI values with the effect that real deprecation in the roll-forward calculation is equal to forecast real depreciation as approved by IPART.

- To the extent that the 2005-06 opening capital base value approved by IPART was based on forecast inflation, deflated the value using the forecast CPI value assumed by IPART, and reinflated the resultant value using actual CPI values.

- Brought calculations previously performed within the escalation models into the capital base roll-forward calculation so that revaluation and depreciation amounts are calculated on a consistent basis in all years.

- Updated the 2010-11 to 2014-15 projected capital base calculation for revised forecasts of capex, capital contributions, depreciation and disposals over the period.

Table 3-2 shows JGN's adjusted 2009-10 and 2014-15 closing capital base values compared with corresponding values from JGN's original AA proposal and the AER's draft decision.

Table 3-2: Comparison of Capital Base values ($nominal)

	Closing 2009-10	Closing 2014-15
JGN August 2009 proposal	2,366.9	3,041.5
AER Draft Decision	2,277.9	2,638.9
JGN adjusted proposal	2,357.0	3,069.4

The RAB is now dealt with in section 7 of JGN's revised AAI. All tables in section 7 except Table 7-3 are affected by the changes described above.

3b Capital Base – Forecast capital expenditure

- JGN's revised capex forecast of $891 million reflects detailed costings for near term projects that have further progressed through the capex gating process since JGN's original proposal was submitted to the AER and updated escalators and demand forecasts.
- JGN's forecast capex involves a significant increase relative to current period spend due to increased investment in system reinforcement to manage capacity constraints caused by use of existing capacity. There is also significant investment in the refurbishment and replacement of facilities which are reaching the end of their life, growth in market expansion (new connections), significant system reinforcement and renewals requirements and required IT catch-up. The draft decision capex allowance is insufficient to meet these needs, even if an extreme assumption of no real change in unit costs between the periods is made.
- The AER and Wilson Cook have formed a view that certain forecast capex projects are not of a capital nature and proposed to exclude these activities and projects from forecast capex. This is not consistent with the application of JGN's capitalisation policy which has been reviewed by an expert accountant and found to be compliant with the relevant accounting standards and good industry practice.

3b.1 Summary of JGN's original proposal

JGN's original proposal forecast capex of $885.2 million over the next AA period. This forecast was based on JGN's Asset Management Plan (**AMP**) and Information Technology Plan (**ITP**). It provides for a capital works program that enables JGN's network and IT to operate at an acceptable level of risk including:

- ongoing renewal and upgrade of mains and services, addressing priority areas with high leakage rates and maintaining capacity constraints asset safety and reliability at current levels
- capacity development to manage demand growth with system average interruption duration index (**SAIDI**) and customer hours off supply (**CHOS**) maintained at current levels or lower
- renewal and upgrade of ageing facilities considering upstream operating pressure upgrades, standardisation, OH&S risks, spares and inventory

control, capacity constraints, integrity and compliance with technical regulatory requirements

- a robust IT program that supports business and market requirements and optimises IT opex.

3b.2 Summary of AER draft decision

The AER draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the AA proposal with regard to its forecast capex.

In rejecting JGN's proposed capital expenditure for the next access arrangement period, the AER:

- *Wilson Cook report* – relied on the views of its consultant Wilson Cook & Co (**Wilson Cook**) as expressed in its report: Wilson Cook & Co, *Review of Expenditure of ACT & NSW Gas Distributors, Jemena Gas Networks (NSW) Ltd*, December 2009 (**Wilson Cook report**), in particular that:
  - JGN's proposed capital program for the next AA period is reasonable in scope and timing for market expansion; system reinforcement, renewal and replacement; and non-system assets[47]
  - the information JGN had provided was insufficient to enable it to attest the cost efficiency of the forecast expenditure[48]
  - some level of overhead recovery or margin may be payable but JGN has not provided adequate information to determine it[49]
  - benchmarking costs is not a valid means of demonstrating cost efficiency because "benchmarking is best presented as an accompaniment to other substantiating analyses such as a "bottom-up" analysis of operating costs"[50]
  - that mine subsidence, ad hoc mains and service renewals, and pigging and integrity dig expenditure is necessary but not 'capital in nature' because Wilson Cook presumes these do not create a new

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47 Wilson Cook report, p. 20.

48 Wilson Cook report, pp. 70-71 and draft decision, pp. 48 and 51-54.

49 Wilson Cook report, pp. 70-71 and draft decision, pp. 48.

50 Wilson Cook report, p. 48 and draft decision, pp. 69-70.

asset or extend the life of an existing asset or is not incurred to provide, or in providing, pipeline services.[51]

- *gating process* – discounted the JGN/JAM capital approval, gating and contractor management process as a means of JGN obtaining efficient cost estimates for capital projects for its forecasts[52]

- *ability to deliver* – considered historical expenditure to be a good indication of the level JGN is capable of delivering in the next AA period[53]

- *JGN forecast not compliant* – concluded that JGN's forecast capital expenditure for the next AA period does not comply with the requirements of rule 79 of the NGR[54]

- *market expansion forecast* – required JGN to adopt in its AA revision the following replacement forecast:

  – JGN's forecast cost less the margin and overhead recovery components payable to JAM

- *system reinforcement, renewal and replacement forecast* – required JGN to adopt in its AA revision the following replacement forecasts:

  – a baseline level of expenditure based on historical levels of capital expenditure for the work, except the following two variations:

    – make no forecast allowance for mine subsidence work, ad hoc mains and service renewals, and pigging and integrity dig expenditure—and make no corresponding opex allowance for mine subsidence work[55]

    – add back JGN's forecast cost for the Wakehurst Parkway, Smithfield to Liverpool and Tempe PRS projects less the margin and overhead recovery components payable to JAM[56]

- *non-system forecast* – required JGN to adopt in its AA revision the following replacement forecasts:

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51 Wilson Cook report, p. 48 and draft decision, pp. 53.

52 Draft decision, p. 52

53 Draft decision, pp. 52-3.

54 Draft decision, p. 45.

55 Draft decision, p. 53.

56 Draft decision, p. 53-4.

- a baseline level of expenditure based on historical levels of capital expenditure for all work, except those two groups listed below

- JGN's forecast cost for land buildings and leasehold less the cost of workstations, and less the margin and overhead recovery components payable to JAM

- JGN's forecast cost for IT less the cost of a contingency sum, organic growth infrastructure, and market changes and access arrangement IT implementation costs, and less the margin and overhead recovery components payable to JAM[57]

- *silent on compliance* – the AER did not analyse its substituted capital expenditure forecast or determine that it complies with the requirements of rule 79 of the NGR.

Inflation and cost escalator forecasts

In relation to inflation, the AER:

- *JGN's not best estimate* – concluded that JGN's forecast inflation rate of 2.38 per cent for the next AA period did not represent the best forecast possible in the circumstances[58]

- *substituted estimate* – considered that a geometric average comprising the RBA's short-term inflation forecasts and the target range mid-point of 2.5 per cent should be used to forecast the inflation rate, giving a forecast inflation rate of 2.47 per cent which represents JGN's proposed method lagged by one year and updated for more recent RBA data.[59]

In relation to cost escalators, the AER:

- *calendar years* – erroneously rejected JGN's proposal that cost escalators for capital expenditure be based on calendar years (when JGN had in fact used financial year escalators for both opex and capex) and instead proposed that the escalators be determined on the basis of financial years;[60]

- *labour cost* – asserted that, since the determination of the labour cost escalators proposed by CEG (and adopted by JGN), there have been

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57 Draft decision, p. 58.

58 Draft decision, p. 69 and Chapter 5.

59 Draft decision, p. 69 and Chapter 5.

60 Draft decision, p. 60.

significant changes in the economic outlook as well as fluctuations in some relevant economic data without referencing or providing this data

- *materials cost* – rejected JGN's (opex) proposal that a general materials cost escalator (calculated as a simple average of the escalators for aluminium, steel, polyethylene and concrete) be applied to all materials related capital expenditure [61]

- *carbon* costs – rejected JGN's proposal that an additional escalator be applied to its forecast capital expenditure to account for the effect of a Carbon Pollution Reduction Scheme (**CPRS**)[62].

Required amendment

Table 3-3 sets out the amendments that the AER stated would be required in order to make the proposal acceptable to the AER in relation to its opening asset base.

Table 3-3: Amendments the AER required in its draft decision – opening asset base

AER required amendment		JGN revised AA proposal	Explanation in this document
No.	**Description**		
3.3	Amend the AA to update its projected capital base for the next AA period to reflect amendments 3.3 to 3.6 relating to proposed capital expenditure, forecast depreciation, adjustment for inflation and adjustment of the opening capital base.	Not incorporated	Section 3b.3

3b.3 JGN response to AER draft decision – forecast capex

3b.3.1 Overview of JGN capex forecasting

JGN forecasts and manages its capex projects through a comprehensive planning, design, estimating and staged approvals process (**the gating process**). This gating process has been confirmed by Parsons Brinckerhoff as consistent with the efficient and prudent delivery of capex and reflective of good industry practice. The process also supports the refinement of project cost estimates as they progress to delivery stage.

61 Draft decision, p. 62.

62 Draft decision, pp. 65-6.

The gating process is such that, the closer a project is to final approval and delivery, the greater the amount of information available and the more certain the cost estimate.

JGN now has available more detailed project designs and cost estimates

In the time between submitting JGN's original AA proposal and this draft decision response, a number of projects have progressed within the gating process. As a result, more information, including more accurate costing information and business cases are now available for a number of JGN's proposed capital projects. JGN has provided a confidential sample set of these businesses cases in appendix 3b.12.

Using the information now available, JGN has updated its AA to include more accurate and up-to-date capex forecasts. These forecasts are compliant with JGN's capitalisation policy, which has been the subject of an independent review by Ernst & Young.

As a result of updated information JGN's revised AAI incorporates forecast capex of $891 million for the next AA period.

JGN has updated its capex forecast and elaborated on how these are developed

This section sets out JGN's revised capex forecasts and addresses the matters raised by the AER in its draft decision. These revised estimates and forecasts are discussed in greater detail below and provide the level of information the AER requires to assess JGN's forecast capex as it now stands. As part of a process by which JGN has been seeking clarification of the AER's requirements, on 10 March 2010, the AER requested some sample documentation that JGN provides with this submission. JGN would be pleased to provide any further information on the basis of this interaction.

JGN considers that its revised forecast capex is 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. Further, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

One reason that JGN considers its costs reflect lowest sustainable cost is the outsourcing of its asset planning, design and construction activities to JAM. JGN's AMA with JAM enables it to access the benefits associated with the scale and scope of JAM's operations and the significant intellectual property that JAM has as one of Australia's leading and largest asset management firms. In turn JGN pays JAM a commercial margin on all capital works which compensates JAM for the opportunity cost and risk of servicing JGN rather than other possible clients. It is unreasonable to presume that JGN could access these benefits through JAM or another external provider without paying a commercial return. Section 9.3.3 explains these arrangements and their benefits in more detail.

Consequently, JGN has not incorporated AER amendment 3.3. Rather, JGN has replaced the items referred to in these amendments with a forecast that reflects prudent and efficient capex.

The remainder of this section:

- examines the factors necessitating increased capex in the next AA period relative to the current period
- provides JGN's revised capex forecast and reconciles this to the original proposal
- explains JGN's capital plan and its gating and approval process as applied to routine and non-routine capex within which JGN develops its stay in business capex forecasts and delivers the related capex program
- explains the capex forecasting, governance and delivery process for system expansion and non-system capex
- discusses the project gating status of key capex projects including major projects that have progressed through detailed design and estimate refinement since JGN submitted its original proposal

3b.3.2 Factors influencing JGN's capex

JGN's current acceptable network safety and reliability performance is under threat as a result of a number of significant external factors. It is these factors that are driving JGN's increase in capex projects compared to the current AA period.

Peak capacity limitations

As previously advised JGN experienced lower demand in the current AA period than forecast by IPART which enabled JGN to delay certain capacity projects and implement short term capacity extensions. These temporary capacity extensions have now been exhausted and it is not possible to defer projects further. As a result, a number of critical system reinforcement projects are now necessary to manage system peak demand.

Modelling, gauging and analysis have allowed just in time capital investment to manage network demands to be accommodated. This approach has utilised existing system capacity created as a result of JGN's Goldline project in the 1990s to delay significant capacity reinforcement. This approach has also created a requirement for a number of critical system reinforcements to manage system peak demand driven by customer growth and changing gas appliance technologies including the increased use of high capacity instantaneous hot water systems. New appliances generally have peak load requirements up to 10 time greater than traditional units yet consume up to 40% less on an annual basis.

The capacity enhancements identified in JGN's capital program are critical in preventing loss of supply incidents for large customers which could result from the forecast demand in a 1 in 20 cold winter event.

In some cases, such as the Wakehurst Parkway project, modelling indicates that if the project is not undertaken, a one in two winter event could result in up to 3,000 customers losing supply. Such a supply reliability risk is unacceptable to JGN and inconsistent with the Nation Gas Objective.

Modelling and analysis has indicated that unless these planned projects proceed there is a potential for loss of supply of greater than 6,000 customers in various regions of the network. The existing design and construction of the network means there are limited alternate solutions that can be implemented to mitigate this risk.

Replacement of original high pressure Natural Gas supply systems

The majority of JGN's high pressure system assets were constructed and commissioned as part of the introduction of natural gas to NSW in the late 1960s and early 1970s. A significant proportion of these assets are now reaching, and in some cases have exceeded, the end of their usable lives. Many of these assets were constructed 40 years ago utilising historic standards of the day. Any significant activity to replaced failed key components at these sites will generally require the upgrade of significant elements of the site to meet today's standards. Assessment of these facilities has found that to maintain integrity and meet prudent engineering practice it is more cost effective to upgrade the total facility or facilities rather than repair and upgrade on a piecemeal basis. This is consistent with the lowest total life-cycle cost.

Metering Accuracy Standard

Metering assets are forecast to be replaced to meet the new regulatory and metering standard requirements. The new metering accuracy standard almost eliminates the likelihood residential meter life extensions beyond 20 years. Analysis has been completed to determine the most cost effective method of meeting the requirements given the age and performance of the assets and their impact on revenue and UAG.

APA Pipeline pressure increase

APA Group have informed JGN that they will be increasing pressures on the Southern NSW high pressure pipeline system. This necessitates the upgrading of

13 country Package Off Take Stations in order to maintain the safety, integrity, functionality of the JGN network

3b.3.3 JGN revised capex forecast

Table 3-4 reconciles JGN's revised forecast capex with the capex proposed in its original AA proposal.

Table 3-4: JGN forecast capex

Market Expansion	2010-11	2011-12	2012-13	2013-14	2014-15	Total
August 2009 Submission	64.7	75.6	80.7	76.8	73.2	371.0
March 2009 Response	61.2	73.1	75.0	88.3	96.7	394.5
Difference (percent)	-3.5	-2.4	-5.7	11.5	23.5	23.4
System reinforcement/ renewal/ replacement	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**Total**
August 2009 Submission	82.7	71.4	69.0	69.9	88.0	381.0
March 2009 Response	80.6	78.4	73.8	65.5	70.1	368.5
Difference (percent)	-2.0	7.0	4.8	-4.4	-17.9	-12.5
Non System Assets	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**Total**
August 2009 Submission	25.7	20.1	18.1	34.2	35.0	133.2
March 2009 Response	24.4	18.2	16.7	33.9	34.9	128.1
Difference (percent)	-1.4	-1.9	-1.4	-0.3	-0.1	-5.1
Total	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**Total**
August 2009 Submission	173.1	167.1	167.8	181.0	196.2	885.2
March 2009 Response	166.2	169.8	165.5	187.7	201.8	891.0
Difference (percent)	-6.8	2.6	-2.3	6.8	5.6	5.8

Cost estimating in the forecast

JGN and JAM employ the gating process to ensure efficient costing and delivery methods for projects that have been approved by JGN prior to the release of funding for project delivery.

JGN's budget cost estimate for forecast capex are derived from detailed cost estimating models. The budget estimate is built up based on internal costs, contractors, construction and detailed design if complex, materials and restoration.

As discussed below JAM competitively tenders for construction and detailed design for all projects related to system reinforcement, renewal and replacement capex and market expansion capex.

The cost results from the tenders for these projects are then used to forecast the cost for construction and detailed design of similar projects at the budget cost estimate and feasibility cost estimate stages. This is discussed further below.

Napier & Blakeley (appendix 3b.2) have reviewed JAM's cost estimating model for routine capex projects against the industry standards outlined in the Australian Cost Management Manual produced by the Australian Institute of Quantity Surveyors. They found that the estimating procedures followed by JAM are consistent with accepted industry accepted standards.[63]

Parsons Brinckerhoff (appendix 3b.1) have reviewed the planning, estimating and approvals process for non-routine capex and concluded that this process results in forecast estimates for the projects reviewed represent efficient values and are compliant with rule 74.[64]

These processes are discussed in the following sections.

3b.3.4 Capital Plan

The starting point for all capital expenditure on the JGN network is the Asset Management Plan (**AMP**). The AMP details the current and proposed strategies for the effective management of the network. The AMP is a holistic, whole of life management strategy for the JGN network.

One component of the AMP is the capital plan. The capital plan is a five year view of what projects need to be done in order for the network to meet forecast customer demand and a changing utilisation profile, and achieve the safety and performance objectives set out in the AMP.

The AMP allows JGN to identify areas requiring capex to expand, maintain or repair the network. JGN then considers various options for addressing those needs. Each option is given a budget cost estimate. The most cost efficient and effective option is then proposed for the capital plan.

Once a year, JGN either approves or rejects the inclusion of each project in the capital plan as part of its review of the AMP.

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[63] Napier Blakeley, Jemena Gas Networks (NSW) Access Arrangements 2010: Expert Terms of Reference – CAPEX Review, March 2010 , p2

[64] Parsons Brinckerhoff, Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision, March 2010, p vii

If the project is a system reinforcement, renewal, replacement or growth capacity development project, is also subject to the project gating process outlined below.

3b.3.5 Gating process for System reinforcement, renewal, replacement

The draft decision expressed concern with the cost efficiency of JGN's system reinforcement, renewal and replacement forecast capex. In response to these concerns, JGN commissioned experts – Parsons Brinckerhoff (**PB**) and Napier & Blakeley – to review the operation of JGN's gating process and determine whether it is consistent with the requirements of rule 74 in terms of providing a reasonable basis for cost estimating and can be expected to result in cost forecasts consistent with the requirements of rule 79. The results of this review are set out below.

JAM uses the gating process to assess all projects undertaken on JGN's network. It also uses the same or equivalent processes for delivering capital works to other clients.

PB confirms the opinion expressed in their August 2009 Report (which was provided as Appendix 7.4 to JGN's original submission) that JAM's processes provide a robust framework for developing efficient cost forecasts.[65]

Capex gating process for non routine capex

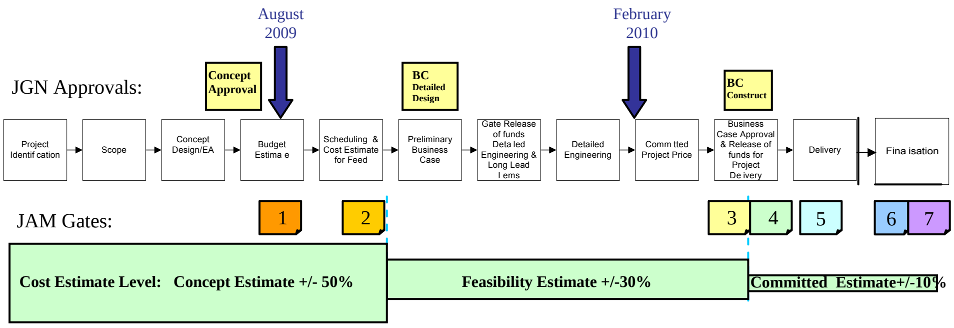
The non routine capex gating process involves multiple steps that take the project from problem identification through to finalised construction and transfer to JGN.

The gating process for non routine capex involves seven gates. A gate is a point where JAM requires internal sign off before the project can progress to the next stage in the process. The gating process also incorporates approval from JGN as the asset owner at designated gates.

Figure 3-1 below sets out the multiple step gating process and the progress of capex projects commencing in the 2010-11 regulatory year through the process.

65 PB, *Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision*, p. v.

Figure 3-1: Project gating and approval process for non routine capex



Typical non routine projects for the capital plan and gating process are identified via capacity monitoring and planning activities, field reports, incident reports or integrity reviews. Once identified the problem undergoes engineering assessment to determine possible solutions. This process can occur anywhere from one to six years out from project commencement. If a capital solution is required, the timing and scope of the problem and possible solutions are documented. A budget estimate is then developed for each viable solution and the lowest cost option is selected. In some rare cases, different options may give rise to similar costs. In those cases, more detailed costing is undertaken to determine the most prudent and cost efficient solution.

Table 3-5 summarises the various gates in the gating and approval process for non routine projects.

Table 3-5: JAM gates in the gating and approval process for non routine capex

Gate	Explanation of the decision taken by JAM
1	Identify the preferred option based on scope, timing and budget cost estimate of project. If the project is deemed compliant then it is progressed to gate two. A budget cost for the project will be developed for the option to be included in the capital budget.
2	Determine the feasibility of the project based on feasibility cost estimate, ±50% various options are put forward and considered by JAM. From the options selected a detailed business case for expenditure on additional engineering in order to undertake detailed design for the project can be produced or a concept approval business case can be developed. A detailed design business case will have a +-10% estimate for the delivery of the detailed design and a +- 30% estimate for delivery of the construction of the project.
3	JAM develops and approves the committed estimate for construction utilising the knowledge gained from the detailed design.
4	JAM develops a business case for the construction and submits it to JGN for

Gate	Explanation of the decision taken by JAM
	approval.
5	JAM approves a review approved business case and construction documents.
6	When JAM receives approval to proceed they initiate the project with the necessary paper and establish financial cost centres. When the project has reached practical completion it is handed over to the operation groups. Outstanding issues are managed via a punch list through to completion of the project.
7	JAM undertakes the project and financial close out of project.

If a project is deemed noncompliant at any of the above gates it is returned to an earlier gate. The gate the project is returned to depends on the nature of the concern identified.

Overlaying the JAM gating process is the JGN approval process. Table 3-6 outlines the key stages in the approval process for non routine capex.

Table 3-6: JGN approvals in the gating and approval process for non routine capex

Approval	Explanation of Decision
1. Concept Approval	For large, complex jobs spanning a number of years a business case is developed explaining the project and its expected costs, timing and financial benefit. The business case is developed solely to determine whether the project is feasible and can proceed. The business case does not constitute a request for funding.
2. Detailed design Approval	A business case to deliver the detailed design is developed. The business case must include an accurate estimate of the costs that will be incurred in completing the project, based on quotes received by JGN. Based on this business case, JGN will either approve or reject the release of funds for the detailed engineering.
3. Construction Approval	A final business case is prepared by JAM for the delivery of the construction phase of the project. This uses any detailed design that has been completed as a basis of the scope to obtain tenders to carry out the construction. The business case builds on the previous business cases completed and is submitted to JGN for approval.

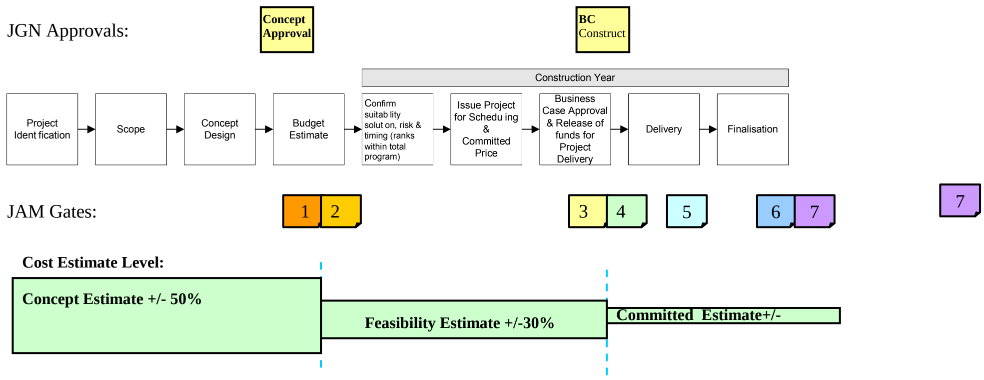
Capex gating and approval process for routine capex

The gating process for routine capex projects is simpler and faster than that for non routine capex. The systemised nature of the design process for routine capex means that a detailed engineering assessment is not required. This also means the feasibility estimate and business case for detailed design are not required.

Therefore, whilst the same gating process is used, projects progress through the gates process faster.

Figure 3-2 below summarises the gating and approval process for routine capex projects.

Figure 3-2: Gating and approval process for routine capex



Cost estimation to support efficient scope of capital works

The AER and Wilson Cook were satisfied that the scope of most capex projects proposed by JGN was reasonable.[66] However, the AER draft decision expressed concern that JGN had not provided sufficient information to enable it to assess the efficiency of JGN's cost estimates.

The nature of capital projects is such that, as the level of detail and information about a project increases, the accuracy of the cost estimate increases. This is reflected in the gating process outlined above. Under this process, cost estimates for projects with a fixed and known scope of work are determined on the basis of quotes obtained by JAM. This means cost estimates for these projects reflect the actual cost JAM would incur to complete the work. In contrast, projects which do not have a defined scope are valued on the basis of high level estimates. For example, these estimates may be based on previous jobs of a similar scope or determined using average cost per meter.

Table 3-5 set out that JAM prepares three cost estimates for non routine capex. The nature of these cost estimates is set out in Table 3-7 below.

[66] Wilson Cook report, p. 48 and Draft decision, p. 70.

Table 3-7: Cost estimates produced as part of the gating and approval process for non routine capex

Approval	Explanation of Decision
Budget Estimate	Prepared for gate 1. A budget cost estimate is derived on the basis of the historical costs incurred in similar projects completed in the past or similar unit rates utilised for routine jobs. It takes into account a high level scope and concept design. No field activity will have been completed at this stage and it will have significant contingency and potential to vary.
Feasibility Cost Estimate	Prepared for gate 2. A definitive decision has been made to follow a particular option and a scope of work has been prepared for that option. As a result, the estimate provides a committed indication of the cost that will be incurred to complete the design and an estimate of the costs that will be incurred to complete the job. This allows monitoring of the total project cost against the original budget estimate.
Construction Cost Estimate	Prepared for gate 4. A committed project price is produced based on tendered prices of construction using a detailed scope and clear understanding of the project deliverables.

As the above table indicates, the nature of the cost estimate produced at each gate is consistent with the decision making that is made at that gate.

Napier & Blakeley state JGN uses "concept estimating techniques that are consistent with other peer construction or infrastructure related industries and relevant to the amount of design information available at each stage of the project".[67]

Table 3-7 shows the progress of a project through the gating process results in refined cost estimates for the project resulting in a committed cost estimate based on tendered prices that is the basis of the business case. These increasingly refined estimates are:

- *Budget estimate* – At the budget estimate stage for a mains replacement the cost estimate is based on an estimate from assessment of maps and photos. The length of the main, the diameter of the pipe, configuration of facilities and topography of the site has not been assessed in detail.

- *Feasibility estimate* – A feasibility cost estimate is more detailed. It includes a committed cost for the delivery of the design. Depending upon the size and makeup of the project it could be generated from a service provider quote from or a price delivered from a tender. It will also include a high level

[67] Napier Blakeley, *Jemena Gas Networks (NSW) Access Arrangements 2010: Expert Terms of Reference – CAPEX Review*, March 2010, p. 2.

estimate for the completion of the construction utilising an assumption of what will come from the detailed design.

- *Construction estimate* – A construction cost estimate is based on the tender cost of delivering the final project fabrication or construction. This estimate utilises the information from the detailed design to inform the construction process. Depending on the project's size, these estimates are either from tenders or supplier quotes.

Napier & Blakeley find "The various stages of estimating in the JAM gating process move through a similar sequence to that which I have used as an estimator and cost planner within the construction industry and mirrors procedures I have experienced and seen used by other major construction and civil engineering groups."[68]

Nature of costs reflected in forecast of JGN's capital projects

JGN is confident that its forecast capex represents the costs that 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. This is because, in the majority of cases, the majority of costs JGN incurs in a capital project are determined through a competitive tender process conducted by JAM. As noted above, JAM is a leading Australian asset manager providing asset managing services to a range of infrastructure owners, and its projects are therefore very attractive to tenderers. This attraction is evidenced by the 23 requests for tender documents received by JAM in relation to the Wakehurst Parkway project.

JGN also benefits from JAM's ability to tender for large panel contracts servicing multiple JAM clients with associated scale benefits. The larger size of JAM's contracts and the frequency which it goes to market makes it a more attractive contracting partner for counter parties than JGN and results in more competitive tenders. In addition, larger purchase quantities mean that JAM can be expected to receive a better price than what would be available to JGN alone.

JAM also provides JGN with project management services, including:

- establishing engineering and design basis to ensure that the expected asset satisfies the necessary performance outcomes

- ensuring delivered projects comply with all relevant legislation and standards

[68] Napier Blakeley, *Jemena Gas Networks (NSW) Access Arrangements 2010: Expert Terms of Reference – CAPEX Review*, March 2010 , p. 2.

- ensuring that delivered asset fulfil the design specification
- managing contractor and vendor relationships, including logistics
- forecasting, monitoring, controlling and reporting on costs and cash flow.
- developing project contracting, procurement and risk strategies
- scheduling and delivering of achievable project milestones and sub activities within an agreed timeframe

JAM's size will translate into cost savings for JGN as the larger size of contracts and the frequency which it goes to market make it a more attractive contracting partner for the counter parties, meaning tenders tend to be more competitive. Larger purchase quantities mean that JAM can be expected to receive a better price than what would be available to JGN alone.

The vast bulk of other aspects of construction projects are sub contracted out by JAM through competitive tenders. JAM has two tender processes. Periodically JAM tenders contracts for routine capex by work within a geographic area. During the contract period routine construction projects in an area are assigned to the tender winner if they have the appropriate competencies and skills.

In most cases individual non routine capex projects are sent to competitive tender for detailed design and construction, as set down in JGN's procurement policy.[69] Also in accordance with that policy where the cost of the detailed design is expected to exceed $250,000, it will be competitively tendered.

A very small proportion of construction costs are provided through contracts which are selectively awarded where it is either more efficient to undertake a particular aspect of construction through selective contracting rather than competitive tender, or where it is not feasible to competitively tender. However, this approach is only taken if, given the circumstances, it is demonstrably more efficient than competitive tendering, or (for example) in the case of restorations, the works are required to be undertaken through a monopoly provider, i.e., the relevant local council.

Figure 3-3 and Figure 3-4 below show the direct costs the average proportion of each routine and non routine capex project which is awarded through competitive tender, selective contracting ('other'), or insourced and performed directly by JAM employees. These diagrams clearly demonstrate that the bulk of JGN's expenditure is incurred following a competitive tender process, often across multiple JAM clients' needs.

[69] Appendix 3b.11.

Figure 3-3: Project percentage cost by cost type for routine capex

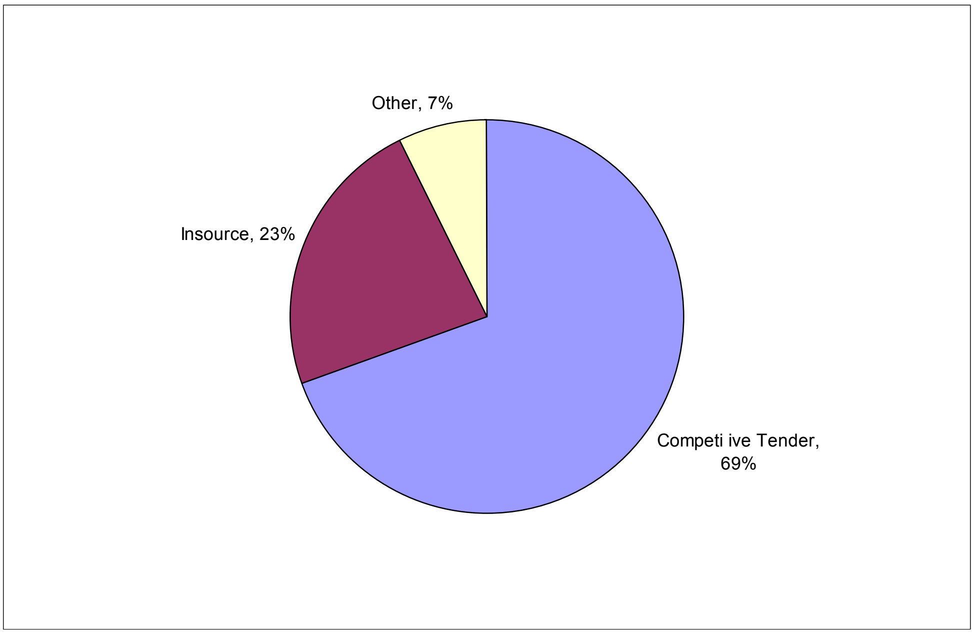


Figure 3-4: Project percentage cost by cost type for non routine capex

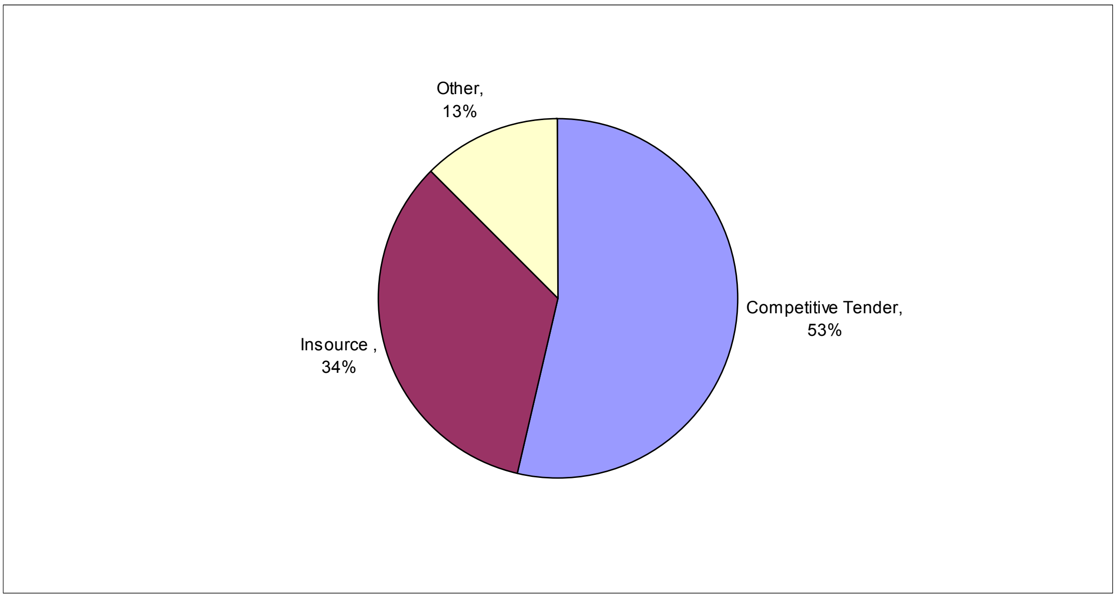


Figure 3-3 and Figure 3-4 are both inclusive of margin and overhead

Parsons Brinckerhoff have reviewed the major current non routine projects and costing process that are at gates 2 and 3.

Napier & Blakeley have reviewed the cost models/estimating process for routine projects.

PB review of non routine projects

PB have reviewed JAM's cost estimates and forecast projects and conclude that there is evidence that forecast estimates for the projects reviewed represent efficient values.[70]

PB's supplementary report in appendix 3b.1 notes that actual project costs, based on competitive tender prices, as the basis for estimating unit rates is demonstrably efficient. PB state that a competitive tendering process produces efficient project costs.[71] Therefore, if the competitive tender prices have been used to establish estimating unit rates then the cost estimates should also be considered efficient.

JGN has also forecast the use of lower cost technical solutions which PB observe results in a forecast below the cost of current standard practice.[72]

PB reflect on JGN's move to the use of standard designs, noting that they are anticipated to result in the lowest whole of life cycle cost[73] which JGN considers support achievement of lowest sustainable cost.

Napier & Blakeley review of routine projects

Napier & Blakeley have reviewed JGN's cost estimating process and the cost estimates it produces, see appendix 3b.2.

Based on its review, Napier & Blakeley concluded that the JAM cost model and estimating process are consistent with what it could be expected a prudent service provider acting efficiently, in accordance with accepted good industry practice would use.[74]

They further concluded that the JAM estimated costs for routine capital expenditure projects incorporated in the JGN submission to the AER have been established using estimating and cost planning parameters that a prudent service provider would adopt.

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70 PB, *Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision*, p. vi.

71 PB, *Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision*, p. 6.

72 PB, *Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision*, p. 7.

73 PB, *Jemena Gas Networks Access Arrangement – Supplementary report in response to AER's draft decision*, p. 7.

74 Napier Blakeley, *Jemena Gas Networks (NSW) Access Arrangements 2010: Expert Terms of Reference – CAPEX Review*, March 2010 , p. 2.

Napier & Blakeley also found that JAM overhead costs and profit margins are applied in the typical industry format and sit within the acceptable average range of margins that are evident within the construction and engineering industries.

While the majority of JGN capex projects are subject to the gating and approval processes outlined above, there are two categories of project that are approved in similar but separate processes. These are: market expansion capex and non system assets.

3b.3.6 Other approval processes

System expansion capex

System expansion capex refers to customer connections to JGN's network.

When a customer or developer contacts JGN requesting a connection to its network, JGN assesses the present value of the estimated connection costs and incremental operating costs against the present value of the incremental revenue that will be generated by the new or changed service. Where the costs exceed the revenue then the customer will be charged a customer contribution fee equal to the difference. This approach ensures that only justifiable costs (within the meaning of rule 79(2)(b) of the NGR) are added to the RAB.

As Wilson Cook noted in their report, JGN's forecast system expansion capex is calculated by applying unit rates of construction to the individual volumes of mains, services and meters by customer class. The volumes of mains, services and meters are derived from forecasts of new customer connections. In updating its forecast capex, JGN has updated its system expansion capex to reflect the new forecast of customer connections but has used the same unit rates as were included in its original proposal. In this regard, JGN notes that Wilson Cook recognised that those unit rates were within an expected range.[75]

Non system assets

The major categories of expenditure under the non system assets category are IT and motor vehicles.

As noted in JGN's original proposal KPMG undertook a detailed review of JGN's forecast IT expenditure and found it to be prudent and efficient.

In relation to the other expenditure category of note in the non system assets, motor vehicles are replaced under a process which ensures that all vehicles are purchased through competitive tender. The forecast is based on the cost of recent

75 Wilson Cook & Co, *Review of Expenditure of ACT & NSW Gas Distributors: Jemena Gas Networks (NSW) Ltd,* p. 56.

vehicles. The details of JGN's motor vehicle replacement capex are in appendix 3b.8.

The same policy and forecast methodology that applies to other projects applies to the other small items that make up non system assets.

3b.3.7 Current project gating status

At the time of JGN's original proposal, the cost estimates for projects expected to commence construction in 2010-11 were based on budget estimates. Consistent with its gating process and internal JGN's capital planning processes, JAM has now finalised detailed designs and project prices for the majority of these projects. In addition, JAM will have finalised business cases for each of these projects by 1 April.

New information from 2009 winter gauging

Each winter JAM undertakes winter gauging of its system. Broadly, winter gauging involves measuring pressure at key points on the network at high load periods and checking that the network's actual performance is following that forecast by the network model. If actual gauged demand is higher than the model prediction the actual numbers are utilised in the model to determine the impact on the network's pressures and ability to supply the gauged demand.

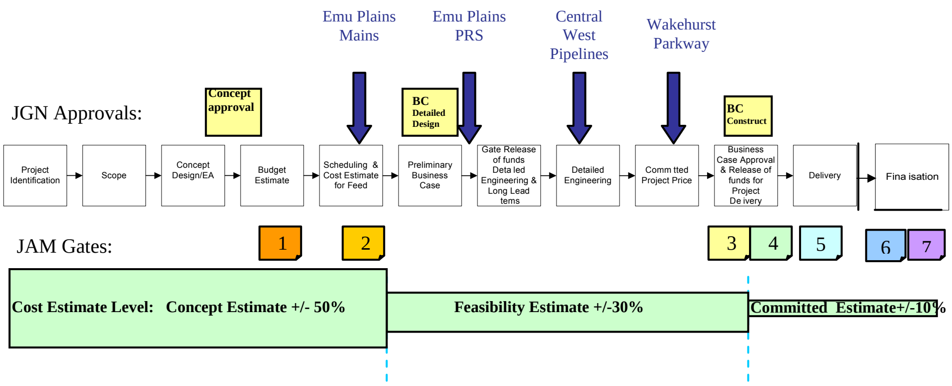
This modelling allows JAM to do a number of things including, identifying new areas which may be constrained or require additional work in the future, and allowing JAM to optimise the timing of projects to rectify previously identified issues.

The system analysis based on the winter 2009 figures has been finalised since the capex forecast was prepared for JGN's original proposal. This has enabled to JAM to update the timing of its forecast projects.

The update removes some proposed projects from the forecast capex from the next AA period as the current modelling indicates that they can be safely delayed until a later time.

Figure 3-5 shows how the 2010-11 capex projects have proceeded through the planning, estimating and approvals process to date.

Figure 3-5: The location of capex projects commencing in 2010-11 in the planning, estimating and approvals process



3b.3.8 *Detailed design and estimate refinement*

In total 41 projects have advanced in the planning, estimating and approvals process. JGN has now produced more up to date cost estimates for these projects using:

- the refined project design information
- updated expert determined demand forecasts
- updated expert determined input cost escalators

Detailed information about each updated project is set out below. In addition, and as noted above, JGN has also provided an up to date business case for each project in appendix 3b.12.

Wakehurst Parkway

The Wakehurst Parkway and Lane Cove PRS is designed to ensure continued supply to 10000 customer in the Northern beaches area of Sydney by providing for the installation of a high pressure 1,050kpa main 11 kms down a two lane roadway. This project is consistent with rule 79(2)(c) of the NGR.

JGN's August 2009 proposal estimated the cost of this project to be $11.7 million. This estimate was based on the preliminary engineering assessment of the project and assumed that steel pipes would be used.

Consistent with the gating process, a detailed engineering design has now been completed for the Wakehurst Parkway project. This has enabled JAM to determine a more accurate cost forecast for the project. The project is now forecast to cost

$14.1 million ($2010). This estimate is based on the use of polyethylene pipes, instead of steel.

At gate two of the gating process, JGN approved a request for $300,000 to undertake a pipe condition survey to obtain a better understanding of the project requirements. As a result of this survey, JAM has found that the continued use of steel would result in the forecast cost of the project being $22 million. This makes the use of polyethylene a more prudent and efficient alternative and therefore the preferred option.

This increase in the project costs is as a result of general cost increases in inputs.

Table 3-8: Wakehurst Parkway forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	10.0	1.2	0.0	0.0	0.0	11.2

Central West Pipeline

The Central West Pipeline project will enable the packaged offtake stations to comply with operating requirements given the increase in proposed operating pressures on the APA pipeline. Redesigning the POTS and installing waterbath heaters to achieve this is consistent with rule 79(2)(c) of the NGR. This is necessary to ensure the safe delivery of gas to the Central West and Riverina including Leeton and Griffith.

The Central West Pipeline is currently at gate two. Costs have been revealed to be significantly higher than initially budgeted. The initial engineering assessment and budget estimate was based on the delivery of the project under the existing design and contingency policies. Progress through the detailed design identified that following this process would see costs significantly higher than budgeted. An alternate option was identified that would allow construction at a lower cost but with deviation from JAM's technical policy.

The cost increase has been driven by the need for individual water bath heaters and the complexity of working on a brown field site. The design performed in order to meet the requirements for the gate has identified a movement in cost of the project to $7.2 million. JGN's original forecast for this project was $6.2 million.

Table 3-9: Central West Pipeline forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	7.2	0.0	0.0	0.0	0.0	7.2

Emu Plains

The Emu Plains primary regulating station (PRS) and mains project will ensure continued supply to 6,000 customers in the Blue Mountains region which at present is supplied by a single main that is reaching capacity. This will involve expanding the primary main across the Nepean River and installing a new PRS. This project scope is justified under rule 79(2)(c) of the NGR.

For the purposes of the gating process the emu plains project has been split into two projects; one relating to the PRS and one to the mains. The PRS is currently at gate two and has undergone a more detailed cost estimate of $2.7 million.

The mains projects progression through the gating process has been delayed due to the multiple authority approvals (Rail Corp, Council authorisations, Department of Primary Industry and Investment authorisations to drill under rivers and the like) necessary to determine the best route. As a result the project has yet to reach gate two. However an initial, more detailed design specification has been prepared. Based on this design, the project is forecast to cost $9.8 million. Ongoing Authority discussions and approvals will allow the project to progress to gate 2.

Therefore, combined, the Emu Plains PRS is now valued at $12.2 million. JGN's original submission estimated the cost of this project at $8.2 million.

Table 3-10: Emu Plains forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	5.2	7.0	0.0	0.0	0.0	12.2

3b.3.9 Revised escalators

The AER assessed JGN's proposed escalators in detail in the capex section of the draft decision as relevant to both capex and opex[76]. JGN follows the same approach in this section.

JGN's original proposal

To better reflect trends in raw material prices and labour market conditions leading to real increases in wages and salaries, the Competition Economists Group (CEG) was commissioned to produce a set of escalators for the access arrangement period. JGN applied these escalators in producing its capex and opex forecasts[77].

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76 Draft decision, p. 58.

77 JGN access arrangement information, 25 August 2009, sections 6.4.3 and 7.6.

AER draft decision

The AER draft decision did not raise any methodological issues with the labour, steel or aluminium escalator forecasts prepared by CEG. However, in respect of labour, the AER stated that since the publication of the CEG report and the base information on which it relied, there had been significant changes in the economic outlook, as well as fluctuations in some relevant economic data[78]. The AER therefore engaged Access Economics to produce updated labour cost forecasts. For similar reasons, the AER also updated the steel and aluminium escalators submitted by JGN. In respect of polyethylene and concrete, the AER did not accept the escalators prepared by CEG, and required that these be set to zero[79].

The AER draft decision stated:

> ...the AER is not satisfied that the proposed cost escalators comply with the requirements of r. 79 of the NGR and r. 74(2) of the NGR. As a result the AER requires Jemena to amend its forecast capital expenditure by applying the real cost escalators set out in Table 3.11 and amendment 3.3 below. The AER considers that these escalators should be updated in the final decision to allow for consideration of changes in economic circumstances and updated data to meet the relevant rule requirements[80].

The table below sets out the updated real cost escalators proposed in the AER draft decision.

Table 3-11: Amendments the AER required in its draft decision for capex escalators (Table 3.11 draft decision: Capital expenditure escalation factors for Jemena (%, real))

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
EBA EGW labour	2.1	0.1	0.5	1.1	1.5	1.4
Contract labour	2.1	0.1	0.5	1.1	1.5	1.4
Aluminium	-4.9	30.0	16.2	6.6	2.5	-2.4
Steel	-27.7	34.6	20.9	5.1	1.0	-1.0
Polyethylene	0.0	0.0	0.0	0.0	0.0	0.0
Concrete	0.0	0.0	0.0	0.0	0.0	0.0

[78] Draft decision, p. 61.

[79] Draft decision, pp. 63 and 64.

[80] Draft decision, p. 66.

Background

JGN's August 2009 AAI submission included (at appendix 6.4) a report JGN commissioned from CEG estimating cost escalation factors for:

- labour paid under enterprise bargaining agreements (EBA)
- labour paid under individual contracts
- aluminium
- steel
- plastics (nylon-11/polyethylene)
- concrete.

In the same report, CEG also estimated the extent to which the planned introduction of a Carbon Pollution Reduction Scheme (CPRS) was likely to affect the escalation factors for aluminium, steel, nylon-11/polyethylene and concrete.

JGN response

JGN considers that the AER may have made two errors in relation to the cost escalators proposed by JGN.

First, the AER draft decision erroneously found that JGN's cost escalators for capex were based on calendar years, stating:

> While the AER considers that Jemena's proposed use of financial years to project operating expenditure is appropriate, it does not consider it appropriate to use calendar years for capital expenditure. Instead, financial years should be used for both operating expenditure and capital expenditure[81].

In fact, JGN used financial year escalators for both capex and opex.

Secondly, the AER draft decision erroneously stated that JGN proposed an average input cost escalator for capex materials, stating:

> The AER notes that Jemena proposes to include cost escalators for a number of input materials. To do so, it uses a general materials cost escalator which is a simple average of the escalators for aluminium, steel, polyethylene and concrete[82].

81 Draft decision, p. 60.

82 Draft decision, p. 62.

JGN did not use an average input cost escalator for capex materials. However, this was done for opex.

AER replacement of JGN labour cost and other escalators

To forecast the escalation of JGN's EGW (electricity, gas and water) labour costs, CEG commissioned forecasts from BIS Shrapnel and Macromonitor. For EBA wages, CEG also used forecasts prepared by Econtech.

The AER draft decision stated:

> The AER considers that since the publication of these reports, there have been significant changes in the economic outlook as well as fluctuations in some relevant economic data which may result in these older reports no longer providing the best forecast possible in the circumstances, as required by r. 74(2)(b) of the NGR.
>
> Therefore the AER commissioned a report from Access Economics to forecast labour costs for the electricity, gas and water sector of the Australian economy on a state by state basis to confirm whether weaker employment conditions in the electricity, gas and water sector has impacted labour costs[83].

The AER compared the Access Economics and CEG forecasts and concluded that the Access Economics forecasts better accounted for more recent developments in the economic outlook. As a result, the AER proposed not to approve JGN's proposed labour escalators and to substitute the escalators prepared by Access Economics. The AER draft decision conceded that, unlike the CEG analysis, the Access Economics report did not forecast business specific EBA and labour cost escalators. Nevertheless, the AER considered that it would be appropriate to replace the business specific escalators submitted by JGN with the broader and less precise Access Economics forecast on the following grounds:

> The methodology used by Access Economics forecasts wages using a formal macroeconomic model based on business cycle factors, productivity factors and relative wage factors. This approach does not include analysis of business specific arrangements such as collective and individual agreements. Even though Access Economics uses industry sector data to forecast labour cost escalators, the AER considers the fact that these forecasts are able to take into account more recent developments in the labour market more than offsets any limitations in not being able to forecast EBA and contract cost escalators.[84]

83 Draft decision, p. 61.

84 Draft decision, p. 61.

The AER also updated JGN's aluminium and steel escalators on the ground that this provided the best forecast possible in the circumstances, as required by rule 74(2)(b) of the NGR and for consistency with rule 79 of the NGR[85].

JGN response to AER replacement of JGN labour cost and other escalators

JGN observes that the AER raised almost identical issues with respect to escalators in the AER's draft decision on the ActewAGL Gas Distribution (ActewAGL) July 1 2009 access arrangement proposal. Namely, that there had been significant changes in the macroeconomic outlook since ActewAGL submitted its access arrangement proposal, and that therefore updating of the relevant cost escalators was required[86.] As with JGN, the AER engaged Access Economics to provide an updated set of labour escalators for ActewAGL and the AER itself updated ActewAGL's steel and aluminium escalators [87.]

In the ActewAGL draft decision, the AER did not raise any methodological issues with ActewAGL's labour, steel or aluminium escalator forecasts prepared by CEG[88.] On this basis, JGN therefore considers that, for these escalators, the AER's concern related primarily to the time at which those escalators were estimated or forecast.

Following its review of the AER's draft decision, ActewAGL considered it appropriate to update its forecast escalators in its response to the draft decision to take account of recent market developments[89.]

To that end, ActewAGL commissioned an independent report from CEG to update its forecast escalators to take account of recent market developments. The escalators were prepared using the same methodology used in the ActewAGL Distribution forecast submitted in June 2009[90] and in JGN's August 2009 proposal. ActewAGL provided the updated CEG report as attachment E1 to its *Addendum to Access Arrangement*, 6 January 2010.

The AER's escalator timing concerns are essentially the same for JGN and ActewAGL. Therefore, the recently-updated CEG escalators provided to the AER by ActewAGL are equally applicable to JGN's capex and opex cost escalators.

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85 Draft decision, p. 63.

86 AER, *draft decision, ActewAGL access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network*, November 2009, p. 37.

87 AER draft decision, ActewAGL access arrangement, pp. 37 and 38.

88 ActewAGL Distribution, *Addendum to Access Arrangement Information for the ACT, Queanbeyan and Palerang Gas Distribution Network*, 6 January 2010, p.24.

89 ActewAGL Distribution, *Addendum to Access Arrangement Information*, p. 24.

90 ActewAGL Distribution, *Addendum to Access Arrangement Information*, 6 January 2010, pp. 24 and 25.

Therefore, provided those escalators deal with substantially the same subject matter as JGN's escalators, they should be able to be applied to JGN's capex.

The ActewAGL draft decision notes that the relevant categories of input cost escalators submitted by ActewAGL are enterprise bargaining agreement (EBA) labour for the electricity, gas and water (EGW) sector, contract EGW labour, aluminium, steel and polyethylene.[91] These are exactly the same escalator categories submitted by JGN, except that JGN had one more escalator – concrete.

CEG's technique for estimating aluminium, steel and polyethylene escalators for ActewAGL is by reference to overseas futures markets, and the same methodology was used in preparing JGN's escalators submitted in its AAI.[92] The updated CEG escalators for materials can therefore be applied equally to ActewAGL and JGN. However, the two labour escalators are business-specific and the question arises as to whether these particular ActewAGL escalators can be applied to JGN.

The following extracts from the CEG report for ActewAGL demonstrate that the ActewAGL labour escalators are equally applicable to JGN:

> For the purpose of forecasting future labour costs, ActewAGL has requested that CEG develop separate escalation factors for its EGW labour costs <u>that JAM incurs on its behalf:</u>
>
> - under its enterprise bargaining agreement (EBA); and
> - under individual contracts.
>
> Although JAM operates in ACT for ActewAGL, we understand that its EBA is a national agreement through Jemena, and that the majority of JAM's non-EBA staff are located in Sydney. Consequently we consider <u>that using New South Wales specific forecasts is likely to be reasonable and consistent with the AER's draft decision for the purpose of escalating ActewAGL's EGW labour costs</u>.
>
> For EBA EGW wages, we have used the average of the BIS Shrapnel EBA, Macromonitor EBA forecasts and <u>Access Economics NSW EGW forecasts</u> to extend forward the JAM data and create an index with which to estimate EBA EGW escalation factors.
>
> We have also used the specific BIS Shrapnel and Macromonitor individual contract EGW forecasts to project forward actual JAM data in order to derive these escalation factors[93].

[91] AER draft decision, ActewAGL access arrangement, p. 36.

[92] See CEG, *Escalation factors affecting expenditure forecasts – a report for Jemena Gas Networks (NSW),* June 2009, ss 3.2 -3.5; and CEG, *Escalation factors affecting expenditure forecasts – a report for ActewAGL*, January 2010, ss 2.2-2.5.

[93] CEG, *Escalation factors affecting expenditure forecasts – a report for ActewAGL*, January 2010, s 2.1, paragraphs 15-19. Emphasis added.

As the CEG labour escalators for ActewAGL are based on NSW data, they are equally relevant to JGN. JGN has adopted both the labour escalators and materials escalators in the updated CEG report prepared for ActewAGL. These are more recent forecasts than those submitted by JGN in its August 26 AAI submission[94], and thus address the matters the AER raised in the draft decision as to the time at which the CEG report relied upon by JGN was prepared. They are also more recent than forecasts in the Access Economics report which appear to be based on data as at June 2009[95].

The revised JGN escalators are set out in Table 3-12.

The updated CEG report for ActewAGL is attached as appendix 3b.5.

Polyethylene

While the AER accepted JGN's proposed approach for calculating real cost escalators for aluminium and steel, it did not do so for polyethylene and nylon-11.

> Like ActewAGL, JGN predominantly uses nylon-11 pipes. However, there is no liquid futures market or long-term price forecast available for this material. Therefore, the original CEG cost escalators reports for JGN and ActewAGL both submitted that polyethylene prices were a reasonable substitute for forecasting nylon-11 prices.[96]

In its draft decisions for both JGN and ActewAGL, the AER was not satisfied that CEG had devised a robust escalator for polyethylene as a proxy for nylon-11. The AER draft decision relating to JGN stated *inter alia*:

> The AER notes that neither Jemena's submission nor the CEG cost escalators report provides sufficient evidence to support a relationship between nylon-11 and crude oil prices other than the fact that nylon-11 and polyethylene are substitutes. The AER does not consider that the escalator has been arrived at on a reasonable basis.
>
> …when forecasting the price index for polyethylene, the forecast crude oil price index is based on the change in real crude oil prices denominated in Australian dollars. The AER does not consider this approach is appropriate as the estimated relationship between crude oil prices and thermoplastic resin prices includes the effects of inflation. Applying this approach leads to double counting of inflation as the forecast

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94 CEG note that the escalation factors are based on data collected in early December 2009. See *Escalation factors affecting expenditure forecasts – a report for ActewAGL*, January 2010, s. 1, paragraph 10.

95 Access Economics, *Forecast growth in labour costs - report for the Australian Energy Regulator*, 16 September 2009.

96 See CEG, *Escalation factors affecting expenditure forecasts – a report for Jemena Gas Networks (NSW),* June 2009, s. 3.5; and CEG, *Escalation factors affecting expenditure forecasts – a report for Jemena Asset Management*, June 2009, s. 3.5.

price, which includes the influence of inflation, is inflated again in the calculation of revenue[97].

Based on the concerns set out in the above paragraphs, the AER required that JGN's capital expenditure and operating expenditure proposals be amended to reflect a zero real cost escalator for polyethylene across the AA period (a similar requirement for the concrete escalator is discussed below).

JGN notes that the updated CEG report provided to ActewAGL has reviewed the AER's critique and has addressed the concerns raised by the AER.

To address the AER's concerns regarding the application of real price forecasts for forecasting crude oil, CEG's updated report has used forecast crude oil price movements expressed in nominal dollar terms to derive an econometric relationship between crude oil and polyethylene. CEG acknowledge that this change leads to a clear improvement in the accuracy of CEG's estimated escalation factors.[98]

In response to the AER's concerns regarding the price relationship between crude oil and nylon-11, CEG obtained a long term monthly pricing history for crude oil and thermoplastic resins. CEG has used this data series to run econometric estimates of the relationship between the two prices. The results show that movements in the price of crude oil explains approximately 22 per cent of the variation in the price changes of polyethylene, and that this relationship is significant at lags of 1, 2 and 3 months.[99] CEG therefore considered it reasonable to forecast polyethylene/nylon-11 on the basis of future crude oil prices.[100] The full discussion of CEG's calculation is contained in appendix A of the updated CEG report provided as appendix 3b.5.

In CEG's view, the AER's concerns regarding the price relationship between crude oil and nylon-11 did not justify setting aside the escalation factors estimated in the CEG report. CEG note that while the relationship between crude oil and nylon-11 is indirect, assuming zero real escalation without any supporting evidence or conceptual rationale is likely to be less precise.[101]

JGN agrees with this view, and has therefore applied the updated polyethylene escalator developed by CEG using the same methodology as used in the original CEG reports for JGN and ActewAGL (with the exception of using crude oil price

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97 Draft decision, p. 64.

98 CEG, *Escalation factors affecting expenditure forecasts – a report for ActewAGL*, January 2010, s. 2.5, paragraph 59.

99 CEG, *report for ActewAGL*, s. 2.5, paragraph 52 and Appendix A.

100 CEG, *report for ActewAGL*, s. 2.5, paragraph 53.

101 CEG, *report for ActewAGL*, s. 2.5, paragraph 60.

movements expressed in nominal dollar terms as discussed above). JGN considers this method represents the best forecast or estimate possible in the circumstance in accordance with rule 74(2) of the NGR.

Concrete

As noted earlier, Appendix 6.4 to JGN's August 2009 proposal included a forecast real price escalator for concrete (developed by CEG) to be applied to both capex and opex. The change in the concrete price acts as a proxy for construction activity.

The AER draft decision proposed not to accept JGN's proposed escalator for concrete. The draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to set a zero real escalator for concrete. The AER did not accept that JGN's escalator met the requirements of rule 74(2)(b) of the NGR. The AER discussion on page 64 of the JGN draft decision appears to suggest four reasons for this non-acceptance:

1. the AER did not know which of the three presented concrete indices[102] were being used
2. there was a divergence in the indices
3. the Macromonitor report did not demonstrate the statistical validity of the relationship between the annual percentage changes in the ready-mixed concrete used in houses price index and total construction work done
4. the forecasting methodology in the Macromonitor report was not transparent or reproducible.

In response to the matters raised by the AER in the draft decision on concrete price escalation, JGN commissioned CEG to do or provide a number of things:

- clarify which concrete index was used by Macromonitor to determine the forecast cost escalator for concrete
- assess the statistical validity of the relationship between the annual percentage changes in the ready-mixed concrete used in houses price index and total construction work done
- provide an explanation of the forecasting method employed by Macromonitor and provide an opinion on whether the Macromonitor forecasting method is

[102] This refers to page 22 of the Macromonitor report which accompanied the CEG report on escalators.

arrived at on a reasonable basis and represents the best forecast possible in the circumstances.

CEG was also asked to provide a revised forecast cost escalator for concrete for submission to the AER.

CEG's report is attached at appendix 3b.6. Macromonitors' updated forecast of the cost escalator for concrete is attached at appendix 3b.7.

The updated CEG report for JGN first makes clear which concrete index was used by Macromonitor. CEG then demonstrates the following:

- the AER's concern at the apparent divergence in the level of the indices presented by Macromonitor is groundless, given that the rate of change in each index is so similar to the other two indices over the extensive time period analysed.
- there is a clear and robust statistical relationship between the annual percentage change in the ready-mixed concrete used in houses price index and total construction work done. A 1.00 per cent change in construction work done gives rise to a 0.32 per cent rise in the price of ready mix concrete and there is only a 2 per cent probability (a P-value of 0.02) that the relationship identified is spurious (i.e. only a 2 per cent probability that higher construction work done does not result in higher ready mix concrete prices).
- the AER has no more reason to describe Macromonitor's forecasting methodology as 'non-transparent' or 'non-reproducible' than it would have to describe any other professional forecast in the same way.

Carbon pollution reduction scheme

CEG estimated the extent to which the planned introduction of a Carbon Pollution Reduction Scheme (CPRS) is likely to affect the escalation factors for aluminium, steel, nylon-11/polyethylene and concrete. These estimates were included in appendix 6.4 to JGN's AAI.

The AER draft decision did not accept these escalators:

> As forecasts for cost escalators that are based on future prices will already have the cost of the CPRS included, the AER does not consider that the proposed real cost escalators relating to the CPRS represent the best forecast possible in the circumstances as required by r. 74(2)(b) of the NGR. Accordingly, the AER does not accept Jemena's proposed real cost escalators relating to the CPRS.[103]

[103] Draft decision, p. 66.

JGN notes that a similar concern was raised by the AER in respect of the escalators submitted by ActewAGL[104] and that the updated CEG report provided to ActewAGL has addressed this issue. CEG states:

> We do not agree with the contention that the futures prices used by CEG already include the impact of the CPRS. The futures prices (and professional forecasts) used by CEG to develop its escalators were all based on US dollar prices in world markets for the relevant basic commodities (aluminium, steel, and crude oil). Even if investors in these markets fully factored in the expected impact of the Australian CPRS on world prices this would have no substantive effect on these prices.
>
> However, the work performed by CEG related to the impact of the CPRS on the transformation of these basic commodities into the finished products purchased by ActewAGL (aluminium products, steel products and nylon-11 (polyethylene used as a proxy)). This was based on estimates of carbon intensity in the relevant industries (plastic products, iron and steel, and basic non-ferrous metals and products). We submit that this impact is not captured in our escalators prior to the inclusion of the CPRS adjustment.[105]

JGN therefore considers that the updated CPRS escalators calculated by CEG for ActewAGL are reasonable and represent the best forecast possible in the circumstances, consistent with Rule 74. As a result, JGN considers that the updated CPRS escalators should be applied to JGN's capex.

Use of updated escalator forecasts in AER decisions

In the draft decision the AER stated that in order to make the proposal acceptable to the AER, JGN would be required to amend its labour, steel and aluminium escalators. [106] Additionally, the AER indicated that the escalators would be further updated for the final decision.[107]

In the draft decision the AER has indicated that it will update information in relation to cost escalators[108] closer to the date of the final decision. Implicit in the AER's draft decision is that in order for a forecast or estimate to represent the "best forecast or estimate" and therefore, to be consistent with rule 74, it must be a forecast or estimate that is generated closer to the final decision than the forecasts or estimates generated for the original or revised access arrangement proposal. The recent decision of the Australian Competition Tribunal relating to the selection

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[104] AER draft decision, *ActewAGL access arrangement*, pp. 40 and 41.

[105] CEG, *Escalation factors affecting expenditure forecasts – a report for ActewAGL*, January 2010, s. 3.2, paragraphs 68 and 69.

[106] For example see Draft decision, pp. 61, 66 and 203.

[107] For example see Draft decision, pp. 61, 66 and 203.

[108] Draft decision, pp. 61, 66 and 203.

of the period for the measurement of the risk free date and the debt risk premium indicates that this premise is not necessarily correct.[109]

An important purpose of the draft decision is to inform the relevant service provider of the determination of the AER in relation to the service provider's access arrangement revision proposal. In response to the draft decision, JGN is entitled to submit a revised access arrangement proposal to the AER which may incorporate amendments necessary to address the matters raised in the access arrangement daft decision (rule 60).

Rule 74 provides that a forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate *possible in the circumstances*. One relevant circumstance is the decision-making regime in which: JGN puts forward proposed revisions to its access arrangement; this is assessed by the AER in a draft decision; JGN is then entitled to submit additions or other amendments to the access arrangement proposal to address matters raised in the draft decision as well as make a submission on the draft decision; and the AER makes a final decision. In order for JGN to properly participate in the decision-making process of the AER, and for the draft decision to serve a real purpose, as a general statement, the last time at which the AER should update forecasts or estimates is as part of the access arrangement revision process.

The AER cannot consider a forecast or estimate that JGN puts forward as inconsistent with the rules solely on an assumption that a better forecast or estimate will be generated if relevant inputs to the forecast or estimate are updated closer to the final decision. Such an approach is: inconsistent with the decision of the Tribunal in *Application by EnergyAustralia and Others*; does not give real meaning to the role of the AER's draft decision; and disregards the requirement of the rules that JGN's forecast or estimate must represent the best forecast or estimate *possible in the circumstances*.

To the extent the AER concludes that, contrary to the above, it is appropriate to update any estimates or forecasts as part of its final decision, these estimates or forecasts should be provided to JGN a sufficient time prior to the final decision to allow JGN to consider and, if necessary, respond to those forecasts or estimates.

Exercise of limited discretion in relation to escalators

The draft decision did not contest the business specific methodology described by CEG for arriving at its labour escalators. To the extent the AER considered that the escalators put forward by JGN in its AA revision proposal were not consistent with the requirements of the Rules because of the time at which those escalators were forecast or estimated and the date of data inputs to the methodology, this

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109 *Application by EnergyAustralia and Others* (2009) ATPR 42-299, [90].

concern does not provide the AER with an ability under the NGR to replace the CEG methodology with an alternative methodology.

Where the AER has a limited discretion under the NGR, as it does in relation to capex and opex, the AER may only make changes that are necessary to correct non-compliance. Without conceding that JGN's forecast capex was inconsistent with the requirements of the NGR, the relevant non-compliance identified by the AER in relation to escalators was the date at which the escalators had been prepared and the date of the data inputs to the methodology used for determining the escalators. Therefore, what would be necessary to correct this perceived non-compliance is the application of the relevant methodology at a later point in time, using updated data – not, as the AER has done in the draft decision, a wholesale replacement of the methodology used by JGN (developed by CEG) with an alternative methodology preferred by the AER (that of Access Economics).

Update to the JGN access arrangement information

JGN has not incorporated the AER draft decision table 3.11 in respect of escalators. Instead, JGN has applied the updated labour, steel, aluminium, polyethylene, concrete and CPRS escalators prepared by CEG. These updated escalators are set out in table 1-11 below and use the weightings approved by the AER is its draft decision. JGN considers that these escalators are consistent with Rule 74 and represent a forecast or estimate that is arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

Table 3-12: **Amendments to JGN escalators to account for updated data**[110]

Escalator	Source of data	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Financial year escalators (excluding impact of CPRS)							
EBA labour	*CEG/ActewAGL*	1.9%	0.0%	1.4%	1.6%	2.2%	2.2%
Non EBA labour	*CEG/ActewAGL*	1.3%	1.2%	1.9%	3.4%	4.0%	3.3%
Aluminium	*CEG/ActewAGL*	-0.6%	34.7%	3.1%	0.6%	0.3%	0.5%
Steel	*CEG/ActewAGL*	-17.9%	41.9%	7.0%	-1.9%	-2.1%	-1.8%
Polyethylene	*CEG/ActewAGL*	-4.5%	28.6%	-0.5%	-2.6%	-2.6%	-2.3%
Concrete	*CEG/JGN*	-1.6%	-0.9%	2.6%	3.1%	2.0%	0.9%
Financial year impact of CPRS							
Aluminium	*CEG/ActewAGL*	0.0%	0.0%	0.3%	0.5%	0.1%	0.1%

110 Escalators are rounded. Actual modelling uses more precise figures.

Escalator	Source of data	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Steel	*CEG/ActewAGL*	0.0%	0.0%	0.8%	1.2%	0.1%	0.1%
Polyethylene	*CEG/ActewAGL*	0.0%	0.0%	0.3%	0.5%	0.1%	0.1%
Concrete	*CEG/JGN*	0.0%	0.0%	0.3%	0.5%	0.1%	0.1%
Consolidated escalators (real)							
EBA labour	*Calculated*	1.9%	0.0%	1.4%	1.6%	2.2%	2.2%
Non EBA labour	*Calculated*	1.3%	1.2%	1.9%	3.4%	4.0%	3.3%
Aluminium	*Calculated*	-0.6%	34.7%	3.4%	1.0%	0.4%	0.6%
Steel	*Calculated*	-17.9%	41.9%	7.8%	-0.7%	-1.9%	-1.6%
Polyethylene	*Calculated*	-4.5%	28.6%	-0.2%	-2.1%	-2.6%	-2.2%
Concrete	*Calculated*	-1.6%	-0.9%	2.9%	3.6%	2.1%	0.9%

3b.4 Response to specific issues raised in the draft decision

As discussed in section 3b.2, the AER's draft decision raised a number of specific concerns in relation to JGN's proposed capex forecast. The following sections address each of these concerns and a number of JGN's own concerns with the draft decision conclusions, including:

- the AER's and Wilson Cook's interpretation of NGR Rule 79
- the commercial margin JGN pays to JAM for capex services
- JGN's capitalisation policy including:
  - reconciliation of capitalised overheads
  - an expert accounting opinion validating JGN's capitalisation policy as regards mine subsidence, integrity digs and pigging and ad hoc mains renewals
- specifically excluded projects relating to land, buildings and leasehold, contingency amount for customer services, metering and billing application software, organic growth infrastructure, IT expenditure for market changes to implement the access arrangement changes
- the AER's use of what it characterises as historic trends to set JGN's forecast capex

- the consequences for service levels and safety if JGN's capex forecast were to be constrained to the levels set out in the draft decision

- demonstrating JGN's ability to deliver its forecast capex

- equity raising costs.

3b.4.1 Interpretation and application of Rule 79 of the NGR in the AER Draft Decision

Rule 79(1) of the NGR defines "conforming capital expenditure" as capital expenditure which 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 on a ground stated in subrule (2).

The AER draft decision indicates that, for capital expenditure to be justifiable:

> it must be necessary having regard to one of the following grounds stated in r. 79(2) of the NGR:
>
> (i) to maintain and improve the safety of services; or
>
> (ii) to maintain the integrity of services; or
>
> (iii) to comply with a regulatory obligation or requirement; or
>
> (iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity).[111]

Footnote 101 of the AER draft decision notes that the AER has only included a sub-set of rule 79(2) (namely sub-rule 79(2)(c)) in the above passage.

In considering the meaning of the term "justifiable", the AER appears to have overlooked a number of important provisions relied upon by JGN to support its proposed capex.

[111] Draft decision, p. 16.

JGN relied on sub-rule 79(2)(b) of the NGR to show that its market expansion capex is justifiable. Under sub-rule 79(2)(b) of the NGR, capital expenditure is justifiable if:

> 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.

The AER draft decision notes JGN's reliance on this provision, stating:

> Jemena submits that its market expansion capital expenditure is consistent with rule 79(2)(b) of the NGR.[112]

However, neither the AER, nor its advisor Wilson Cook, expressly considered the application of this provision to JGN's market expansion capex.

Similar issues arise in relation to the AER's consideration of JGN's IT and communications capital expenditure. JGN justified its IT and communications capex on the basis of subrule 79(2)(a) (as well as subrule 79(2)(c)) which provides:

> Capital expenditure is justifiable if:
>
> (a) the overall economic value of the expenditure is positive.

The AER again noted JGN's reliance on this provision, stating:

> In relation to the IT capital expenditure, Jemena submits that it is justified because the overall economic value of the expenditure is positive.[113]

However, again, there is no indication that either the AER or Wilson Cook had regard to subrule 79(2)(a) of the NGR in determining whether JGN's proposed capex is justifiable.

Further, Wilson Cook's report states that 'requirements for capex related to future safety issues' and 'new statutory requirements' were excluded from the scope of its review.[114] This means Wilson Cook did not perform an assessment of JGN's historic or forecast capex against 79(2)(c)(i) or (iii). To the extent the AER has relied upon Wilson Cook's views to reject elements of JGN's capex, it should have first satisfied itself that JGN had not complied with these specific rules. The draft decision does not show that this occurred which is concerning given that Table 7-4 of JGN's original proposal identified that JGN had justified key elements of its capex forecast under these rules..

112 Draft decision, p. 34.

113 AER, *Draft Decision , Jemena Access Arrangement Proposal for the NSW Gas Networks 1 July 2010-30 June 2015*, 10 February 2010, p. 55

114 Wilson Cook, *Review of Expenditure of ACT & NSW Gas Distributors, Jemena Gas Networks (NSW)* , December 2009, p. 3.

JGN considers that the AER's failure to consider JGN's proposed capex against subrule 79(2)(a) and (b) has led to an incorrect outcome or decision. Under subrule 79(2) capital expenditure is considered to be justifiable where it satisfies any of the subparagraphs.

3b.4.2 Commercial margin

JGN has not incorporated the AER's amendment to remove the commercial margin payable to JAM under the AMA. JGN's response to the draft decision conclusions on this margin are set out in section 9.3.

3b.4.3 JGN capitalisation policy

JGN has not accepted the AER's draft decision amendments to remove capitalised overheads or expense certain capital works.

JGN's capitalisation policy determines what costs it capitalises including specific pipeline works and certain overhead costs.

Relying upon the conclusions of its engineering consultant Wilson Cook, the AER's draft decision rejected certain of JGN's capitalised costs including:

- capitalised overheads
- specific pipeline works relating to: mines subsidence; integrity digs and pigging; and ad hoc renewals.

Below JGN responds to each of these matters. It also provides a copy of its capitalisation policy in appendix 3b.3 and an expert accounting review of this policy in appendix 3b.4.

As a primary issue, JGN observes that the AER has relied upon an engineering assessment to determine what is essentially an accounting question. This is not only surprising because of the lack of suitable qualification, but because Wilson Cook's report explicitly states that reviewing JGN's capitalisation policy and other matters beyond its expertise were not in scope for its work.

> The review was limited to the context of our instructions[115] – specifically, the particular scope of work set out at the commencement of section 1 above.
>
> The following matters were excluded from consideration in our work or were not undertaken:
>
> - ... review of **the business's policies for the capitalisation of expenditure;**

[115] JGN notes that it has requested a copy of these actual instructions and that the AER has declined to provide them.

- ... review of expenditure other than that associated with the business's network business unit;
- ... **physical inspection of the assets;**
- ... consideration of the possible effects of the following factors that can only be conjectured:
  - requirements for capex related to future safety issues, new statutory requirements, new Government policies or initiatives, or environmental requirements except to the extent that they have been identified by the business; ...
- review of financial models;
- any **matters outside our field of expertise.** [emphasis added][116]

Wilson Cook concludes, and the AER accepted this conclusion, that certain of JGN's historic and forecast capex does not create a new asset or extend the life of an existing asset (eg, mines subsidence) and should not be allowed as capex.

JGN questions how these conclusions can be reached without:

- reviewing JGN's capitalisation policy
- inspecting the physical asset or detailed project plans to see if the expenditure did extend the life
- taking into account JGN's safety obligations that have motivated capex such as mines subsidence
- the necessary expertise to opine on a matter of accounting practice.

JGN considers that the NGR are not prescriptive about the delineation between capex and opex. JGN has applied an accounting capitalisation policy which it has had independently reviewed by Ernst & Young for compliance with the relevant accounting standards.

The following sections address capitalised overheads and costs the AER has deemed as not being of a capital in nature.

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116 Wilson Cook, *Review of Expenditure of ACT & NSW Gas Distributors, Jemena Gas Networks (NSW)* , December 2009, p.3 and 4.

Commercial in confidence

Capitalised overheads

JGN's capex forecasts include forecast JAM overhead costs. This percentage is a simplified proxy for forecasting purposes. The actual overhead costs JAM incurs will be included in the capex price paid by JGN.[117] In this way, JGN's forecast reflects a dollar value of capitalised overheads for each year of the forecast period rather than a percentage rate.

The draft decision required that in order to make the proposal acceptable to the AER, JGN's capex forecast should exclude the forecast capitalised overheads. The reasons given by the AER for this were:

- JGN has not reconciled these costs to show that they are not recovered in expensed overheads[118]
- JAM should only recover overheads on capital works it delivers in-house.[119]

Wilson Cook did not consider the overhead costs to be inefficient or imprudent, stating:

> The AER could also consider an adjustment to remove the overhead allocation that is believed to have been included in the estimates pending receipt of the justification and reconciliation from the business. However, we have not shown such an adjustment as, in principle, the capitalisation of overheads attributable to the construction and putting into operation of new fixed assets is acceptable (provided the amounts are identified and not also recovered through the operating expenditure estimate)'[120]

As JGN has previously advised the AER, these capitalised overheads relate to capitalised elements of the secondary WOBCA allocation to JAM as well as certain indirect capital costs that JAM incurs such as: initial engineering assessments not capitalised to a particular project, capacity planning and business case pricing.

Table 3-13 provides a summary of JAM's 2008-09 base year actual capitalised overhead costs. These show that JAM incurred $10.5 million in the base year.

[117] JGN, *Response to the AER 11 December 2009 questions*, 18 December 2009

[118] Draft decision, p. 46.

[119] Draft decision, p. 47.

[120] Wilson Cook, *Review of Expenditure of ACT & NSW Gas Distributors, Jemena Gas Networks (NSW)*, December 2009, p. 72.

Table 3-13: JAM 2008-09 capitalised overheads (A$M, regulatory year)

Category	JAM actual	
	2008-09	
Dollars	$2009	$2010

This actual capitalised overhead incurred in 2008-09 is a mix of cost that are fixed and other cost that are variable. The capital program for each year of the next period is larger than the 2008-09 program and therefore the amount of capitalised overhead that will be incurred in each of those years can be expected to be at least . Table 3-14 below demonstrates that JGN forecasting assumption of for capitalised overhead results in an implied forecast dollar amount for capitalised overhead that is less than the actually incurred in 2008-09 in respect of and can therefore be considered reasonable.

Table 3-14: JAM capitalised overheads ($ million 2010, regulatory year)

Category	JGN submitted				
	2011	2012	2013	2014	2015
JAM directs	151.29	146.25	146.59	158.07	171.41

JGN has confirmed the reasonableness and efficiency of its capex overhead forecast rate against that of its network peers and against decisions by the AER, ACCC and other jurisdictional regulators. This comparison found that

- regulators have universally accepted that capitalisation of overhead is reasonable and an economically efficient practice
- capitalised overhead allowances have varied from between 4.7 per cent and 30 per cent.

Commercial in confidence

Commercial in confidence

Appendix 3b.10 details this analysis and references examples within this range. JGN is the second lowest of all firms in this sample and is significantly lower than the average regulator approved rate of 15.3 per cent.

Recovery of overheads across total JAM costs

Finally, JGN wishes to clarify the draft decision conclusion that JAM should only recover overhead costs on capex that it delivers in-house. This conclusion is flawed and reflects both an over-simplification of the issue and a misunderstanding of the nature of the capitalised JAM overhead costs.

As discussed above, the forecast overheads have been calculated as a
rate, but this is only a proxy for the actual dollar value of costs that JAM will actually incur and bill to JGN. In this way, the dollar value will not move depending upon whether the underlying direct costs relate to services delivered in-house by JAM or subcontracted to other parties.

Napier & Blakeley state that it is standard industry practice to make allowance for both overheads and profit margins.[121] These are generally derived in the form of a percentage applied to the direct costs.

Based on the evidence above, JGN considers that its forecast capex for capitalised JAM overheads is consistent with both rule 79 and 74 of the NGR.

Capitalisation policy and application to specific pipeline works

JGN applies its capitalisation policy when recording pipeline works to its statutory accounts and regulatory asset base. Wilson Cook and the AER in its draft decision conclude that certain historic and forecast costs capitalised under this policy are not capital in nature.

Inherent in Wilson Cook's conclusion and the AER's draft decision as regards historic capex is a conclusion that JGN's audited statutory accounts have been incorrectly prepared and that neither JGN nor its auditors should have signed them off. JGN takes this issue very seriously and considers that this conclusion is without basis, particularly given this was a matter outside of Wilson Cook's scope of work.[122]

JGN engaged Ernst & Young to review its capitalisation policy for compliance with the interpretation and application of Australian Accounting Standards, which include Australian equivalents to International Financial Reporting Standards (AIFRS). JGN also asked Ernst & Young to comment on the four specific

121 Wilson Cook report, p. 3.

122 Wilson Cook report, p. 3.

instances in which Wilson Cook and the AER have contested JGN's cost capitalisation:

1. Appin mine subsidence
2. integrity digs
3. pigging
4. adhoc mains and service renewals

A copy of Ernst & Young's review report is provided in appendix 3b.4.

In all instances, Ernst & Young concluded the JGN's treatment of these costs in the statutory accounts is consistent with JGN capitalisation policy which in turn is consistent with the relevant Australian Accounting Standards. This is because the expenditure either increased the future revenue earning capacity of the network, extended the live of an asset or both.

In addition to this accounting opinion, JGN considers that the Wilson Cook logic in arriving at its conclusion that these specific costs are not capital in nature is flawed. Wilson Cook's reasoning is replicated for each of the 4 cost items above. This reasoning is summarised in its analysis of mines subsidence as follows:

> The work appears necessary but the question arises: why should the expenditure be capitalised if, **as we presume, no new assets were created or the lives of existing assets, when repaired, were not thereby extended**? We therefore consider that this expenditure should not be added to the regulatory asset base, although there ought to be a mechanism for the business to recover its efficient costs. [123][emphasis added]

JGN notes that it was never asked to clarify if any new assets were created or if the asset lives were extended. If it had been, JGN could have clarified that both these things were in fact the case. Appendix 3b.4 details why this is so for each type of pipeline works.

Further, JGN notes that the rule 79(2)(c) of the NGR identifies that capex is 'necessary' where it is required:

(i) to maintain and improve the safety of services; or

(ii) to maintain the integrity of services; or

(iii) to comply with a regulatory obligation or requirement; or

[123] Wilson Cook report, p. 52.

(iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)

JGN notes that 'requirements for future capex related to future safety issues' were identified by Wilson Cook as being not part of its scope.[124] Despite this, the AER does not provide any supplementary consideration of this relevant element of Rule 79 in its draft decision.

The four cost items rejected by Wilson Cook and the AER are all necessary in accordance with this Rule 79(2)(c) provision. JGN proposes that they should therefore be included in its historic conforming capital and forecast conforming capital as submitted.

3b.4.4 Excluded projects

Land, buildings and leasehold

JGN has included in its opex step changes an item for AMA contract managers. This capex relates to the provision of workstations and other leaseholds for these contract managers. The cost has substantially been revised downwards based on a different approach to providing workstations and office space than that which was included in the original submission. The capex associated with this is now $30,000 per year.

The details of JGN's proposal for this step change are outlined in appendix 9.5.

Contingency amount for customer services, metering and billing application software

The contingency amount disallowed in the draft decision related to the customer service and billing system project. This was 10 per cent of the project's capital value at a provisional cost of . The contingency allowance is necessary for the following reasons:

- a contingency on such a large project is normal prudent practice within the IT industry and for large projects more generally. The contingency allowance provides for possible increases in:
    - the level of staff resources required

[124] Wilson Cook report, p. 3.

- changes to licensing of international software that typically becomes richer in functionality and more expensive at each new release and so may increase fees

- the level of sophistication required to support the introduction of the new system and any associated increases in process automation and systems integration between now and project commencement

- costs due to uncontrollable external events such as IT staff availability shortages for that type of systems development driving up costs

- a 10 per cent contingency is a modest allowance by common IT industry standards which is normally much higher for such a large project some years away from commencement. In this case there is a recent similar project underway within the Jemena Group that has helped provide firm estimates for the contingency while still remaining prudent.

- the time span between the forecast and the commencement of the customer billing project is 3 years, therefore a contingency is prudent risk management

- given the pivotal role of the network operator in most market processes, functional initiatives led by market operators and regulators often requires supporting functionality to be added to network systems. A past example of this includes the introduction of data extraction and export software to assist retailers to identify customers for transfer.

Organic growth infrastructure

Organic growth refers to the annual incremental need and investment required to fund additional IT Infrastructure for IT hardware and in-house communications technologies. This is driven by:

- growth in the energy network requiring more data including the higher storage requirements of graphical, image and geo-spatial data

- customer and business growth

- growth in the use of technology as new applications are introduced such as the new Geographic Information System.

The provision for organic growth is to support the growth for IT infrastructure technologies, including central processing units, data storage and technical licenses. The provision will enable JGN to continue to maintain sufficient capacity for its IT needs. The growth rates are based on recent historical experience, and are largely a function of the number users of the IT systems and infrastructure provided. The organic growth costs forecast for IT Infrastructure is $2.491 million.

Wilson Cook made reference to two types of organic growth that required clarification:

1. the organic growth per software application - this grouping is specifically for applications licenses and end user growth investment excluding IT hardware technologies; and

2. the organic growth under the IT Infrastructure sub-section – this grouping is for capital growth supporting all of the hardware platforms in their entirety and all non-application software technologies. This category does include technical software licenses for database, tools, process-ware, middleware and software that operate the technology devices.

AER – Market changes and access arrangements

JGN's proposed AA for the next AA period involves the provision of revised reference services that require supporting application software asset development to facilitate billing and administration under the new AA. This will have an ongoing life of at least five years and therefore under JGN's capitalisation policy should be capitalised and not treated as IT opex. The following paragraphs outline the nature of the new AA and the required functional development.

JGN's proposed AA introduces a number of new and changed services that require modification to commercial systems to enable billing and administration. Currently, JGN meets its commercial obligations to network users in the NSW market via a suite of applications including the GASS and CABS systems.

The IT 'market changes and AA' project will update CABS with the functionality required to allow JGN to deliver its obligations under the proposed AA and the commitments it has provided to its network users including the introduction of "Chargeable Demand". New system functionality needed to support the AA includes a need to:

- migrate customers to new tariffs and tariff classes introduced in the proposed AA such as the demand first response tariff class, and manage both existing and new charging methods concurrently

- capture and store additional contract data to support new charging approaches, including storing delivery points in tariff classes

- implement Chargeable Demand calculation capability which fundamentally changes the approach to contract billing currently in place.

Indicative vendor pricing sourced since the forecast was provided as part of JGN's IT Strategy and Asset Management Plan has indicated the required changes for AA compliance alone will cost an estimated $2.2 million. The initial estimate of $1.05 million will be insufficient to cater for the breadth and complexity of change required.

However formal pricing has not yet been confirmed in order to justify an increase in the forecast submitted. This range further supports the concept of prudent contingency discussed above.

Table 3-15: IT forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	20.0	15.3	12.5	24.1	28.8	100.8

3b.4.5 Use of historic averages to set forecast capex

Based on the findings of its consultant, Wilson Cook, the AER concluded that it did not have sufficient information to assess the cost efficiency of JGN's forecast capex. In the draft decision the AER instead employed historic average expenditure to set forecast capex for:

- the majority of system reinforcement, renewal and replacement capex
- non system assets excluding IT, land, buildings and leasehold asset.

The AER adopted this approach despite its own consultants concluding that JGN's proposed scope of work appears reasonable.[125]

JGN's scope of work is demonstrated to be necessary and prudent

JGN's scope of work for the next period has been fully endorsed by PB's expert assessment and noted as being reasonable by Wilson Cook. This means the AER's approach in allowing only a historical level of funding necessarily implies a view that future unit rates will drop significantly to accommodate the scope increases within the same average expenditure. There is no basis for the AER to reach such a view. Significant evidence,[126] including the AER's own view of input cost escalators suggest otherwise.

[125] Wilson Cook report, p. 70.

[126] Napier & Blakeley, *Jemena Gas Networks (NSW) Access Arrangements 2010: Expert Terms of Reference – CAPEX Review*, March 2010 , section 11.

Use of historic averages requires an unachievable reduction in costs

Given the significant difference between the forecast scope and the historical scope, the implied reduction in unit rates arising from the AER's draft decision is simply not feasible.

A finding that unit costs are forecast to drop significantly is not consistent with the AER's findings in relation to cost escalators. The AER, relying upon Access Economics, concluded in relation to cost escalators that, for all escalators it forecast, costs would be higher at the end of the forecast period than at the beginning of the period.

The categories of forecast capex that have been dealt with in this arbitrary manner result in a significant reduction in funding for activities required to maintain the ability to operate JGN's network safely and deliver a reliable and uninterrupted service to existing consumers. This approach to underfunding forecast activities which are demonstrably required to maintain safe and reliable operation of the network is completely inconsistent with a service provider being provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs section 24(2) NGL.

The draft decision does not explain why the AER's substituted capex forecast satisfies the NGR requirements of rules 74 and 79.

Scope of forecast capex projects and implication of the AER's substituted forecast

To demonstrate the inadequacy of this historical approach Table 3-17 below sets out the major asset types involved in the system reinforcement, renewal and replacement capex categories, and indentifies volume for these asset types for the current period and volumes reasonably forecast to be required in the next period. The table also shows the typical unit cost and total cost forecast for each asset type in the next period and compares this to the overall historically based allowance determined by the AER.

Table 3-16: Asset Volumes associated with system reinforcement, renewal and replacement capex categories

Category	Description	Units	Actual projects volume	Forecast project volume	Typical unit rate	Forecast volume x average unit rate	AER allowance from draft decision
						($000)	**($000)**
Renewal and replacement	TRS/PRS	Unit	3	9	1,944	17,496	
Renewal and replacement	WBH	Unit	5	12	1,284	15,406	
Renewal and replacement	All other	number	n/a	40	n/a	63,866	
Total renewal and replacement						**96,768**	**28,295**
System reinforcement -capacity development	TRS/PRS	Unit	1	3	3,782	11,347	
System reinforcement -capacity development	MP mains	metres	27,793	94,769	188	17,811	
System reinforcement -capacity development	Sec Mains	Metres	3,650	56,620	532	30,106	
System reinforcement -capacity development	Wakehurst Parkway	Metres	2500	11,000	1,368	15,047	
System reinforcement -capacity development	Primary mains	Metres	0	8,142	2,380	19,379	
System reinforcement -capacity	All other	numbers	n/a	12	n/a	2,025	

Category	Description	Units	Actual projects volume	Forecast project volume	Typical unit rate	Forecast volume x average unit rate	AER allowance from draft decision
						($000)	($000)
development							
Total - System reinforcement -capacity development						**95,716**	**25,693**

Consequences of capex reduction

The table above clearly demonstrates the significant gap between the AER's proposed level of funding based on its historic average approach compared with the level of funding reasonably required to support the verified scope of work.

The projects contained in JGN's forecast system reinforcement, renewal and replacement capex will ensure that:

- the risk to the community from the operation of JGN's network does not increase;
- the MAOP of JGN's licensed pipelines can be maintained, thus enabling sufficient capacity to supply existing demand to be maintained;
- JGN can continue to supply towns in the Central West region of NSW (i.e. Dubbo, Forbes, Parkes, Narromine, and Wellington) following the proposed upgrade of operating pressures in the MSP pipeline system;
- During winter peak periods in the next period, JGN is able to maintain supply to terminal network areas such as the Blue Mountains, Pittwater, and southern Wollongong;
- JGN can avoid major unplanned outages arising from failure of key pressure reduction stations, potentially impacting tens of thousand of customers;
- the incidence of environmental impact through gas leakage does not increase; and
- JGN can remain compliant with its technical regulatory obligations.

At the funding level proposed by the AER, many of the outcomes listed above would not be able to be delivered by JGN.

For the reasons outlined above JGN has not incorporated the AER's amendments in relation to capital expenditure.

Specifics relating to projects reduced to historic average

The use of a historic average has affected all projects covered by a capex limit lower than forecast by JGN. In the non system assets category the most significant effects will be felt in relation to JGN's metering assets and its motor vehicle replacement program.

Motor vehicles

In relation to motor vehicles the AER's historic averaging approach results in a significantly lower forecast than what is needed to have a prudent and efficient motor vehicle fleet.

JGN forecast capex of $21.1 million for the next AA period. The AER more than halved this amount to $10 million. JGN is now proposing a capital expenditure of $16.7 million as a result of more detailed cost estimates, but still require a materially higher forecast than provided for in the draft decision.

JGN's motor vehicle replacement program is based on the JGN fleet management strategy. This strategy seeks to ensure that vehicles purchased are fit for purpose, low cost and contain all the appropriate safety features.

When this strategy is applied it requires a capex forecast as set out in Table 3-17

Table 3-17: Motor vehicles forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	3.5	1.7	2.3	6.0	2.1	15.6

Further details of JGN's forecast for motor vehicle capital expenditure are set out in appendix 3b.8.

Meter replacement capex

Applying an historic average to forecast capex on system reinforcement, renewal and replacement capex would result in an approach to metering and regulator replacement that under invests in JGN's metering population, and is insufficient for JGN to comply with its regulatory obligations in relation to metering accuracy.

JGN's forecast capex is consistent with the replacement profile of JGN's meters which is based on the age and accuracy of metering in place.

JGN's replacement program covers aged residential meters and regulators, aged I & C meters and aged water meters. The forecast for JGN's meter and regulator replacement capex is set out in Table 3-18

Table 3-18: Meter and regulator forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex	24.7	27.1	31.9	31.0	34.4	149.2

The details of JGN's forecast for meter and regulator replacement capex are set out in appendix 3b.9.

3b.4.6 JAM's capacity to deliver JGN's forecast capex

JAM is contracted to provide the capex on JGN's network. All projects that JAM undertakes on JGN's behalf are approved by JGN.

The AER's draft decision indicated that JGN does not demonstrate whether the proposed works can be undertaken within the proposed timeframes.

JGN's contract with JAM enables it to access the benefits associated with the scale and scope of JAM's operations both in terms of cost efficiency and capacity to deliver projects.

JAM is capable of economies of scale that would be not be available to JGN alone. JAM delivers an annual program of works to multiple clients in excess of $1,000m per annum. The increase in JGN's proposed capital program would represent a less than 10 per cent increase to JAM annual program of works.

JAM has a proven capacity to gear up to deliver critical capital programs for its clients, examples of this capacity includes:

- Sydney Primary Loop projects for JGN
- Colongra gas compression and storage facility for Delta/Jemena
- Victorian AMIRO implementation for JEN and UED,
- Orbost Gas compressor upgrade for EGP
- Pipeline capacity upgrade and looping project for QGP

JAM has processes in place to manage the delivery of projects. These processes relate to project management, procurement of materials and tendering of contracts.

JGN is confident of JAM's ability to deliver the proposed capex forecast for cost. As noted in section 3b.3.4, JAM competitively tenders out 85 percent of routine capex projects and 66 percent of non routine capex projects. Therefore, the delivery of these forecast projects largely relies on the necessary resources within JAM to project manage the tendered contracts and the availability of parties willing to tender.

JAM has currently approved the addition of one contract manager to provide the additional resource necessary to deliver the 2010-11 capex and opex. JGN is also confident that there are sufficient construction and engineering resources available to deliver the capex program efficiently as displayed by the 23 responses that JAM received to an open tender for the Wakehurst Parkway project.

JGN notes that there is no impact on JAM's ability to deliver projects as a result of increased demands from the electricity industry as the resources to build these projects are gas specific.

3b.4.7 Equity raising costs

JGN does not incorporate the AER's decision and includes equity raising costs in its capital plan. This is because based on new forecast cost of service, equity raising cost assumptions and capital plan, JGN will not be able to cover its equity raising requirements through retained earnings alone.

JGN proposes to capitalise equity raising costs of $3.31 million to its RAB using benchmark costs for an efficient gas network:

- 1 per cent on equity raised internally through dividend reinvestment
- 3 per cent on equity raised externally.

These benchmarks are based on estimates adopted in the AER's draft decision.[127] JGN includes its proposed calculation of equity raising costs in the 'Equity Raising Costs' sheet of appendix 10. It ensures that equity raising costs are capitalised to JGN's opening 2011 RAB if the retained earnings cash flow is not sufficient to cover the equity needed to fund JGN's capital plan.

Equity raising costs are incurred each time equity is raised and may include legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity.

A benchmark efficient gas network can use equity from retained earnings, dividend reinvestment and from external sources to cover the equity cost of its forecast

[127] Draft decision, p. 216.

capex.[128] Generally, using retained earnings is costless, so equity raising costs refers to costs from raising equity using dividend reinvestment or external sources. An efficient gas network business would therefore prefer to use retained earnings first, but if they are not sufficient to cover the equity cost of forecast capex, then a business must raise equity from other more costly sources.

Equity raising costs are affected by other regulatory decisions

In its original proposal JGN estimated that equity raisings costs were immaterial because, given its proposed capital plan, benchmark equity raising costs and forecast cost of service, it forecast that retained earnings would be enough to cover all equity raising requirements. JGN proposed to:

> exclude these costs, but revisit this position if either the forecast cost of service or equity raising cost assumptions changed.[129]

The AER's draft decision changed the forecast cost of service, equity raising cost assumptions and capital plan, but did not revisit whether this resulted in equity raising costs. The AER did not include any equity raising costs because it considered that these costs:

> would not be incurred by a prudent service provider acting efficient, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivery pipeline services as required by r. 91 of the NGR. [130]

The AER based this position on the grounds that JGN's initial proposal did not include equity raising costs. [131]

JGN forecasts that, based on JGN's new proposed cost of service, capital plan and equity raising costs assumptions, an efficient gas business would not be able to meet its equity raising requirements through retained earnings alone. JGN considers that its equity raising costs should be included so long as cell D52 of the 'Equity Raising Costs' sheet of the Appendix 10 remains greater than zero.[132]

JGN considers its proposed equity raising costs are consistent with rule 79. The AER has previously approved equity raising costs for other energy networks.

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128 To maintain constant leverage of 60 per cent JGN must have enough equity to cover the 40 per cent of its forecast capex.

129 JGN original revised AA proposal, 25 August 2009, p. 92–93.

130 Draft decision, p. 216.

131 Draft decision, p. 216.

132 If this amount is less than zero, JGN considers that this amount should not be capitalised to JGN's opening 2011 RAB because it is not sensible to have negative equity raising costs.

4 Depreciation

- JGN has incorporated the depreciation principles that are reflected in the AER's required amendments.
- JGN has not incorporated the AER's amended RAB roll-forward calculation for reasons set out in Chapter 3 of this document.
- Accordingly, JGN has not adopted the AER's amended values for remaining asset lives because those values are necessarily a function of the RAB calculation.

4.1 Summary of JGN original proposal

In its original AA proposal, JGN established a depreciation schedule that it considers reflects the economic lives and cash flow needs of the business consistent with the NGR requirements.

JGN proposed to determine the annual amount of regulatory depreciation for each asset class by applying the real straight-line depreciation method to the opening regulatory value of each asset class for each financial year.

The economic lives provided were the same as those used in JGN's AA for the current AA period, and are consistent with the design lives used by JGN in engineering evaluations.

4.2 Summary of AER draft decision

The AER draft decision generally approves the economic lives and depreciation schedules proposed by JGN. The draft decision also provides that in order to make the proposal acceptable to the AER, JGN would be required to amend the remaining asset lives:

- in a manner that is consistent with its requirement that the RAB roll-forward calculation be amended
- to avoid the situation where the remaining life for an asset class (e.g. motor vehicles) exceeds the economic life for that class.

Table 4-1 sets out the amendments the AER required in its draft decision in relation to depreciation.

Table 4-1: Amendments the AER required in its draft decision – depreciation

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
4.1	Amend AAI to delete Table 10.2 (outlining economic life and remaining life for assets) and replace with the table provided in the draft decision.	Partially incorporated	Section 4.3.1
4.2	Amend AAI to replace column headed "Remaining Asset Life" of Table 10.3 with the table provided in the draft decision.	Partially incorporated	Section 4.3.1

4.3 JGN response to AER draft decision

4.3.1 Remaining asset lives

Following its review of the AER's draft decision, JGN has incorporated the depreciation principles that are reflected in the AER's required amendments. However JGN has not incorporated the AER's amended RAB roll-forward calculation for reasons set out in chapter 3a of this document. Accordingly, JGN has not adopted the AER's amended values for remaining asset lives because those values are necessarily a function of the RAB calculation.

One of the assumptions in the RAB roll-forward calculation relates to capex and the fact that it is spent throughout the year. JGN has assumed that half of each year's capex is spent at the beginning of the year and half at the end. This is the approach taken by IPART, and JGN has maintained this assumption in its revised proposal. As previously stated, no amendment is required to JGN's approach in this regard in order to correct any relevant non-compliance with a provision of the NGR or NGL.

4.4 Amendments to the access arrangement proposal and information

JGN has amended tables 10-2 and 10-3 of the AAI to be consistent with its responses to amendments 4.1 and 4.2.

5 Cost of Capital

- JGN proposes a nominal vanilla cost of capital of 10.86 per cent.
- JGN's cost of capital calculation incorporates many of the AER's amendments, including changing to a post-tax nominal WACC, revised market risk premiums and gearing ratios, and inflation forecasts based on reserve bank targets.
- JGN has retained use of the Fama-French model in its calculation of the cost of equity because it produces a demonstrably better estimate than the Capital Asset Pricing Model. The Fama-French model is a financial model that is well accepted by practitioners and academics. Use by regulators is not a necessary condition for it to be considered well accepted.
- JGN proposes a debt risk premium of 4.48 per cent that is 16 basis points higher than the premium provided in the AER's draft decision.133 This is because a BBB credit rating is more suitable for a benchmark efficient gas business than the BBB+ rating used by the AER, and because JGN proposes and applies a new three-step method for estimating the debt risk premium for a 10 year corporate bond.

5.1 Summary of JGN original proposal

In its original AA proposal, JGN set its cost of capital using a domestic version of the Fama-French three-factor model (**FF model**) to estimate the cost of equity component of its WACC. JGN proposed a pre-tax nominal WACC of 12.63 per cent. This estimate was a placeholder because it was not calculated with reference to the averaging period that will apply for the next AA period.

JGN considered that the use of the FF model to estimate the cost of equity ultimately provides a rate of return that better reflects the prevailing conditions in the market for funds than the Sharpe-Lintner Capital Asset Pricing Model (**CAPM**)[134] as currently applied. Providing a return commensurate with market conditions is required by the NGR and is also critically important to JGN in order for it to be able to fund its required capital program.

JGN's proposed cost of capital reflects the risks of an efficient gas distributor and the prevailing market conditions, as required by the NGR. Importantly, JGN considers that gas distributors are inherently more risky businesses than electricity distributors, with higher debt premia. This view has been supported by the AER in

133 Draft decision, p. 143. The AER sets a debt risk premium of 4.32 per cent, even though p. 140 of the draft decision estimates a debt risk premium of 4.18 per cent.

134 Future references to the CAPM refer to the Sharpe-Lintner version of the model.

previous decisions as well as by other regulators and academics as discussed in detail in section 9.5 of JGN's original AA proposal.

Table 5-1 summarises JGN's proposed WACC parameters (based on a proxy averaging period) and resulting WACC variants as provided in its original AA proposal.

Table 5-1: JGN's proposed WACC Parameters from August 2009 submission

Parameters	JGN Proposal
Inflation (i)	2.38%
Nominal risk-free rate (R_f^n)	5.60%
Real risk-free rate	3.15%
Debt margin (D^n)	5.04%
Nominal pre-tax cost of debt	10.64%
Real pre-tax cost of debt	8.08%
Market risk premium (MRP^n)	6.50%
Growth risk premium (HML^n)	6.24%
Size risk premium (SMB^n)	-1.23%
Equity beta (β_e)	Na
Market beta (β_m)	0.59
Growth beta (β_{HML})	0.48
Size beta (β_{SMB})	0.30
Post-tax nominal return on equity	12.06%
Gearing (D/V)	60%
Dividend imputation (γ)	0.20
Tax rate on equity (T_e)	28.35%
Corporate tax rate (T_c)	30%
Pre-tax real WACC ($WACC^r$)	10.01%

Parameters	JGN Proposal
Pre-tax nominal WACC ($WACC^n$)	**12.63%**
Nominal vanilla WACC	11.21%
Real vanilla WACC	8.63%

Notes:

1. Real costs of debt and equity and the risk-free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.
2. Debt margin is based on an efficient gas business with a BBB credit rating.
3. JGN does not rely on a debt or asset beta to estimate its proposed WACC.

5.2 Summary of AER draft decision

The AER draft decision estimated a nominal vanilla WACC of 10.11 per cent for Jemena. The WACC is 2.52 per cent less than that proposed by JGN in its August 2009 submission. The reason for this difference is that the AER use the Shape-Lintner CAPM[135] for estimating the return of equity instead of the FF model proposed by JGN. The AER draft decision also provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal to incorporate the AER's determination for parameters such as the risk-free rate, equity beta and debt risk premium and these contributed to the lower WACC.

Table 5-2 sets out the amendments that the AER required in its draft decision of JGN's proposed access arrangement in relation to cost of capital.

Table 5-2: Amendments the AER required in its draft decision – cost of capital

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
5.1	Amend the AAI to delete tables 9-1 and 9-4 and replace them with table 5.7 provided in the draft decision	Partially incorporated	Section 5.3
5.2	Make all consequential amendments necessary in the AAI to take account of and reflect amendment 5.1	Partially incorporated	Section 5.3

The AER draft decision considered imputation credits (gamma) in its chapter on taxation. JGN has adopted this approach for the purposes of this section on cost of capital and discusses gamma in chapter 6.

135 In future references to "CAPM" JGN means the Shape-Lintner model.

5.3 JGN response to AER draft decision

Table 5-3 summarises JGN's responses to the AER's draft decision.

Table 5-3: JGN's responses to the AER's draft decision – cost of capital

Change	Related AER amendments	JGN incorporation	Summary of explanation	Explanation in this document
WACC framework	5.1, 5.2	Has partially incorporated	Change to post-tax nominal WACC	Section 5.3.1
Cost of equity (Fama-French)	5.1, 5.2	Has not incorporated	Retained Fama-French model, not CAPM	Section 5.3.2
Risk-free rate	5.1, 5.2	Incorporated	Use an average of observed yields over 20 business days	Section 5.3.4
Equity beta	5.1, 5.2	Has not incorporated	Equity beta not relevant to Fama-French model	Section 5.3.5
Market risk premium	5.1, 5.2	Incorporated	Use market risk premium of 6.5 per cent	Section 5.3.6
Gearing ratio	5.1, 5.2	Incorporated	Use gearing of 0.5	Section 5.3.7
Debt risk premium	5.1, 5.2	Has not incorporated	BBB credit rating more appropriate for gas businesses and Bloomberg data provides better estimate of than CBASpectrum data	Section 5.3.8
Inflation forecast	5.1, 5.2	Incorporated	Use average of RBA target inflation	Section 5.3.9

JGN provides detail on its response to the AER's draft decision below.

5.3.1 Post-tax nominal vanilla WACC

JGN will use a post-tax nominal vanilla WACC to estimate the return on capital building block, rather than a pre-tax nominal WACC as proposed in JGN's original AA proposal. This incorporates the approach set out in the AER's draft decision.

JGN has not revised its proposal to incorporate a gamma estimate of 0.65 as set out in the AER's draft decision, but instead reaffirms its view that a gamma of 0.2 is the best estimate of this parameter in the circumstances for reasons set out in chapter 6 of this document.

The nominal vanilla WACC is calculated as a weighted average of the cost of equity and the cost of debt, with gearing ratios used to weight the calculation. Each element of this calculation is dealt with below.

5.3.2 Rules assessment framework

Rules 74 and 87 of the NGR provide the framework for assessing JGN's proposed parameter for the cost of capital for its proposed AA. Table 5-4 below summarises how these rules apply to the inputs, methodology, and outputs of the cost of capital calculations. We refer back to these rules throughout the body of this chapter.

Table 5-4: Summary of NGR rules that apply to cost of capital

Element	Rule requirements
Outputs	Must be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services (87(1))
	Must represent the best forecast or estimate in the circumstances (74(2)(b))
Methodology	Must assume that the service provider meets benchmark levels of efficiency (87(2)(a)(i))
	Must assume that the service provider uses a financing structure that meets benchmark standards (87(2)(a)(ii))
	Must be a well accepted approach to calculating a rate of return (87(2)(b))
	Must use a well accepted financial model (87(2)(b))
Inputs	Must be supported by a statement of the basis of the forecast or estimate (74(1))
	Must be arrived at on a reasonable basis (74(2)(a))
	Must represent the best forecast or estimate in the circumstances (74(2)(b))
	To the extent that any inputs rely on a particular financial model, this must be a well accepted financial model (87(2)(b))

5.3.3 Cost of equity (Fama-French model)

JGN maintains its position that the Fama-French three factor model (**FF model**) produces the best estimate of the cost of equity possible in the circumstances. The

FF model is a well accepted financial model and it provides a better estimate for a benchmark efficient gas network than the CAPM.

By applying the Fama-French model, JGN proposes a cost of equity estimate of 12.04 per cent. This is based on a risk-free rate estimate of 5.58 per cent and the FF model parameters set out in Table 5-5.[136]

Table 5-5: Proposed parameters for domestic Fama-French three-factor model

Parameters	Market	HML	SMB
Risk Premium	6.50%	6.24%	-1.23%
Beta	0.59	0.48	0.30

Notes: The market risk premium is the value used by the AER for electricity businesses. The other parameters are estimated from data provided by Bloomberg and DFA.[137]

Source: NERA's August 2009 report.[138]

To be accepted as the method for calculating the cost of equity, the FF model must meet the requirements of rules 74 and 87, as shown earlier in this chapter. The rest of this section explains why JGN considers that the FF model satisfies these requirements and is laid out as follows:

- the FF model is a well accepted financial model (rule 87(2)(b))
- the inputs to the FF model are arrived at on a reasonable basis (rule 74(2)(a))

[136] These parameters apply to the FF model which can be expressed by the following formula:

$$\mathrm{E}(R_j) - R_f = b_j[\mathrm{E}(R_m) - R_f] + h_j HML + s_j SMB,$$

where:

E(jj) is the expected return on asset j

R(m) is the expected return to the market portfolio of risky assets

Rf is the risk-free rate

bj, hj and *sj* are the slope coefficients from a multivariate regression of *Rj* on *Rm, HML* and *SMB* and *HMPL* and *SMBP* are the expected values of HML and SMB.

[137] FF model parameters are estimated using data sampled up to the end of May 2009. Where appropriate, NERA has populated the FF model with the same data and parameters as those employed by the AER in its recent review of the WACC parameters for electricity lines businesses. Those parameters not shared with the CAPM have been estimated from data provided by Bloomberg and DFA. DFA is an investment group affiliated with Fama and French that explicitly invests along the lines suggested by their research.

[138] NERA, 12 August 2009, *Cost of Equity – Fama-French Three Factor Model*, report for Jemena Gas Networks (NSW). Appendix 9.1 of JGN's original AA proposal.

- the outputs of the FF model are commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services (rule 87(1))

- the outputs of the FF model represent the best forecast or estimate in the circumstances (rule 74(2)(b))

JGN has critically assessed the AER's draft decision, NERA's August 2009 report and a subsequent March 2010 report from NERA to form its view—see appendices 5.1 and 5.2.[139] In its subsequent report, NERA explains how the inputs to and outputs of the FF model satisfy the requirements of rules 74 and 87.

Fama-French is a well accepted financial model

JGN considers that the FF model is a "well accepted financial model" because, in essence, JGN consider that acceptance by practitioners and academics is sufficient to make it well accepted. In contrast, the AER in its draft decision determined that the FF model is not well accepted because it is not used by regulators in Australia or overseas.

Rule 87(2)(b) requires that a well accepted financial model is used to estimate the cost of equity for a benchmark efficient gas network. JGN considers that this rule requires that the model be well accepted by either regulators, practitioners, academics or other experts. JGN bases its view on the following:

- *'Well accepted' less demanding than 'generally accepted'*—The requirement that a model is 'well accepted' is less demanding than the requirement that the model is universally or 'generally accepted'.

- *Acceptance not required by regulators*—There is no evidence indicating that the phase 'well accepted' requires that a financial model, besides being accepted by academics or practitioners, also be accepted by regulators. There is evidence to the contrary. For example, the Australian Legal Dictionary states that generally accepted accounting principles (**GAAP**) are principles that have "evolved over many years in the accounting profession"[140]. In other words, GAAP are principles and procedures that have gained currency among practitioners rather than regulators or courts. It is difficult to see that the less demanding phrase 'well accepted' used in rule 87(2)(b) would also require that a financial model, besides being accepted by academics or practitioners, also be accepted by regulators.

[139] NERA, *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena. 19 March 2010, Appendix 5.1.

[140] Butterworths, *Butterworths Encyclopaedic Australian Legal Dictionary*, available on a subscription basis at: http://www.lexisnexis.com.au/aus/products/catalog/current_htm/beald%20onl.asp.

- *Inconsistent to require acceptance by regulators*—If, for a financial model to be well accepted, it has to be well accepted by regulators, then it is difficult to see how an alternative model could ever become well accepted. In other words, if a condition for a regulator to use a model were that a regulator use the model, then no model other than those currently in use could ever be adopted—no matter how well accepted by academics and practitioners. Moreover, if the intent of rule 87 was to require that a financial model be well accepted by regulators, then surely the drafters of the rule would have adding the phrase "by regulators" after the phrase "well accepted financial model";

- *More than one well accepted financial model*—The fact that rule 87(2)(b) refers to the CAPM as one example of a well accepted model suggests that other well accepted models exist. If the CAPM were the only well accepted financial model, one would expect that the NGR would prescribe its use. The NGR, though, unlike the national electricity rules[141], explicitly do not prescribe the use of the CAPM. This implies a conscious choice by the drafters of both sets of rules to allow other well accepted financial models under the gas regime.

The AER has taken a narrower view of 'well accepted financial model' than JGN. Moreover, the AER states:

> Since the [FF model] is not well accepted in a regulatory context, the AER considers that this indicates the model is not a well accepted model as required by r. 87 of the NGR. [142]

As noted above, JGN considers that a financial model can still be well accepted as required by rule 87 even if not well accepted by regulators. Moreover, JGN considers that the FF model is well accepted by academics and practitioners and therefore satisfies rule 87.

JGN considers that the FF model is well accepted by academics and practitioners for the following reasons:

- developed by well regarded academics, Eugene Fama and Ken French

- has had favourable media attention in the 'New York Times' and UK's 'The Guardian'

- is one of the most widely cited academic papers

[141] Rule 6.5.2(b) of the national electricity rules: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.

[142] Draft decision, pp. 108–9.

- is support by papers raised in the AER draft decision, including Da, Guo and Jagannathan (2009) and Gharghori, Lee and Veeraghavan (2009)
- is taught at every major Australian university
- *is part of the CFA course* – the Chartered Financial Analyst (**CFA**) course requires all level two candidates to demonstrate the use of the FF model for estimating the required return on an equity investment.[143] The CFA designation is one of the most widely accepted professional qualification for finance practitioners worldwide.[144] The CFA Institute describes the FF model as one of the:[145]
  – "well-established methodologies of security analysis"
  – "major models for estimating the required return on equity"
  – "best known models based on multiple factors"
- has its inputs sold commercially by Morningstar
- is included in McKinsey's guide to valuation.

These and other reasons are explained with references and in more detail in NERA's March 2010 report in Appendix 5.1.

The inputs to the FF model are arrived at on a reasonable basis

The inputs to and outputs of the FF model meet the requirement of rule 74(2)(a) that they are arrived at on a reasonable basis. JGN considers that they meet this requirement for the following reasons:

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143 CFA Institute, 2010, *Equity*, Volume 4 of the Level II CFA curriculum for 2010, p. 101.

144 For example, see:

Investopedia, http://www.investopedia.com/articles/financialcareers/07/different_designations.asp

New York's 'The Sun', http://www.nysun.com/business/while-ivy-league-mbas-impress-hottest-three/42355/

Bloomberg, http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aIKWA1aqm.rs&refer=canada-redirectoldpage

Financial Times, http://www.cfainstitute.org/aboutus/press/mediahighlights/pdf/FT_final.pdf

Professional Exam Review, http://www.professionalexamreview.com/about.php

FTMS Global, http://www.ftmsglobal.com/courses/index.php?option=com_content&view=article&id=20&Itemid=53
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145 CFA Institute, 2010, *Equity*, Volume 4 of the Level II CFA curriculum for 2010, pp. 3, 102 & 130–137.

- a recognised process has been adopted to generate the forecasts and estimates. That process has been properly specified and applied
- the inputs to the model are relevant and current
- to the extent that decisions and choices have been made, there is a logical and cogent basis to support the decision or choice that has been made.

Details on the above reasons are provided in NERA's report in Appendix 5.1.

The outputs of the Fama-French model are commensurate with prevailing market conditions

JGN considers that the FF model's outputs are commensurate with prevailing market conditions because NERA uses recent Australian market data to estimate the FF model parameters in its August 2009 report.

As well as using recent market data, NERA also uses the AER's market risk premium estimate of 6.50 per cent and the AER's approved methodology for estimating the risk free-rate.[146] Therefore, JGN considers that NERA's cost of equity estimate is commensurate with prevailing market conditions.

Also, JGN considers that it would be inconsistent for the AER not to subject both the CAPM and the FF model to the same levels of review in respect to this requirement.

The Fama French model represents the best estimate in the circumstances

The estimate of the cost of equity from the FF model meets the requirements of rule 74(2)(b) as the best estimate in the circumstances. JGN considers that the FF model as applied by NERA provides a better estimate of the cost of equity in the circumstances than the CAPM as applied in the AER draft decision for the following reasons:

- A number of academic papers find that the FF model provides better estimates of the cost of equity than the CAPM in the Australia capital market, including all five of the papers raised by the AER in its draft decision that compare the two models.[147]

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[146] NERA, 12 August 2009, *Cost of Equity – Fama-French Three Factor Model*, report for Jemena Gas Networks (NSW). Appendix 9.1 of JGN's original AA proposal.

NERA, 19 March 2010, *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena.

[147] NERA, 19 March 2010, *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena, section 4.1.

- A number of academic papers also find that the FF model provides better estimates of the cost of equity than the CAPM in the US capital market, including some of the most widely cited papers. [148]

- The FF model and the CAPM both originate from the US capital market.

- The AER applies the theoretical CAPM with restrictions, such as ignoring the fact that large numbers of Australian investors hold foreign assets and hold assets that are not stocks.

- NERA find that the FF model provides a better estimate of the cost of equity for US energy businesses. [149]

These and other reasons are explained with references and in more detail in NERA's March 2010 report in Appendix 5.1.

5.3.4 Risk-free rate

JGN proposes a nominal risk free-rate of 5.58 per cent using the method adopted by the AER in the draft decision. The estimate is based on the 20-day historical average of the annualised yield on 10 year Commonwealth Government Securities (**CGS**) to 12 February 2010 using the indicative mid rates published by the RBA during a period approved by the AER.

JGN estimates the yield on a 10 year CGS maturing at the 20 business days to 12 February 2020 by interpolating on a straight-line basis the yields on the CGS bonds maturing at 15 March 2019 and 15 April 2020. This method is applied in JGN's WACC model (see Appendix 5.3).

JGN considers that this method provides the best estimate in the circumstances as per rule 74(2)(b) and that the resulting estimate—using recent market data—is commensurate with prevailing market conditions as per rule 87(1).

The averaging period used here is for presentational purposes only. JGN will use the averaging period determined in the AER draft decision to estimate the risk free rate using the method above.[150][151] This period differs from the presentational averaging period above. JGN supports the AER's view that this period should remain confidential until after it has passed.

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[148] NERA, 19 March 2010, *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena, section 4.2.

[149] NERA, 19 March 2010, *Jemena Access Arrangement Proposal for the NSW Gas Networks: AER Draft Decision*, a report for Jemena, section 4.3.

[150] Draft decision, Appendix A.

[151] JGN proposes to estimate the debt risk premium over this same period.

5.3.5 *Equity beta*

JGN notes the AER's equity beta estimate of 0.80, but does not incorporate it into the proposed cost of equity. JGN considers that the AER's equity beta estimate is specific to the CAPM used by the AER, which is not relevant to the FF model and JGN's proposed cost of equity.

5.3.6 *Market risk premium*

JGN incorporates the AER's market risk premium (**MRP**) estimate of 6.5 per cent as the best estimate in the circumstances as per rule 74(2)(b).

JGN considers that an MRP of 6.5 per cent reflects the minimum premium that an efficient gas business needs to compensate for the non-diversifiable risk that is influenced by the current financial and economic crises.

5.3.7 *Gearing ratio*

JGN incorporates the AER's gearing ratio of 0.60 as being consistent with rule 87(2)(a)(ii).

JGN considers that a gearing ratio of 0.60 is efficient for a stand-alone gas distribution business and is consistent with JGN's proposed cost of equity and debt risk premium estimates above.

5.3.8 *Debt risk premium*

JGN proposes a debt risk premium of 4.48 per cent for a BBB rated benchmark efficient gas business as the best estimate in the circumstances, satisfying rule 74(2)(b). This margin is added to the nominal risk free-rate estimate of 5.58 per cent to give JGN's proposed cost of debt of 10.06 per cent. JGN has not incorporated the method and assumptions used by the AER in its draft decision to estimate the debt risk premium.

JGN's proposed debt risk premium is a function of two key factors:

- *Credit rating*—JGN reaffirms its proposal that a BBB credit rating is more appropriate for a benchmark efficient gas network than the AER's proposed BBB+ credit rating. JGN does not agree with the AER that electricity and gas businesses are sufficiently close comparators.

- *Method for calculating debt risk premium based on credit rating*—JGN proposes a different method to estimating the debt risk premium based on the BBB credit rating. The method JGN uses is described by PwC in more detail in appendix 5.5.

The rest of this section explains these factors in more detail. It is laid out as follows:

- JGN explains how credit ratings are determined and shows that differences in risks (both systematic and unsystematic) are important.
- JGN shows that by considering electricity businesses a sufficiently close comparator to gas businesses, the AER has asserted that there are no material differences in their risks profiles, despite recognising differences in earlier decisions.
- JGN provides evidence that gas businesses are inherently riskier than electricity gas businesses, in particular by looking at the volatility of annual revenues and the credit ratings of similar businesses.
- JGN describes the key conceptual explanations for the observed differences in risk profiles and credit ratings.
- JGN outlines the method it proposes for calculating the debt risk premium, based on a credit rating, as recommended by PwC.
- JGN proposes a debt risk premium estimate of 4.48 percent using the PwC method that is the best available in the circumstances.

Credit ratings are based on systematic and unsystematic risks

Credit ratings are determined through specialised scoring methodologies employed by credit ratings agencies—such as Standard & Poor's (**S&P**), Moody's Investor Service and Fitch Ratings—to evaluate the systematic and unsystematic risks faced by a particular business. Businesses that have greater risk are generally assigned a lower credit score and therefore a lower credit rating than businesses with lower risk.

Even though many of the risks they evaluate may be considered diversifiable the rating agencies still consider them relevant.[152] For instance, S&P considers the following when assessing risk:[153]

- *Business profile*—a qualitative analysis of a business, including utility type, regulation, markets, operations, competitiveness, and management

[152] Here, JGN distinguishes between (a) systematic or non-diversifiable risk that is relevant for estimating a businesses equity beta and (b) unsystematic or diversifiable risk, which is not relevant. Credit rating agencies consider both (a) and (b) when assessing the credit rating of particular businesses.

[153] Standard and Poor's, September 1998, *Rating Methodology for Global Power Utilities*, Infrastructure Finance, pp 60–73. www2.standardandpoors.com/portal/site/sp/en/eu/page.article/3,2,2,0,1204836260146.html.

- *Financial profile*—a quantitative analysis of a business, including profitability, capital structure, cash flow, and financial flexibility.

Therefore any observed differences in the credit ratings of electricity and gas businesses cannot be attributed solely to different gearing ratios if there is evidence that the risks of the businesses differ. JGN agrees with the AER that "all things being equal, higher gearing ratios should be associated with lower credit ratings",[154] but considers that there are clear differences in the risks of the businesses that will also have an effect on credit rating.

AER has asserted without evidence that there are no material differences in the risks of gas and electricity businesses

The AER states in its draft decision that:

> electricity network businesses are sufficiently close comparators to … estimate the credit rating of a benchmark efficient gas network service provider.[155]

By assuming the same credit ratings for gas and electricity businesses, the AER asserts that the risks of the businesses are not materially different.

The AER has not provided any evidence to support this proposition, despite earlier noting its concerns about using gas network businesses as comparators for electricity network businesses in its draft WACC decision:

> In selecting the sample of comparator [network] businesses the AER agrees … that caution should be taken when including gas [network] businesses into the sample, as gas businesses may have some asset specific characteristics that may impact on the credit rating of gas businesses.[156]

JGN can see no reason why this concern should not apply when selecting comparators for gas network businesses. The AER has also stated in its recent WACC review that:

> [It] has previously acknowledged in its explanatory statement that gas businesses may have a higher business risk than electricity businesses due [to] greater volatility in cash-flows from relatively higher volume risk compared to electricity network businesses.[157]

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154 Draft decision, p. 136.

155 Draft decision, p. 136.

156 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*, December 2008, Table 9.3, p. 264.

157 AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*, 1 May 2009, p. 108.

There is evidence that the risks are materially different

There are two key pieces of evidence that show that the risks of gas businesses are materially different from electricity businesses.

- the annual revenues of gas businesses tend to be more volatile than those of electricity businesses in Australia
- the credit ratings of gas businesses tend to be lower than comparable electricity businesses in Australia

Table 5-6 below summarises a high level analysis of the volatility of revenues, where volatility is calculated as the standard deviation in the growth of annual revenues. For a sample of 12 gas and electricity business, the average standard deviation of gas businesses is 0.8 per cent higher than that of electricity businesses. Full details of this analysis are provided in Appendix 5.4.

Table 5-6: Volatility of gas and electricity businesses in Australia

Business	Sector	Geographic Area	Mean of revenue growth	Standard deviation of revenue growth
EnergyAustralia	Electricity	New South Wales, ACT, Victoria and Queensland	6.18%	4.54%
UED	Electricity	Victoria	0.99%	4.46%
SPAusnet	Electricity	Victoria	5.61%	2.31%
CitiPower and Powercor	Electricity	Victoria	3.73%	8.11%
ETSA	Electricity	South Australia	4.91%	1.68%
ElectraNet SA	Electricity	South Australia	8.29%	8.44%
Average (electricity)			*4.95%*	*4.93%*
JGN	Gas	New South Wales	1.18%	4.02%
Multinet Gas	Gas	Victoria	3.94%	3.95%
SPAusnet	Gas	Victoria	7.28%	7.78%
Envestra	Gas	Victoria and New South Wales	3.29%	5.25%
Envestra	Gas	South Australia	5.99%	8.94%
Envestra	Gas	Queensland	9.01%	4.37%
Average (gas)			5.11%	5.72%

Business	Sector	Geographic Area	Mean of revenue growth	Standard deviation of revenue growth
Difference between averages (gas - electricity)			0.16%	0.80%

Source: Annual financial statements and annual reports of gas and electricity businesses.

JGN recognises the above analysis is high-level and is not based on a large data set, but alongside other evidence it presents a convincing argument that the market risks for gas businesses are materially higher than for electricity businesses because they can be less certain about incoming cash flows. In contrast, the AER has not provided any factual evidence to support its opposing assertion.

The credit ratings of two energy businesses in Australia—United Energy Distribution (**UED**) and Multinet—also provide evidence that gas businesses are inherently riskier and that this leads to lower credit ratings. These businesses are worth examining because they are both majority owned by the Diversified Utilities and Energy Trust (**DUET**) Group and therefore any difference in credit ratings is unlikely to be explained by ownership structure.

Table 5-7 shows the credit ratings of these two businesses.

Table 5-7: Credit ratings of DUET owned gas and electricity businesses

Business	Sector	Geographic market	Gearing[158]	Credit rating
UED	Electricity distribution	Victoria	104.92%	BBB
Multinet Gas	Gas distribution	Victoria	90.82%	BBB-

The table above shows that Multinet Gas has a credit rating of BBB- while UED has a credit rating of BBB. This is evidence that gas businesses are inherently riskier and that this difference is sufficient to warrant a lower credit rating. It is difficult to imagine any other factors affecting the credit rating because:

- both business have the very similar ownership and the same management
- both businesses operate in Victoria
- the gearing of UED is higher than that of Multinet Gas.

158 JGN calculates gearing as total liabilities divided by total assets from UED and Multinet Gas's financial statements submitted to the Australia Securities and Investments Commission. UED's gearing is greater than 100 per cent due to a loss on reserves and therefore negative shareholder equity.

All else being equal, UED being more highly geared would typically lead to a lower credit rating. As its credit rating is actually higher, one can reasonably conclude that it is the nature of UED's business—electricity rather than gas distribution—that enables it to have a higher credit rating than Multinet Gas.

Data cited by the AER supports this conclusion. In its draft WACC decision, the AER states:

> The AER acknowledges that gas network businesses with similar financial credit metrics to electricity network businesses may have lower credit ratings.[159]

There are strong conceptual reasons why observed risks and credit ratings will differ for gas businesses

The evidence that gas businesses have higher risk and lower credit ratings than electricity businesses can be explained by the differences in the following factors:

- regulation
- market or volume volatility
- competitiveness.

JGN explains each of these factors in more detail below.

Regulation

Regulation is clearly one of the most important factors influencing the riskiness of network businesses. S&P notes that:[160]

> [E]valuation of regulation also encompasses the administrative, judicial, and legislative processes involved in local or national regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales.

JGN considers that it is crucial to consider any regulatory differences between gas and electricity networks when comparing riskiness. For instance, the type of revenue regulation, whether price cap or revenue cap, affects the risk exposure of regulated network businesses.

Regulation is particularly important given that the AER relies on the BBB+ credit rating of a single electricity network—ElectraNet SA —to determine the credit

[159] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Final Decision,* May 2009, p. 371.

[160] Standard and Poor's, September 1998, *Rating Methodology for Global Power Utilities*, Infrastructure Finance, pp 66.

rating for benchmark electricity networks in the WACC review.[161] The AER then relies on the same electricity network to determine the BBB+ credit rating for a benchmark efficient gas network in its draft decision.[162] ElectraNet SA, as an electricity transmission business, is regulated under a revenue cap regime. In contrast, gas businesses are regulated under a price cap regime, which makes them more vulnerable to volume risk. JGN considers that the difference in regulatory regimes makes an electricity transmission business a poor benchmark for setting the benchmark credit rating of gas businesses.

Market or volume risk

When assessing distribution networks, S&P includes analysis of the risks associated with the market the network sells into. S&P state:[163]

> Assessing a distributor's markets begins with the economic and demographic evaluation of the area in which distribution services are provided. Strength of long-term demand is examined from a macroeconomic perspective, which enables Standard & Poor's to measure trends in investment, income, and employment as indicators of economic change within the service area. The sustainability of increasing demand also is analyzed. Many emerging economies go through periods of very rapid growth followed by severe contractions. This volatility can contribute to significant and unhealthy swings in a utility's revenues.

Market risk is faced acutely by gas networks because unlike electricity networks, gas networks have not saturated potential markets. As a consequence, gas networks have more options to expand their networks to enable new but uncertain demand to connect. For instance, JGN still has room to expand its network into large areas of Sydney and rural NSW, but whether or not it should is affected by uncertain long-term demand from those areas.

A further market factor affecting residential demand is the local climate, which in coastal NSW is relatively benign. Because gas is primarily used by residences for cooking and heating—either space or water—it is particularly susceptible to variation in the weather. Electricity on the other hand has many other uses, which means that a smaller proportion of residential demand is affected by weather. Further, when weather causes electricity networks to lose demand for heating in summer they tend to gain some offsetting demand for air conditioning in winter, and vice versa. In contrast, gas networks do not have offsetting demand in summer because gas does not have a viable cooling application.

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161 Draft decision, p. 136.

162 Draft decision, p. 136.

163 Standard and Poor's, September 1998, *Rating Methodology for Global Power Utilities*, Infrastructure Finance, pp 67.

Hence, because credit rating agencies consider both business specific risk and systematic (or market wide) risk when assigning credit ratings, JGN considers that credit rating agencies will tend to assign lower credit ratings to gas networks—because of their higher volume risk—than electricity networks.

Competitiveness

Exposure to competition is also a major risk factor. S&P states:

> Transmission and distribution utilities face competitive pressures in the form of substitute energy sources and customer self-generation and bypass. Electricity competes with other fuels such as natural gas for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient transmission or distribution service, or more likely caused by a high supply cost component, are cause for concern if customers have alternate energy sources. Self-generation has for many years been a significant risk, as large commercial and industrial customers have taken advantage of cogeneration technologies to reduce their reliance on and, in some cases, disconnect from transmission and distribution systems. [164]

Due to gas's rather limited residential application to cooking, and space and water heating it faces higher demand risk resulting from competition than electricity. This occurs because:

- *Gas competes with electricity for all of its applications*—Electricity can substitute for virtually all gas applications, but the reverse is not true. Consequently, demand for gas is likely to be more elastic.

- *Gas is more exposed to competition from self generation*—Self generation is a risk to all energy distributors. However, because several self generation technologies are aimed specifically at heating (e.g. solar water heating and insulation) gas distributors face an increased threat from self generation.

Method for calculating the debt risk premium

To estimate the debt risk premium for a benchmark efficient gas network business, JGN considers that:

- a benchmark cost of debt should be commensurate with prevailing market conditions and the best estimate in the circumstances, as per rules 87(1) and 74(2), by relying on observed marketing data

- all data sources should be properly tested before being relied upon to estimate a debt risk premium.

[164] Standard and Poor's, September 1998, *Rating Methodology for Global Power Utilities*, Infrastructure Finance, pp 68.

The two main data sources available in Australia come from two information services—Bloomberg and CBASpectrum.[165]

In its draft decision, the AER found that CBA Spectrum's BBB+ fair value curve results in the best estimate possible in the circumstances and used this curve to estimate the debt risk premium of 4.18 for a 10 year BBB+ corporate bond over the 20 business days to 23 December 2009.[166] To support this finding, the AER relied on analysis undertaken for the ActewAGL draft decision that compared the Bloomberg and CBASpectrum services.[167]

But, JGN considers that the AER's analysis does not provided sufficient evidence to support this finding because the analysis.

- only tested the accuracy of the CBASpectrum and Bloomberg fair value curves over the 20 business days to 23 October 2009 (the ActewAGL proxy averaging period), [168] so cannot, without further analysis, support the finding that CBASpectrum fair value curve provides a better estimate over the 20 business days to 23 December 2009 (the JGN proxy averaging period)

- only tested BBB+ bonds with a maximum maturity of 5.6 years against the CBASpectrum BBB+ fair value curve, [169] so cannot, without further analysis, support the finding that this curve provides the best estimate for bonds with a maturity of 10 years.

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165 In its draft decision, the AER rejected JGN's original proposal to use the Tabcorp bond to estimate the debt risk premium because it is only a single bond, which requires several adjustments to make it comparable to the benchmark corporate bond.

See Draft Decision, p. 137–140.

In principle, JGN agrees that the benchmark debt risk premium should reflect the characteristics of a benchmark gas network business and not the characteristics of a single bond issue. At the time of its August 2009 proposal, JGN considered that Bloomberg and CBASpectrum services did not reflect the prevailing conditions in the market for funds because of uncertainty in the debt markets, but considered that most recent bond issue—the Tabcorp April 2009 issue—did reflect these conditions. Since August 2009, this uncertainty has reduced and so JGN considers that Bloomberg and CBASpectrum services better reflect the prevailing conditions in the market for funds.

166 Draft decision, p. 140.

167 Draft decision, p.139.

168 Draft decision, pp.139–140.

AER, *November 2009,* Draft decision: ActewAGL distr bution access arrangement proposal, November 2009 and AER, Draft decision: County Energy access arrangement proposal, section B.4.

169 AER, *November 2009,* Draft decision: ActewAGL distr bution access arrangement proposal, November 2009 and AER, Draft decision: County Energy access arrangement proposal, section B.4. The AER excludes the BBI bond from its sample, which has a 6.5 year maturity.

JGN engaged PwC to review the AER's draft decision on debt margin and propose a method for estimating the debt risk premium for a benchmark efficient gas network business—see Appendix 5.5.[170]

PwC find that the method used by the AER for the JGN draft decision and applied to the JGN proxy averaging period contained many flaws. In particular, PwC find that the AER did not: [171]

- undertake a sensitivity analysis of the estimation errors produced by adopting CBASpectrum or Bloomberg's fair value curve
- test the representativeness of the data that was used by CBA Spectrum to extrapolate its fair value (and debt margin) curves to 10 years
- assess whether the results of CBASpectrum's extrapolation methodology (i.e. the slope of the debt margin curves by credit rating) are consistent with economic theory.

PwC conclude that the AER's estimated 10 year BBB+ debt margin of 4.18 per cent was not the best forecast possible at the time of the JGN draft decision because CBASpectrum's:[172]

- yield estimates were not representative of general financial market opinion in most off the credit rating categories, except for BBB+
- fair value yield curves are uniformly concave across all credit ratings, which contravenes the predictions of economic theory that indicate a linear functional form;
- yield margin curves all have similar slopes, which is not consistent with the predictions of economic theory that the slope withy term should higher for lower rated bonds.

JGN considers that any analysis of the services should (a) be relevant to the period in question and (b) consider the best estimate for 10 year bonds.

So, based on the PwC advice, JGN proposes a three-step method for estimating the debt risk premium for a benchmark efficient gas network business that addresses the flaws identified with the AER's analysis.

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170 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*.

171 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, section 4.4.

172 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, section 4.3.

- *Step one: test the Bloomberg and CBASpectrum services in isolation*—test whether the bond yield estimates that are produced by these services are likely to represent prevailing conditions in the market for funds.

- *Step two: assess the relative merits of Bloomberg and CBASpectrum services*—assess which service provides the best estimate of the debt risk premium for a 10 year BBB bond possible in the circumstances by answering the following two questions:

  – which service provides the better explanation of the yields on the bonds that are on issue?

  – what is the most appropriate method for extrapolating yield estimates for bonds with maturities longer than the bonds that are on issue?

- *Step three: estimate the debt risk premium using the preferred service*—estimate the yield on 10 year BBB rated bonds by:

  – *if CBASpectrum is preferred*, using the fair value yield for 10 year BBB corporate bonds

  – *if Bloomberg is preferred*, extrapolating on a linear basis the fair value yields on five and seven year BBB rated bonds.[173]

Under step one, JGN proposes three tests of the Bloomberg and CBASpectrum services:

1. *Divergence in bank opinions*—does the coefficient of variation of bank feeds into Bloomberg for the Australian corporate bonds of greater than three years duration that are considered for Bloomberg's fair value curve exceed 0.05?

2. *Divergence of fair value yield from the bank opinions*—does the average value of the difference between Bloomberg or CBA Spectrum yield estimate and the mean of bank feeds for the Australian corporate bonds, expressed as a percentage of the yield, exceed +/- 2.50 percent?

3. *Divergence of fair value curve from yield estimates*—does the average value of the difference between Bloomberg's (CBA Spectrum's) fair value

[173] Here, the debt margin on 10 year bonds is calculated as follows:

$$\text{DebtMargin}_{10yr} = \frac{\text{DebtMargin}_{7yr} - \text{DebtMargin}_{5yr}}{2/3} + \text{DebtMargin}_{7yr}\,.$$

curve and the Bloomberg (CBA Spectrum) bond yield estimate, expressed as a percentage of the bond yield estimate exceed +/- 4.00 percent?

Under step two, JGN proposes to compare the (simple) average error associated with each service, consistent with the practice of regulators and advisor's prior to the global financial crisis.[174] Also, JGN agrees with PwC's conclusions that: [175]

- theory predicts that the relationship between the debt margin and term should be approximately linear, at least once short dated bonds are eliminated from the sample of bonds used to estimate fair value yields
- the slope of this relationship should rise as the credit rating declines.

Appendix 5.5 provides further description of the PwC methodology and analysis of the AER draft decision.

The best estimate of the debt risk premium in the circumstances is 4.48 per cent

JGN proposes to apply the three-step method to the 20 business days to 12 February 2010 to determine the best estimate of the debt risk premium in the circumstances, for presentational purposes. This is the same period used to estimate the risk free rate above.

PwC applied the three-step method to the period and concluded that the Bloomberg service provides the best estimate in the circumstances.[176] In particular, PwC find that at longer terms the Bloomberg fair value curve has a better alignment with the data than the CBASpectrum curve.[177] PwC find that:

> CBASpectrum's fair value curves produce debt margins that are materially concave (in contrast to the predictions of economic theory) and rely upon inputs that are not representative of the views across financial institutions. Accordingly, even if CBASpectrum predicted the current bond yields accurately, we consider that the extrapolation that it performs means that its estimate of the margin on 10 year BBB+ debt would not be the best estimate of that margin in the market for funds.[178]

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174 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, p. 10.

175 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, section 3.4.2.

176 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, p. 47.

177 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, p. 51.

178 PriceWaterhouseCoopers, March 2010, *Jemena Gas Networks (NSW), The cost of debt for a gas distributor*, p. 50.

Moreover, PwC find that Bloomberg's fair value curves passed all of the tests of representativeness of the current market for funds.

Over the 20 business days to 12 February 2010, PwC estimate a debt premium of 4.48 per cent on BBB and BBB+ rated bonds using the Bloomberg service as follows:

Table 5-8: JGN's proposed debt premium

Details	Average yield / margin
Yield on five year BBB rated bonds	8.75%
Yield on five year CGS	5.24%
Debt margin on five year BBB rated bonds	3.52%
Yield on seven year BBB rated bonds	9.33%
Yield on seven year CGS	5.43%
Debt margin on seven year BBB rated bonds	3.90%
Proposed debt margin on 10 year BBB rated bonds	4.48%

JGN recognises that its proposed debt margin will require updating for the final averaging period. On this basis, JGN submits the method contained in Appendix 5.5 for approval.

5.3.9 Forecast inflation

Following its review of the AER's draft decision, JGN proposes an inflation forecast of 2.52 per cent, incorporating the method used by the AER in its draft decision as the best estimate in the circumstances, as per rule 74(2)(b).

Accordingly, JGN estimates forecast inflation as the geometric average of the forecast annual inflation for each of the ten years from 2011 to 2020 as follows:

Table 5-9: Forecast Inflation

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Forecast	2.50%	2.75%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Geometric Average										**2.52%**

Note: Inflation forecasts are for the year to June.

Source: Reserve Bank of Australia, Statement on Monetary Policy, 4 February 2010, page 58, table 12.

Our explanation of the ten annual inflation forecasts above are as follows:

- *first two years* – the forecasts are the expected inflation outcomes stated in the Reserve Bank of Australia's (RBA's) most recent Statement on Monetary Policy

- *subsequent eight years* – the forecasts are the midpoint of the RBA's long term inflation target range. The forecast range is 2 to 3 per cent, so the midpoint is 2.50 per cent.

This approach is consistent with the AER's approach in the draft decision and the recent price determinations for NSW and ACT electricity distributors.

5.4 Amendments to the access arrangement proposal and information

JGN proposes to amend its access arrangement information to delete Tables 9-1 and 9-4 and replace both of them with the following table:

Table 5-10: JGN's proposed WACC Parameters for revised submission

Parameters	JGN Proposal
Inflation (i)	2.52%
Nominal risk-free rate (R_f^n)	5.58%
Real risk –free rate	2.98%
Debt margin (D^n)	4.48%
Nominal pre-tax cost of debt	10.06%
Real pre-tax cost of debt	7.36%
Market risk premium (MRP^n)	6.50%
Growth risk premium (HML^n)	6.24%
Size risk premium (SMB^n)	-1.23%
Equity beta (β_e)	Na
Market beta (β_m)	0.59
Growth beta (β_{HML})	0.48
Size beta (β_{SMB})	0.30
Post-tax nominal return on equity	12.04%

Parameters	JGN Proposal
Gearing (D/V)	60%
Nominal vanilla WACC	**10.86%**
Real vanilla WACC	8.13%

Notes:

1. Real costs of debt and equity and the risk free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.
2. Debt margin is based on an efficient gas business with a BBB credit rating.
3. JGN does not rely on a debt or asset beta to estimate its proposed WACC.

6 Taxation

- JGN has incorporated the AER's decision and applied a post-tax approach to calculating required revenues.
- JGN applies the diminishing value depreciation method to calculate its tax asset base because it is the approach JGN has elected (with the ATO) to use to calculate its actual tax liability and is consistent with other regulatory decisions and the requirements of the NGL and NGR.
- JGN uses an assumed utilisation of imputation credits (gamma) of 0.2 because it is a better estimate than the AER's for two reasons—the AER's payout ratio of 1 is not backed by empirical evidence and JGN's 0.23 estimate of theta is the best available estimate based on recent data.

6.1 Summary of JGN original proposal

JGN elected to determine its building block revenue using a pre-tax approach as provided for under rule 72(1)(h) of the NGR in its August 2009 proposal. This is consistent with IPART's method for compensating for taxation costs used in JGN's last three AA periods by applying a pre-tax rate of return to the value of assets when determining JGN's revenue requirement.

JGN's proposed pre-tax approach means that the rate of return used to determine the return on capital is a pre-tax rate of return. This meant that it was not necessary for JGN to itemise the estimated annual cost of corporate income tax as a separate building block as required by rule 76(c). Instead, JGN converted its proposed nominal vanilla rate of return to a pre-tax rate of return using an estimate effective tax rate of 28.35 per cent as discussed in section 9.7.8 of JGN's August 2009 submission.

JGN calculated an effective tax rate in line with the AER's AA guideline.[179]

In its original AA proposal, JGN proposed a value of imputation credits (or gamma) of 0.2[180].

179 AER, *Access arrangement guideline, Final*, March 2009, p. 62.

180 The draft decision considered imputation credits (gamma) in the taxation chapter. Accordingly, gamma is addressed in this chapter of the submission.

6.2 Summary of AER draft decision

The AER draft decision considered that, in order to make JGN's proposal acceptable to the AER, JGN should amend its proposal to include a post-tax approach for taxation.

Accordingly, the draft decision did not propose to approve the approach to establishing compensation for taxation and opening taxation asset base proposed by JGN[181]. The draft decision considered that in moving to a post-tax approach, JGN should incorporate a value for gamma in calculating a taxation building block. The draft decision required JGN to amend gamma to 0.65[182].

Table 6-1 sets out the amendments that the AER required in its draft decision of JGN's proposed access arrangement in relation to taxation.

Table 6-1: Amendments the AER required in its draft decision – taxation

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
6.1	Amend the AAI to delete the sections of 9.4 relating to a pre-tax approach and replace them with the following: JGN determines its building block requirement using a post-taxation approach. It is therefore necessary to itemise "the estimated cost of corporate income taxation for [each] year" as a separate revenue building block consistent with rule 76(c)	Incorporated	Section 6.3.1
6.2	Amend section 9.4 in the AAI to include a discussion of the estimation of the taxation building block, i.e. using a post-taxation framework, including a reference to appendix 9.3 of the AAI	Incorporated	Section 6.3.1
6.3	Amend the AAI to delete section 9.6.1 (WACC proposal) and replace it with the WACC proposal provided in the draft decision	Not incorporated	Section 6.3.1
6.4	Amend the AAI to delete section 9.7.8 (tax rate on equity)	Incorporated	Section 6.3.1

181 Draft decision, p. 160.

182 ibid.

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
6.5	Amend the AAI to change the title of appendix 9.3 to “taxation asset base”	Incorporated	Section 6.3.1
6.6	Amend the AAI to delete section 1 and the introduction to section 2 in appendix 9.3 (Effective tax rate)	Incorporated	Section 6.3.1
6.7	Amend the AAI to delete the third dot point in section 2.2 in appendix 9.3 (Effective tax rate) and replace it with the following: To determine the taxation written down value of each asset and hence the opening tax asset base for the regulatory capital base assets as at 1 July 1999. Where the taxation regime offered the option of prime cost (historic straight line) or diminishing value depreciation. JGN has used the prime cost method. The prime cost method was used to ensure consistency with approaches to taxation in past access arrangement periods.	Not incorporated	Section 6.3.2
6.8	Amend the AAI to delete table 2-1 (JGN opening TAB) in appendix 9.3 (Effective tax rate) and replace it with the provided table, after calculating the initial taxation life and remaining taxation life.	Incorporated	Section 6.3.2
6.9	Amend the AAI to delete table 2-2 (TAB roll forward from 1999-2010) in appendix 9.3 (Effective tax rate) and replace it with the provided table	Not incorporated	Section 6.3.2
6.10	Amend the AAI to delete table 2-3 (TAB roll forward from 2011-2015) in appendix 9.3 (Effective tax rate) and replace it with the provided table	Not incorporated	Section 6.3.2
6.11	Amend the AAI to delete table 2-4 (Roll forward of TAB from 2011-2015) in appendix 9.3 (Effective tax rate) and replace it with the provided table	Not incorporated	Section 6.3.2
6.12	Amend the AAI to delete all references to a gamma value of 0.2 and replace them with 0.65	Not incorporated	Section 6.3.4

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
6.13	Make all consequential amendments necessary to take account of and reflect amendments 6.1 to 6.12 including updating modelling inputs and calculations	Partially incorporated	Section 6.3.1, Section 6.3.2, Section 6.3.4

6.3 JGN response to AER draft decision

Table 6-2 summarises JGN's responses to the AER's draft decision.

Table 6-2: JGN's responses to the AER's draft decision – taxation

Change	Related AER amendments	JGN revised AA revision	Summary of explanation	Explanation in this document
Pre tax and post tax frameworks	6.1, 6.2, 6.3, 6.4, 6.5, 6.6, 6.13	Incorporated	Changed to post tax approach to calculating required revenue	Section 6.3.1
Depreciation to determine the tax asset base	6.7, 6.8, 6.9, 6.10, 6.11, 6.13	Not incorporated	Use diminishing value depreciation to calculate the opening 2011 tax asset base	Section 6.3.2
Assumed utilisation of imputation credits (gamma)	6.12, 6.13	Not incorporated	Gamma of 0.2 is a better estimate because (a) the AER's payout ratio of 1 is not backed by empirical evidence and (b) a 0.23 estimate of theta is the best available estimate based on recent data	Section 6.3.4

JGN provides detail on its response to the AER's draft decision below.

6.3.1 *Pre tax and post tax frameworks*

JGN proposes to calculate its revenue requirement on a post tax basis. This incorporates the approach set out in the AER's draft decision, although JGN does not necessarily accept the reasons given by the AER for requiring this amendment.

The post-tax approach involves incorporating a separate taxation building block—the estimated cost of corporate income tax (ETC)—which is calculated for each year as:

$$ETC = (ETI \times r)*(1 - \gamma)$$

where:

ETI is the estimate of taxable income for that year

r is the tax rate; and

γ is the assumed utilisation of imputation credits, which is the product of the payout ratio and the utilisation rate (θ).

6.3.2 *Rules assessment framework*

Rule 74 of the NGR requires that forecasts and estimates be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances. Any estimate of the cost of corporate income tax must conform with this rule requirement and must also be supported by a statement of the basis of that forecast or estimate (NGR, rule 74(1)). In the remainder of this section, we explain how the JGN approach to estimating the cost of corporate income tax conforms with these rule requirements.

6.3.3 *The depreciation method used to determine the tax asset base – amendment 6.7*

JGN proposes to use diminishing value tax depreciation to estimate the opening tax asset base (**TAB**) because this method aligns with JGN's election to use diminishing value tax depreciation when determining its tax liability with the Australian Tax Office (**ATO**).

JGN has not incorporated the AER's requirement to use the prime cost (historic cost straight line) depreciation method (amendment 6.7). JGN's reasons for taking this position are set out below under the following headings:

- tax depreciation should be based on the efficient costs of providing reference services

- tax depreciation should be based on the approach used to calculate JGN's actual tax liability

- the AER has concluded, based on an earlier IPART decision, that a uniform tax rate implies straight line depreciation method

- IPART's reasoning does not support the AER's conclusion

- the AER's reasoning appears to be incorrect and is not supported by any analysis

- depreciation methods should be consistent across regulatory periods.

Tax depreciation should be based on the efficient costs of providing reference services

Tax is a cost for a benchmark efficient gas business and tax depreciation affects this cost. JGN considers that Rule 74(2) requires that compensation for tax be the best estimate, in the circumstances, of the efficient cost of providing reference services.

Therefore, to estimate this efficient cost, the TAB should be a realistic estimate of the tax position of an efficient gas business in the circumstances. JGN considers that these circumstances include:

- JGN's historic nominal capital expenditure

- the tax law existing at the time of this expenditure

- the assumed tax depreciation method that an efficient gas business would have elected to use if it operated JGN's network historically.

JGN proposes to use its actual historic capital expenditure, the tax rates applying when this expenditure was incurred and, as an assumption, diminishing value tax depreciation to calculate its opening 2010-11 TAB.

JGN considers that its actual tax depreciation method—diminishing value, as discussed below—provides the best indication of the method that an efficient gas business would take in the circumstances.

Other regulatory decisions have also adopted diminishing value tax depreciation. For instance, the ESC in its 2008 GAAR final decision adopted this method,[183] while considering that:

[183] ESC, 7 March 2008, *Gas Access Arrangement Review 2008-2012*, Final Decision, p. 498. Noting that the ESC adopted the tax depreciation method consistent with the 2003 Gas Access Arrangement review, which was to use diminishing value tax depreciation.

> the process of deriving an allowance for the cost of tax is not a matter for discretion, but rather that the Code requires that the Commission establish the best estimate of the cost, arrived at on a reasonable basis in accordance with section 8.2(e). To derive such an estimate, account must be taken of the implications of the tax law for the distributors' tax depreciation allowances.[184]

Although this decision was made in the context of the Gas Code, section 8.2(e) of the Code corresponds directly with Rule 74(2). Section 8.2(e) requires that "any forecasts required in setting the Reference Tariff represent the best estimates arrived at on a reasonable basis".[185] JGN agrees with the ESC's interpretation of section 8.2(e) and considers that this interpretation applies equally to Rule 74(2).

Further, in an electricity context, the ESC also approved diminishing value tax depreciation in the 2006 EDPR final decision.[186]

Tax depreciation should be based on the approach used to calculate JGN's actual tax liability

JGN has elected diminishing value depreciation for the bulk of its assets in determining its tax liability with the ATO. This provides a compelling basis for assuming diminishing value tax depreciation in determining JGN's opening tax asset base for the 2010-11 regulatory year for an efficient gas network business in the circumstances.

The AER has concluded that a uniform tax rate implies straight line tax depreciation

The AER's requirement that JGN should use nominal straight line tax depreciation in calculating the 1999 opening tax asset base and in rolling that value forward to the start of the 2010-11 regulatory year is based on its interpretation of previous IPART decisions.

In grossing up from a post-tax WACC to a pre-tax WACC in its 2000 and 2005 decisions, IPART assumed the statutory tax rate of 30 per cent in both decisions. The AER has interpreted these decisions as follows:

> [the assumption, by IPART, of] a uniform taxation rate over different access arrangement periods necessarily implies the use of straight line [tax] depreciation method.[187]

See ESC, October 2002, *Gas Access Arrangement Review 2003-2008*, Final Decision, pp. 379–390.

184 ESC, 7 March 2008, *Gas Access Arrangement Review 2008-2012*, Final Decision, p. 498.

185 *National Third Party Access Code for Natural Gas Pipeline Systems*, section 8.2(e).

186 ESC, October 2005, *Electricity Distribution Price Review 2006-10*, Final Decision Volume 1, pp. 551–554. Here, the ESC refers to 'diminishing value' tax depreciation as 'declining balance' tax depreciation.

IPART's reasoning does not support the AER's conclusion

IPART's reasoning does not support any inference about the form of tax depreciation that should be used in establishing the tax asset base.

In its 2000 Final Decision, IPART adopted the statutory rate of 30 per cent stating that "In the draft decision the Tribunal decided that the statutory tax rate would be applied due to difficulties in estimating the effective tax rate for the industry as a whole. The Tribunal maintains this view".[188]

In adopting the statutory rate of 30 per cent in its 2005 Final Decision, IPART's reason was simply that "The Tribunal is satisfied that the use of the statutory tax rate of 30 per cent proposed by AGLGN meets the requirements of section 8.30 of the Code".[189]

The AER's reasoning appears to be incorrect and is not supported by any analysis

The AER suggests that IPART's assumption of the same 30 per cent tax rate for two consecutive regulatory periods implies straight line tax depreciation.[190] This reasoning appears incorrect and the AER does not provide any analysis to support it.

The effective tax rates in different periods will only be the same if regulatory depreciation (the depreciation amount used to set revenues) is equal to tax depreciation (the depreciation amount used to calculate taxes) in each year of each period.[191] This condition is demonstrated in Appendix 6.2. This condition has not and will not be met for JGN because:

- *regulatory versus tax depreciation method* – Regulatory depreciation is based on *real* straight line depreciation whereas the prime cost option for tax depreciation uses *nominal/historic cost* straight line depreciation. Even if the prime cost method was used for tax depreciation, the annual regulatory and tax depreciation amounts will be materially different.

- *regulatory versus tax depreciation lives* – Standard regulatory asset lives (used to calculate regulatory depreciation) and effective lives (used to

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187 Draft decision, p. 149.

188 IPART, *Final Decision, Access Arrangement For AGL Gas Networks Limited Natural Gas System In NSW*, July 2000, p. 66.

189 IPART, *Revised Access Arrangement for AGL Gas Networks, Final Decision*, April 2005, p. 82.

190 Draft decision, p. 149, and confirmed by the AER in AER, 2010 03 11 – Letter AER to JGN – Errors in draft decision, 11 March, 2010, Item 15 under the heading 'Clarification of AER's reasons for draft decision: (8 March 2010, 3 page letter).

191 There may be cases where the combination of post tax returns on equity and different depreciation schedules is such that different periods have the same effective tax rates, but those cases will be rare in practice.

calculate tax depreciation) are not necessarily the same. For example, the effective life of pipeline infrastructure for tax purposes is 30 or 50 years depending on material[192] whereas the regulatory life is normally 50 or 80 years depending on material. In fact the actual amount of tax depreciation allowed under the diminishing value method is calculated as if the effective life was two thirds or half of the "headline" effective life by virtue of sections 40.70 and 40.72 of the Income Tax Assessment Act 1997.[193] Again, the annual regulatory and tax depreciation amounts will be materially different even if the methods were the same.

Depreciation methods should be consistent between regulatory periods

JGN considers that the tax depreciation method used to roll-forward the 2010-11 opening tax asset base in the next regulatory period should be the same as the method used to establish the opening TAB for the 2010-11 regulatory year. Accordingly, JGN also proposes to use the diminishing value tax depreciation method for the next regulatory period. JGN calculates the opening TAB for the 2010-11 regulatory year in Appendix 6.1 and calculates tax depreciation for the next regulatory period in Appendix 10.

If the AER determines to use nominal straight line tax depreciation to establish the opening taxation asset base for the 2011 regulatory year, then JGN proposes to use nominal straight line tax depreciation for the next regulatory period also.

6.3.4 Value of imputation or franking credits (gamma)

JGN has not incorporated the AER's gamma estimate of 0.65. JGN proposes a gamma estimate of 0.2 because it the best estimate in the circumstances, relying on evidence presented in Appendix 6.3.

The rest of this section explains why JGN considers a gamma of 0.2 a better estimate than 0.65 and is laid out as follows:

- JGN and AER agree on a definition of gamma
- the AER's imputation credit payout ratio of 1 is not backed by empirical evidence; JGN proposes 0.68 as the best estimate
- the best estimate of the utilisation rate (theta) is 0.23 because it relies on more recent data and because dividend drop-off studies provide a much better estimate than taxation statistics

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192 Commissioner of Taxation, *Tax Ruling 2009/04, Income tax: effective life of depreciating assets (applicable from 1 July 2009)*, 29 June 2009, p. 93.

193 Section 40.70 applies to assets held before 10 May 2006 and section 40.72 applies to assets held on or after that date.

- combining the payout ratio and theta estimates, the best estimate of gamma is 0.2.

JGN and AER agree on a the definition of gamma

JGN considers that gamma should be estimated as a market wide parameter for the Australian economy and defined (using the Monkhouse definition[194]) as the product of:

- the imputation credit payout ratio—the face value of imputation credits distributed by the firm as a proportion of the face value of imputation credits generated by the firm in the period

- the utilisation rate (theta)—the value of distributed credits to investors as a proportion of their face value.

The AER adopts this same definition in its draft decision.[195]

Payout ratio of one is not backed by empirical evidence

JGN considers that it is inappropriate to adopt the AER's assumed dividend payout ratio of one. Empirical evidence strongly suggests a payout of significantly less than one and therefore JGN considers that 0.68 per cent is the best estimate in the circumstances.[196] The AER provided no new empirical evidence to the contrary in its draft decision.

JGN supports the view of Professor Officer that the Officer framework says nothing about the payout ratio.[197] The Officer CAPM is one of a class of robustly derived tax-adjusted CAPM's where the dividend payout is variable, not something that needs to be assumed.[198] Instead, empirical data provides better estimates of the payout ratio than theoretical assumptions, such as that made by the AER.[199]

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194 P. Monkhouse, 1997, *Adopting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System*, Accounting and Finance, 37, vol. 1, 1997, pp. 69–88.

195 Draft decision, p. 149.

196 As noted recently by ETSA. ETSA Utilities, 14 January 2010, *Revised Regulatory Proposal 2010–2015*, p. 191.

197 R. Officer, 23 June 2009, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*.

198 M. Lally, 2000, *Valuation of companies and projects under differential personal taxation*, Pacific-Basin Financial Journal, vol. 8, pp. 115–133.

For instance, Lally notes on page 117 that: the Officer CAPM assumes that empirical approaches will determine the extent of the utilisation of imputation credits, including the payout ratio variable.

199 Draft decision, p. 150. The AER assumes a 100 per cent payout ratio.

NERA has conducted new empirical analysis—provided in Appendix 6.3—of ATO statistics that clearly shows that the assumption of a 100 per cent payout ratio is inconsistent with the actual behaviour of firms.[200] NERA's analysis finds that on average 68 per cent of imputation credits were paid out between 1996-97 and 2006-07.[201] This result is consistent with the results of Hathaway and Officer[202] and Synergies[203] that JGN relied on in its original AA proposal.

Assuming a payout ratio of one is not only inconsistent with the empirical evidence, but also ignores the practical constraints on the ability of firms to pay out retained credits. In general, a firm will only be able to distribute retained imputation credits in years where it distributes more credits than it creates (that is, in years when the payout ratio is greater than one). This might be possible for some companies with substantial foreign income or a desire to lower equity levels, but it is unlikely to be the case for regulated energy businesses such as JGN. JGN's ability to pay out retained credits in any given year is restricted by both its assumed financing structure (particularly gearing) and the nature of its income streams.

JGN also notes that the pool of retained credits is growing over time,[204] which suggests that firms are struggling to pay out these credits and that investors are not able to access this value. So, even if these credits were eventually paid out, JGN considers that they would not be paid out within five years of being earned, as suggested by the AER.[205]

A better estimate of the utilisation rate (theta) is 0.23

JGN considers that the May 2009 SFG study (**the SFG study**) which estimates theta at 0.23 is the most reliable and current estimate.[206]

The SFG study is more comprehensive than the 2006 Beggs and Skeels study[207] that the AER relies on in its draft decision because it uses a much larger cross-section of businesses and a longer, more recent data period. This view is confirmed by Skeels—a co-author of the 2006 Beggs and Skeels study—who

200 NERA, 5 January 2010, *Payout Ratio of Regulated Firms*.

201 NERA, 5 January 2010, *Payout Ratio of Regulated Firms*, p. 6.

202 N. Hathaway and B. Officer, November 2004, *The Value of Imputation Tax Credits – Update 2004*, Capital Research Pty Ltd, pp. 13 and 24.

203 Synergies Economic Consulting, 28 May 2009, *Gamma: New Analysis Using Tax Statistics*, p. 6.

204 NERA, 5 January 2010, *Payout Ratio of Regulated Firms*, p. 6.

205 Draft decision, p. 150.

206 SFG, *The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)*, referenced in:

C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 3.

207 C. Skeels and Beggs, 2006, *Market Arbitrage of Cash Dividends and Franking Credits*, The Economic Record in 2006, Vol. 82, pp. 239–252.

considers that the SFG study provides the most accurate estimate of the value of theta.[208]

The AER's following criticisms of the SFG study are either overstated or do not apply:

- *Multi-collinearity* – JGN agrees with the AER that dividend drop-off studies are likely to suffer from some multi-collinearity.[209] However this issue will apply not only to the SFG study, but also the Beggs and Skeels study relied on by the AER.[210] The AER is inconsistent in expressing concerns about the SFG study but not applying those same criticisms to the Beggs and Skeels study.

  JGN also considers that the AER's concerns about multi-collinearity in the SFG study are overstated. The standard errors of the estimate do not suggest that multi-collinearity represents any material concern, as analysed in both the Skeels report[211] and the SFG report[212].

- *Filtering and data quality* – JGN considers that the SFG study does properly filter its data set to exclude observations based on shortcomings in the data or where the observations were unreliable on economic grounds. SFG has recently conducted a rigorous sample exercise that shows, after a review of some 236 ASX announcements in relation to 150 observations, there are negligible changes to the results previously reported by SFG.[213] This sample exercise was conducted in response to Dr John Field, an independent statistician, who prepared a statistically robust sampling methodology to be used to interrogate the SFG data set.[214]

- *Economically implausible results* – the AER criticises one set of SFG results where "the coefficient of cash dividends exceeds one dollar are economically

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208 C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 5

C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3.

209 Draft decision, p. 154.

210 Draft decision, p. 158.

211 C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3.1.

212 SFG Consulting, 8 January 2010, *Response to AER Draft Determination in relation to gamma*, paragraphs 19–34.

213 SFG Consulting, 13 January 2010, *Response to AER Draft Determination in relation to gamma.*

214 SFG Consulting, 13 January 2010, *Response to AER Draft Determination in relation to gamma*, p.17.

implausible and therefore cannot be relied upon".[215] JGN notes the AER's concern but reiterates the view of Associate Professor Skeels that:[216]

> [i]f the point estimate is economically implausible but the confidence interval includes economically plausible values, as the preferred SFG results do, then the correct interpretation of the estimates is that they suggest that the true parameter is near to the boundary of economically plausible values. They do not suggest that the true parameter value is an economically implausible value. To attach an implausible interpretation to something when a plausible interpretation is equally probable does not constitute a fair assessment of the statistical evidence.

The above reasons why the AER's criticisms of SFG's report are unfounded are supported by the reports in Appendix 6.3.[217] These reports address concerns about the SFG study that the AER originally raised in the South Australian draft decision and raised again in its draft decision for JGN. Furthermore, Skeels suggests that the concerns raised by the AER are of little practical importance and that the SFG estimate is the most accurate estimate currently available.[218]

Also, JGN reaffirms its view that dividend drop-off studies provide the most reliable and accurate method for estimating theta. JGN considers that these studies better satisfy the requirements of rules 74 and 87 than do tax statistics because they better reflect the true market or economic value of imputation credits.[219] Hence, JGN considers it inappropriate to use tax statistics as part of determining the best estimate of theta that is commensurate with prevailing conditions in the market for funds.

Combining the best payout ratio and theta estimates, the best estimate of gamma is 0.2

JGN proposes a gamma estimate of 0.2. Multiplying the payout ratio estimate of 0.68 and the theta estimate of 0.23, as per the Monkhouse definition, gives a gamma estimate of 0.16, which is consistent with JGN's proposal. Even using an

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215 Draft decision, p.157.

216 C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, p. 28.

217 SFG Consulting, 13 January 2010, *Response to AER Draft Determination in relation to gamma*.

SFG Consulting, 4 January 2010, *Further analysis in response to AER Draft Determination in relation to gamma*.

C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination.*

218 C. Skeels, 28 August 2009, *A Review of the SFG Dividend Drop-Off Study*, p. 5.

C. Skeels, 13 January 2010, *Response to Australian Energy Regulatory Draft Determination*, section 3.

219 This is support by: C Skeels, 12 January, *Response to Australian Energy Regulator Draft Determination*, section 2. On page 10, Associate Professor Skeels states that "the face value of the franking credit overstates its value to the investor relative to that of the corresponding cash dividend".

assumed payout ratio of one implies a gamma estimate of 0.23, which is also consistent with JGN's proposal.

Further, JGN does not agree that an average of theta estimates from tax statistics and dividend drop-off studies—the method used by the AER[220]—is appropriate in the circumstances. As noted above, JGN considers that tax statistics do not represent economic values so should not be used to estimate gamma.

6.4 Amendments to the access arrangement proposal and information

JGN has amended its AAI to apply a post-tax approach to calculating required revenues. JGN has not incorporated any other required amendments. Appendix 10 calculates JGN's tax allowance for the next regulatory period.

[220] Draft decision, pp. 158–160.

7 Incentive mechanism

- For some types of investment, such as discretionary market expansion, the return provided by the WACC may be insufficient for JGN to attract the necessary capital.
- JGN's proposed MEM would provide it with a modest additional return to enable it to justify investment in discretionary expansion projects that are currently marginally uncommercial even though they have potential to provide many new customers in established areas with the benefits of gas supply.
- The MEM has at its core the promotion of the efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas.
- The rules that the AER cites as the basis for rejecting JGN's proposed MEM (84(3) and 98(1)) are not barriers to its acceptance. To the extent the AER considers that 84(3) is a barrier, JGN has revised its proposal to address that concern.

In its August 2009 original AA revision proposal JGN proposed one incentive mechanism for the next AA period—a market expansion mechanism (**MEM**). The MEM gives JGN the incentive to expand the network to unreticulated areas in the Sydney region in addition to business as usual short mains extensions which have been included in the JGN capex forecast.

There are presently some 600,000 homes and businesses within JGN's distribution area that have no reticulated gas supply. The MEM, if approved, would significantly increase the likelihood of gas being made available to a proportion of those homes and businesses over time.

The MEM proposed by JGN is consistent with the national gas objective and the revenue and pricing principles. The MEM has at its core the promotion of the efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas. The MEM provides JGN with a reasonable opportunity to recover at least the efficient costs JGN incurs in providing reference services and provides JGN with an effective incentive to promote economic efficiency with respect to reference services.

7.1 Summary of AER draft decision

The AER draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal to delete section 4.2 titled ‘Expansion incentive mechanism’, which contain JGN’s MEM[221].

Table 7-1 sets out the amendments that the AER required in its draft decision of JGN’s proposed access arrangement in relation to incentive mechanisms.

Table 7-1: Amendments the AER required in its draft decision – incentive mechanisms

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
7.1	Amend the AA to delete section 4.2 titled “Expansion incentive mechanism”	Not incorporated	Sections 7.2.1 and 7.3
7.2	Amend the AAI to: Delete the fourth bullet point in the introduction to chapter 11 (Proposed incentive mechanism) Delete the second paragraph in section 11.1 Delete section 11.4 (Proposed incentive mechanism) Delete and replace the term “Section 11.4” with “N/A” in Table 11-1.	Not incorporated	Sections 7.2.1 and 7.3

7.2 JGN response to AER draft decision

7.2.1 The market expansion mechanism

JGN estimates that there are presently some 600,000 premises—homes and businesses—within its distribution area that do not have access to gas. Many of those premises are in localities that are close to and in some cases surrounded by areas that are already reticulated and many of those localities have been candidates for reticulation for 20 years or more.

If the WACC was adequate compensation for the risks involved then the question must be asked why JGN has not been motivated to reticulate those localities before now? The answer is that for some types of investment, such as discretionary market expansion, the return provided by the WACC is insufficient for JGN to attract the necessary capital.

JGN’s proposed MEM would provide it with a modest additional return to enable it to justify investment in discretionary expansion projects that are currently

221 Draft decision, p. 168.

marginally uncommercial even though they have potential to provide many new customers in established areas with the benefits of gas supply.

7.2.2 Precedents

Other regulators and policy makers have recognised the need to provide network businesses with increased incentives to make discretionary investments and have established innovative regulatory solutions to promote particular objectives.

For example, IPART introduced the D factor for NSW electricity distribution businesses in the 2004-09 regulatory period to encourage demand management activity. IPART described its decision as follows:

> In determining the new regulatory framework for 2004–09, the Tribunal has aimed to ensure that these regulatory barriers [to the use of demand management] are removed, and to neutralise the potential disincentive for demand management created by the change to a weighted average price cap form of regulation (which links revenue to volumes sold). It considers that its final decisions represent a generous treatment of demand management activities. This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions.[222]

and

> The Tribunal has decided that it will introduce a D-factor into the weighted average price cap control formula that allows DNSPs to recover:
>
> - approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs
> - approved tariff-based demand management implementation costs
> - approved revenue foregone as a result of non-tariff-based demand management activities. [223]

IPART, in effect, acknowledges that normal cost recovery arrangements (including WACC) may not provide an adequate incentive or reward for service providers to undertake particular activities that are considered desirable.

It is notable that the AER "[has decided] to apply the D–factor scheme to the NSW DNSPs over the [2010-14] regulatory control period, in the form applied by IPART over the [2005-09] regulatory control period."[224]

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[222] IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Final Report*, June 2004, p. 89.

[223] IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Final Report*, June 2004, p. 90.

There are aspects of JGN's MEM proposal that are similar to the D factor arrangements. For example JGN proposes to quarantine quantities and revenues and costs attributable to MEM developments from the determination of tariffs for reference services for 5 years or until the related capital expenditure is judged to be conforming, whichever is later.

Examples of incentive regimes that operate on a larger scale include:

- incentives for proposed transmission pipelines in the National Gas Law—which take the form of an "access holiday", exempting the pipeline from being a covered pipeline for 15 years[225]

- the telecommunications-specific access provisions in Part XIC of the *Trade Practices Act 1974*, which provide for both anticipatory (in relation to services that are not yet declared services) and ordinary (in relation to services that are declared services) exemptions from the standard access obligations[226].

The incentive mechanism proposed by JGN creates similar incentives to those available to proponents of large gas and telecommunications infrastructure projects – JGN's incentive mechanism has merely been shaped to reflect the smaller scale of investment that would be undertaken in expanding JGN's reticulated gas network into established areas.

The significance of incentives to encourage investment in gas infrastructure have been recognised as being of particular importance in light of the central role that gas is expected to play in a carbon constrained economy.[227]

7.2.3 Response to AER's issues

JGN has not incorporated amendment 7.1 which requires JGN to remove its proposed MEM from the proposed AA, and amendment 7.2 which requires consequential changes to the AAI.

The AER rejects JGN's proposed MEM on the grounds that the AER considers that the MEM does not comply with rules 84(3) and 98(1)[228] and concludes its analysis with the view that:

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224 AER, *New South Wales distribution determination 2009–10 to 2013–14, Final decision*, 28 April 2009, p. xliii.

225 NGL, section 151.

226 NGL, sections 152AS, 152ASA, 152AT and 152ATA.

227 See for example: Second Reading Speech, National Gas Bill 2008, The Hon. P.F. Conlon (Elder—Minister for Transport, Minister for Infrastructure, Minister for Energy), Hansard, SA House of Assembly, 9 April 2008, p. 2884.

228 Draft decision, p. 168.

> the weighted average cost of capital (WACC) provides a return commensurate with prevailing market conditions and the risks involved in providing reference services and so should adequately compensate the service provider for such reticulation projects.[229]

It appears to JGN that, in evaluating the MEM, the AER has sought to find technical reasons why the proposal should be disallowed rather than consider the merits of the proposal and how it might be facilitated.

Compliance with Rule 98(1)

Another one of the grounds on which the AER rejects the MEM is that:

> [the] proposed incentive mechanism is designed to provide a greater incentive for capital expenditure but not to encourage efficiency in the provision of services as is required by r. 98(1) of the NGR.[230]

This proposition is unfounded. The mechanism as proposed is not directed at encouraging capital expenditure but at increasing network utilisation, thereby taking advantage of the economies of scale inherent in the network to improve the efficiency of service provision. The opportunity for increasing network utilisation in this instance involves the expenditure of capital. That cannot invalidate the proposed mechanism under rule 98(1). Rule 98(1) says nothing about the form that an incentive mechanism should take or how the objective of improved efficiency should be delivered. Rule 98(1) is, amongst other things, designed to promote innovation.

The AER acknowledges that "expanding the network into previously unreticulated areas may lead to an overall decrease in costs for all users, but this may only benefit some users".[231] JGN considers that, all else being equal, a decrease in the costs for all users is prima facie evidence of improved efficiency. Assuming they act rationally, consumers in the MEM areas who choose to connect to gas will benefit immediately from that choice through reduced energy costs and access to a wider variety of green options, and consumers generally will benefit through lower tariffs as conforming capital from the MEM areas is rolled into the capital base. Whether the benefit flows through to all users or only some users will depend on how the savings are allocated via tariffs, and is not a relevant consideration.

Incentive regulation is generally described as offering service providers the opportunity to earn above average profits if they respond appropriately to incentives that are established through the regulatory process. The strength of the incentive is determined by the length of time that the service provider gets to retain

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229 Draft decision, p. 167.

230 Draft decision, p. 167.

231 Draft decision, p. 167.

those profits before the benefits are shared with users. For example, incentive carry-over mechanisms (rule 98(2)) extend the length of time that service providers retain benefits thereby amplifying the incentive for them to pursue the desired behaviour. The corollary is that consumers must wait longer to see the benefits of the efficiency gain. The MEM is entirely consistent with these principles.

To the extent that the capital expenditure involved in reticulating the MEM areas is conforming capital expenditure under rules 79(2)(a) or (b) then it will contribute to the recovery of sunk costs and improve the overall efficiency of service delivery.

While the criteria for conforming capital limit the evaluation to "economic value directly accruing to the service provider, gas producers, users and end users" (Rule 79(3)), the MEM will also produce desirable environmental benefits to the extent that consumption of gas in the MEM areas displaces coal-based electricity.

The MEM is entirely consistent with other incentive regimes that are directed at encouraging infrastructure investment that is in the long term interests of end users. The MEM is simply an incentive mechanism that has been appropriately scaled to apply to the expansion of JGN's reticulated gas network into established areas during the AA period.

Alternative mechanisms available under the NGR

The AER mentions a number of provisions that exist in the NGR for recovering the costs of, and managing the return on, sub-economic or marginal projects as possible alternatives to the proposed MEM. These include capital contributions, surcharges, flexible depreciation schedules and the division of customers into tariff classes.

JGN considers that none of these mechanisms are a workable solution to the extent that they would require consumers in a MEM area to pay more than consumers generally through capital contributions or higher tariffs. JGN's requirements for capital contributions are already a barrier to new connections in MEM areas. Certainly none of these mechanisms provide an incentive for JGN to invest in gas infrastructure in areas that JGN has assessed as uncommercial – at least in the start-up phase.

Compliance with Rules 84(1) and 84(3)

As proposed by JGN in the AAI, capital expenditure (including capitalised marketing costs) and additional demand attributable to the MEM would be rolled into the RAB and regulated prices five years after the expenditure. The AER rejects this arrangement as not conforming to rule 84(3). This rule requires that, if at any time changes occur such that previously non-conforming capital expenditure becomes conforming, then the capital expenditure is to be rolled into the capital base as at the commencement of the next access arrangement period.

JGN also recognises that amounts recovered by way of surcharges or capital contributions would be excluded from amounts added to a speculative capital expenditure account (rule (84(1)).

JGN has reviewed the AER's reasons in relation to rule 84(3) and has modified its proposal as described in section 7.2.4 to address the AER's concerns.

7.2.4 Modified proposal for a market expansion mechanism

Nature of JGN's modified MEM proposal

In this revised AA proposal, JGN has modified the MEM in its August 2009 proposal as follows:

- *MEM area expansion* – A 'MEM area expansion' will be defined as an extension which has as its primary purpose, the reticulation of an established residential and/or commercial area. An expansion that is included in JGN's approved capital plan cannot be a MEM area expansion.

- *Not initially part of covered pipeline* – MEM area expansions will be excluded from the application of sub-section 7(a) of the Extensions and Expansions policy. That is, a MEM area expansion will not be taken initially to be part of JGN's covered pipelines.

- *Conforming expenditure assessment after 5 years* – Capital expenditure (including capitalised marketing expenditure) attributable to a MEM area will be held in a market expansion expenditure account. JGN will assess the capital in the account for conformance against the criteria in Rule 79 on a forward-looking basis as at the fifth anniversary of first gas consumption in the MEM area and then annually thereafter. To the extent that the expenditure is found to be conforming, and subject to the AER's approval, it will be rolled into the capital base at the next access arrangement review as from the year in which it is found to be conforming.

- *Financing costs* – Balances in the market expansion expenditure account will be subject to an annual increase at JGN's WACC that the AER has approved.

- *Services and charges* – The services available to delivery points in the MEM areas will be the same as those available in the adjacent established network areas, as will the terms and conditions and charges for those services.

- *Quantities and revenues* – The quantities of gas delivered in a MEM area and the revenue associated with those deliveries will be excluded from the quantity forecast for and revenue derived from reference services until the capital to which those quantities and revenues relate is found to be conforming in accordance with Rule 79.

Benefits to users and customers

Through the revised proposed MEM arrangements, existing customers will be no better or worse off for the first 5 years after an investment is made in a MEM area and after that will be better (and not worse) off to the extent that conforming capital is transferred from the market expansion expenditure account to the RAB and related quantities are included in JGN's quantity forecast for reference services. Customers in the MEM area will benefit from having access to gas at the same network tariffs as customers that JGN services in other areas.

The expenditure required to reticulate the MEM areas is and will continue to be discretionary. JGN cannot commit to that expenditure, or predict the uptake of gas that might be associated with the expenditure, with the degree of certainty required for any such projects to be included in a normal AA proposal. By managing the initial expenditure on MEM projects through the market expansion expenditure account, users are not exposed to the possibility that that expenditure will be included in the total revenue build-up for the next AA period and then not eventuate.

The proposed incentive mechanism will provide JGN with a clear basis on which to evaluate and, as appropriate, proceed to reticulate MEM areas. Without the mechanism and the related expenditure, consumers in the MEM areas will be denied access to gas and, in the longer term, customers will be denied the benefit of lower (network) tariffs.

7.3 Amendments to the access arrangement proposal and information

JGN has not made any of the required amendments. JGN has amended the description of the MEM in a new section 5 of its revised AA revision.

8 Fixed Principles

JGN proposes three fixed principles:

- The first will ensure that JGN is given adequate notice if the AER proposes to revoke its consolidation direction.
- The second will ensure that amounts to be recovered (or returned to users) through tariff variations are carried over between AA periods.
- The third will ensure that the benefits of JGN's market expansion mechanism are realised by extending its operation into subsequent AA periods.

8.1 Summary of JGN original proposal

In its original AA proposal JGN proposed three fixed principles to apply during the next AA period. The proposed fixed principles were:

- *consolidated AA* – that the AER must give JGN a specified period of notice should it intend to revoke its direction to consolidate the AAs for JGN's four covered pipelines
- *cross-period pricing factors* – that any costs JGN incurs under an adjustment factor in the reference tariff policy, but not recovered as prices, fees or charges, in the next AA period will be included as costs in the subsequent AA period
- *expansion incentive mechanism* – that the expansion incentive mechanism that will be established for the next AA period will be retained into the subsequent AA period.

8.2 Summary of AER draft decision

The AER draft decision accepted the first fixed principle proposed by JGN requiring the AER to provide 18 months notice to JGN before revoking the consolidation direction.

The draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal to remove the remaining two fixed principles relating to cross-period pricing factors and the expansion incentive mechanism.

Table 8-1: Amendments the AER required in its draft decision – fixed principles

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
8.1	Amend the AAI to delete clauses 10.2 (cross-period pricing factors) and 10.3 (expansion incentive mechanism)	Not incorporated	Section 8.3

8.3 JGN response to AER draft decision

Amendment 8.1 requires that clauses 10.2 and 10.3 of the AA be deleted. JGN has not incorporated the amendment for the reasons set out below.

8.3.1 Cross-period pricing factors fixed principle – clause 10.2

JGN proposes to retain clause 10.2 of the AA.

JGN continues to hold the view that the tariff variation mechanism should incorporate an annual weather variation adjustment, an annual unaccounted for gas (**UAG**) adjustment, a licence fee adjustment, and other events adjustment for reasons set out in section 13. JGN's review of the AER's draft decision has not persuaded JGN that the incorporation of these adjustments in the tariff variation mechanism is inconsistent with the NGR and JGN has therefore not incorporated amendment 8.1 in its revised proposal.

The price controls of a number of other regulated gas and electricity networks include provisions for pass through pricing factors and incentive mechanism pricing factors that have multi-period effect. These include the Victorian gas and electricity licence fee pass through factors,[232] and the AER's own service target performance incentive scheme.[233]

In the case of the recovery of costs associated with pass through events, which are necessarily time lagged, there is no reason why a regulated firm should be denied cost recovery simply because that time lag coincides with a change in regulatory periods. Imposing such an artificial constraint in instances where a cost has been identified as appropriate for pass through in other years denies the firm an

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232 See for example:

Multinet Gas Access Arrangement Part B Reference Tariffs and Reference Tariff Policy, Part B: Appendix 2, Formula 4, 2 June 2008 and

ESC, Electricity Distr bution Price Review 2006-10 Final Decision Volume 2 Price Determination, October 2005, pp 16 and 23.

233 AER, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009.

opportunity to recover at least its efficient cost of delivering pipeline services as required by the NGL.[234]

8.3.2 Expansion incentive mechanism fixed principle – clause 10.3

JGN proposes to retain clause 10.3 of the AA.

JGN estimates that there are presently some 600,000 premises—homes and businesses—within its distribution area that do not have access to gas. JGN has proposed a market expansion mechanism that, if approved, would significantly increase the likelihood of gas being made available to a proportion of those premises over time. The ultimate effect of the MEM is that it will result in increased network utilisation thereby improving efficiency in the provision of services to all consumers.

The AER requires (by amendments 7.1 and 7.2) that references to the MEM be removed from the AA and AAI. JGN has not incorporated those amendments for the reasons set out in section 7.

If the MEM is to be successful, JGN requires assurance that the MEM will operate beyond the next AA period as provided in clause 10.3.

8.4 Amendments to the access arrangement proposal and information

JGN has retained clauses 10.2 and 10.3 (now clauses 11.2 and 11.3) in the revised AA revision.

234 NGL s. 24.

9 Opex Forecast

- JGN has determined its revised opex forecast of $727.5 million using the widely accepted base year roll forward method. This method is based on JGN's revealed costs and involves the escalation of those costs using scale growth and input cost growth.
- Benchmarking of JGN's costs shows that these costs compare favourably to its peers. This may in part reflect the significant economies of scale and scope that JGN is able to benefit from through its outsourcing of O&M activities to a specialist asset manager, JAM.
- JGN considers that the bottom-up analysis required by the AER should not be the primary means for approving forecast opex, is unnecessarily onerous, and is not consistent with the NGR.
- JGN has incorporated or partially incorporated many of the AER's proposed amendments to its forecast opex. It has not incorporated some elements, such as the exclusion of the outsourcing margin, step changes, cost escalators and capex deemed to be opex.

9.1 Summary of JGN original proposal

For its original AA proposal, JGN employed two methods to forecast its opex costs for the next AA period:

- *base year roll-forward approach* – JGN applied this approach to the majority of its recurrent opex over the next AA period, including:
  - JGN's administration and overheads (**A&O**), which is part of its non-Operating & Maintenance (**O&M**) costs
  - the majority of the fee that JGN will pay to JAM for asset management services under the new asset management agreement (**AMA**).
- *specific year-by-year forecasts* – for some specific cost components, JGN determined specific year-by-year forecasts:
  - government levies
  - marketing
  - unaccounted for gas (including the cost of carbon permits)
  - self insurance

– site remediation

– debt and equity raising costs.

Table 9-1 provides some detail on the approaches that JGN employed to forecast its costs. JGN uses the same cost categories as those allowed by IPART in previous regulatory decisions.

Table 9-1: Opex forecasting methods in JGN's proposal

Sub-categories	% of total opex	Method	Drivers
Operating and maintenance - $456.3m over next AA period (62.7% of total opex)			
IT	11.5%	Base year roll forward scale and cost – single weighted growth rate	Customer numbers, input escalators, saving arising from forecast IT capex initiatives
Engineering	3.4%	Base year roll forward scale (activity volume forecasts) and cost (weighted input cost escalators).	Time writing activities and input escalators
Operational support	8.5%	Base year roll forward scale (activity volume forecasts) and cost (weighted input cost escalators)	Time writing activities and input escalators
Marketing, billing and metering	4.1%	Base year roll forward scale (activity volume forecasts) and cost (weighted input cost escalators)	NIEIR connections growth input escalators
Repairs and maintenance	17.0%	Base year roll forward scale (activity volume forecasts) and cost (weighted input cost escalators)	Service order volumes, time writing activities input escalators
Other direct JAM costs	0.8%	Base year roll forward weighted input cost growth	Input escalators
Indirect JAM overheads	6.1%	Base year roll forward weighted input cost growth	Input escalators

Commercial in confidence

Sub-categories	% of total opex	Method	Drivers
Jemena ESF costs		Base year roll forward weighted input cost growth	Input escalators
Step changes	1.8%	Individually determined item forecasts	New obligations or changes to operating environment
Margin		Asset management agreement	
Admin and overheads - $137.6m over next AA period (18.9% of total opex)			
Direct JGN overheads	14.3%	Base year roll forward	Input escalators
Commercial Group	2.0%	Base year roll forward	Input escalators
Other JGN directs	2.3%	Base year roll forward	Input escalators
Step changes	0.3%	Base year roll forward	Input escalators
Marketing - $33.7m over next AA period (4.6% of total opex)			
Marketing	4.6%	Costing of JGN's marketing strategy	
UAG - $65.2m over next AA period 9% of total opex)			
UAG	9.0%	Product of 2.1% UAG rate, demand and gas price	Total received gas forecast, forecast wholesale gas price obtained from NEMMCO/ACIL Tasman
Government levies - $15.4m over next AA period (2.1% of total opex)			
Mains tax and government revenue levy	2.1%	Trend of recent costs	
Self insurance - $12.1m over next AA period (1.7% of total opex)			
6 individually costed events	1.7%	Expert actuarial assessment	
Deb raising costs - $7m over next AA period (1% of total opex)			
Debt raising costs	1%	Benchmark rate assuming 60% gearing	Forecast RAB

9.2 Summary of AER draft decision

The AER draft decision accepted the forecasting methodology used by JGN but did not accept the opex forecasts because, on the basis of advice from its consultant Wilson Cook, it determined that JGN had provided insufficient information to substantiate its forecasts.

AER accepted JGN's opex forecasting methodology

The draft decision noted that 'in principle, the AER accepts the forecasting methodology used by Jemena.'[235] The draft decision further noted that:

> The AER considers that the advantage of using the base year estimated actual expenditure is that it provides a recent and reliable estimate of actual network expenditure requirements. Coupled with a detailed analysis of activity that will not be required looking forward (one-off costs) in addition to new expected activity (step changes), this should result in a forecast that meets the requirements of r. 91 of the NGR. [236]

AER did not approve JGN's opex forecasts

The AER did not approve JGN's forecast opex of $735.1 million ($2009-10 real) on the grounds that it did not comply with rule 91 of the NGR for the following reasons:

1. a perceived lack of a verified account of actual 2008-09 base year costs, given that JGN's proposal was based in part on estimates for that year[237]

2. a requirement for JGN to provide 'bottom-up' forecast of the activities for O&M expenditure[238] and an associated belief that the AER could not rely on the benchmarking analysis submitted by JGN absent such 'bottom-up' information

3. a view that JGN had not adequately demonstrated that the commercial margin it will pay JAM for O&M 'is efficient or consistent with lowest sustainable cost'.[239]

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[235] Draft decision, p. 181.

[236] Draft decision, p. 190.

[237] Draft decision, p. 179.

[238] Draft decision, p. 189.

[239] Draft decision, p. 185.

AER required extensive adjustments to JGN's opex forecasts

The AER draft decision required that JGN make the following amendments[240]:

- use the actual expenditure incurred in the identified base year, 2008-09 (less identified one-off costs) as a basis for forecasting its opex
- remove the margin applied to expenditure in the O&M category under the outsourcing arrangement between JGN and JAM
- reduce its proposed total step change annual cost
- apply the AER determined real cost escalators in place of those applied by JGN
- remove site remediation costs from the forecast opex
- include expenditure for integrity digs and pigging, and for ad hoc mains and service renewals in the forecast opex (rather than as proposed in the forecast capex)
- reduce its proposed marketing expenditure
- apply the AER determined forecast of UAG cost based on a different level of UAG
- remove carbon costs from the forecast opex
- remove the forecast opex for self-insurance
- estimate the debt raising costs by applying a benchmark rate of 9.2 basis points per year to the AER's approved capex and the resultant capital base in each year of the AA period.

The AER also required JGN to create, maintain and keep a "statement of costs" that contains detailed information on the costs incurred from JAM in the AA period. The AER will use this information to assess JAM's performance at the next AA.

Table 9-2 below summarises the amendments required by the AER.

240 Draft decision, p. 222.

Table 9-2: Amendments the AER required in its draft decision – forecast opex

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
9.1	Amend the AAI to delete table 6-4 titled "opex escalation factors for JGN" and replace it with table 9.11 in the draft decision	Not incorporated	Section 9.3.3
9.2	Amend the AAI and AA proposal to delete the section titled "Carbon scheme" on page 83	Incorporated	
9.3	Amend the AAI to apply the escalation rates given in amendment 9.1 to the opex categories in the proportions provided in table 9.12 in the AER draft decision	Incorporated	Section 9.3
9.4	Amend the AAI to delete table 6-1 titled "JGN forecast opex", 6-6 titled "JGN forecast opex costs excluding O&M over next AA period" and 6-12 titled "JGN forecast O&M costs over next AA period" and replace them with table 9.13 in the AER draft decision	Incorporated	Section 9.3
9.5	Amend the AA proposal to delete section 1.2 *Emissions measurement and permit costs* of schedule 8	Incorporated	Section 9.3.4
9.6	Amend the AAI to delete section 6.6.1 *Site remediation works (Confidential)*	Incorporated	Section 9.3.4
9.7	Amend the AAI to include a new section titled "Statement of costs" containing the text provided in the draft decision	Partially incorporated	Section 1.4.5
9.8	Amend the AA proposal to include a new schedule 10 setting out the information in Appendix D of the AER draft decision titled "Statement of costs template"	Not incorporated	Section 1.4.5

9.3 JGN response to AER draft decision

JGN provides its response to the AER's draft decision in this section as follows:

- *framework and approach* – the framework and approach that should be used for forecasting and assessing opex, based on the rules of the NGR (section 9.3.1)
- *summary of revised forecasts* – JGN's revised opex forecasts (section 9.3.2)
- *base year roll-forward forecast* – a description of JGN's forecast calculations for components that are calculated using the base year roll forward method (section 9.3.3)
- *specific year-by-year forecasts* – a description of JGN's forecast calculations for components that are built up separately (section 9.3.4).

9.3.1 Framework and approach for forecasting and assessing opex

It is good regulatory practice for JGN to develop, and the AER to assess JGN's revised AA revision using, a well-defined framework and approach that is consistent with the requirements of the NGR and NGL. JGN needs to understand that framework and approach for it to provide the AER with the information necessary for the AER to assess in particular JGN's operating expenditure forecasts.

In the absence of a clear framework and approach in the draft decision, this section puts forward one that focuses on the base year roll forward forecasting method used for the majority of JGN's opex, outsourcing and the usefulness of benchmarking.

Methods to determine the efficient base-year cost base

The manner in which JGN determines its base-year cost base forms the foundation of the base year roll forward method, and subsequently how step changes and escalators are applied to form a forecast for the next AA period. When reviewing the draft decision, JGN made significant efforts to understand the AER's reasoning to identify its preferred approach to determining the base-year cost base, its assessment framework, its calculations and, accordingly, its reasonable requirements for information to apply them.[241] While it is clear that the AER sees

[241] Letter from JGN to the AER dated 19 February 2010, *Provision of information from JGN*; letters from JGN to the AER dated 19 February 2010, 1 March 2010 and 8 March 2010, *Clarifications of AER reasons for draft decision*; letter from JGN to the AER dated 3 March 2010, *Notification of identified AER errors in draft decision*; and meetings with AER staff on 24 February 2010 and 4 March 2010.

merit in a base-year roll-forward approach[242], it has also expressed a desire to apply a bottom-up approach to substantiate the base-year cost base.[243]

JGN engaged Mr Geoff Swier of Farrier Swier Consulting to provide an independent expert view[244] of what approaches to forecasting operating expenditure would result in a forecast of operating expenditure:

- 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 delivering pipeline services;
- that will or is likely to contribute to the achievement of the national gas objective;
- that will or is likely to give effect to the revenue and pricing principles; and
- that is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

JGN asked Mr Swier to identify the strengths and weaknesses of each of the approaches identified against these points.

After considering carefully the meaning of the relevant provisions of the NGL and NGR, in particular the concept of 'lowest sustainable cost', Mr Swier evaluated three approaches to determine the base-year cost base with regard to the requirements of the NGL and NGR[245]:

- revealed efficient approach
- a bottom up method, that Mr Swier defines as an independently derived bottom up review of base year costs
- a forecasting approach, as adopted by the AER in the draft decision.

In addition to the benefits the AER itself sees in the base year roll-forward method of forecasting that make it compliant with rule 91, Mr Swier considers that[246]:

> … the other benefits are:

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[242] Draft decision, p. 190.

[243] Draft decision, pp. 190-191.

[244] Appendix 9.1.

[245] Mr Geoff Swier, *JGN Gas Networks (JGN) Access Arrangement 2010: Approach to opex forecasts, Expert opinion*, March 2010, p. 2.

[246] Appendix 9.1, p. 4.

- It is a relatively low cost way of undertaking opex forecasting which I consider contributes to the "reasonable approach requirements" of Rule 74.

- To the extent there is an information asymmetry problem, it reduces the risk of regulatory error which I consider relevant to Section 24 (2) of the NGL.

- The approach is expressly recognised in the Assessment of Compliance, Rule 71 (1) – although I note the AER can infer opex is efficient and complies with other criteria on any approach the AER considers appropriate.

Further:

> This forecasting approach is a relatively low cost way of preparing forecasting because:
>
> - For the service provider:
>
>   – Actual cost information, which should be readily available is used to establish majority of the cost base, with forecasting effort focused on the step changes, the roll forward of base costs, and specific costs components.
>
>   – This forecasting approach is consistent with normal business practices for forecasting opex costs. In general, businesses will prepare forecasts based on roll forward of previous years costs. Initiatives to improve opex efficiency generally are undertaken separately from the forecasting process.
>
> - For the AER:
>
>   – Provided the base year costs are verifiable, then its review efforts can be focused on step changes, the roll forward of base costs, and specific costs.
>
>   – It avoids the costs associated with undertaking an independently derived bottom up review, and dealing with the outcomes of this review (including disputes and appeals).

Mr Swier's view is that the independent derived bottom up analysis approach does not support verification of an opex forecast as having been arrived at on a reasonable basis or as the lowest sustainable cost unless the regulator can overcome certain challenges. These include information asymmetry, engaging advisors with appropriate expertise, scoping of the services and activities, governance to ensure a robust review and to manage regulatory error, and having sufficient time. The adverse impacts on dynamic efficiency would also be a consideration. Further, he states[247]:

> Does the forecasting approach result in a forecast that is prepared on a reasonable basis including the costs associated with preparing the forecast, regulatory review, disputes and appeals?
>
> 106. The costs of this forecasting approach will be significantly higher than Option 1 [the revealed efficient costs approach] including the cost associated with preparing information, engagement of consultants, the regulatory review process, disputes and possible appeals. To the extent the review becomes intrusive, then this may lead to the engagement of multiple consultants.
>
> How well does the forecasting approach address the information asymmetry problem?
>
> 107. To the extent a relevant decision maker considers there is an information asymmetry problem, then this forecasting approach does not address it, and may not be a reasonable basis for arriving at the opex forecast. Conversely, if a decision maker considers information asymmetry is not a material problem, then this forecasting approach may be reasonable basis for arriving at the opex forecast.
>
> What risk of regulatory error does the approach create?
>
> 108. To the extent there is (or is not) an information asymmetry problem, then the forecasting approach increases (or does not increase) the risk of regulatory error. If there is considered to be information asymmetry, then the AER would be determining the entire base year of regulatory costs for a business it knows little about. On the other hand, if there is not considered to be an information asymmetry problem, then this implies that the AER can obtain appropriate advice to understand the business.

In relation to the approach adopted by the AER in the draft decision, Mr Swier's view is that[248]:

> 28. The impact on productive efficiency depends on the extent to which the reduction in opex forecasts to remove the margin earned by JAM does not align with JGN's efficient costs. I am unable to comment on this. However, this forecasting approach gives little confidence that the opex forecast is a reasonable estimate of the lowest sustainable costs.
>
> 29. The impact on economic efficiency is affected by future incentives for dynamic efficiency. The same considerations apply as in paragraph 23.

[247] Mr Geoff Swier, *JGN Gas Networks (JGN) Access Arrangement 2010: Approach to opex forecasts, Expert opinion*, March 2010, p. 20.

[248] Mr Geoff Swier, *JGN Gas Networks (JGN) Access Arrangement 2010: Approach to opex forecasts, Expert opinion*, March 2010, p. 5.

30. From an economic standpoint, the AER's actions in deducting the margin on the basis that inadequate information was supplied, lacks logic and is inconsistent with the normal approaches to forecasting. Therefore, the resulting forecasts may not be arrived at on a reasonable basis, as required by the Rules.

31. There is a risk of regulatory error, because the removal of the margin is only an approximate estimate of the adjustment required, in the AER's view, to ensure that JGN can recover at least its efficient costs. The Rules require that a service provider be given a reasonable opportunity to recover at least its efficient costs

JGN's approach to determining its efficient base-year cost base

JGN endorses and concurs with Mr Swier's conclusion that the revealed efficient cost approach is superior to the other two approaches considered. This was the approach that JGN used as the starting point in its original AA proposal for the cost base for the majority of its operating costs, and is again the basis of its forecast for its revised proposal. For some specific operating cost components[249], JGN has made specific year-by-year forecasts because this was more appropriate for these components.

JGN's approach to determining the base-year cost base, and the scope and level of detail it has provided, is consistent with what the AER and its consultants have accepted in other regulatory proceedings. For example, to the extent that bottom-up analysis has been used and accepted by the AER and Parsons Brinkerhoff (in its report for the AER) to support ETSA Utilities' forecast opex, they did not suggest that the analysis should be as extensive, detailed or intrusive as the approach proposed by the AER and Wilson Cook for JGN.

The AER seemed to imply in its draft decision that it could not use JGN's cost data in its original proposal for the purpose of determining its base-year cost base because it had not been externally verified. The base-year cost base that JGN put forward in its original proposal necessarily comprised some forecast, rather than verified actual costs. It was in a form suitable for the AER to use in its draft decision after the AER incorporated the correction JGN provided in December 2009.

With this revised AA revision, JGN has provided a full year of 2008-09 actual JGN and JAM costs that have been internally and externally verified. This provides JGN with a solid and rules-compliant starting point for the development of its base-year cost base[250]. JGN has also provided additional information for the AER to

[249] The components for which JGN has provided bottom up forecasts are government fees, marketing, UAG, self insurance, site remediation and debt and equity raising costs.

[250] External validation has been provided in confidential appendix 9.2.

understand its base-year cost base and its cost drivers in more detail.[251] In section 9.3.3, JGN affirms the evidence that enables it and the AER to infer that JGN's base-year cost base is efficient.

For JGN to develop and for the AER to review an independently derived bottom up approach, JGN would have to provide the AER with a very large amount of detailed information and the AER and its consultant would need extensive expertise and experience in relation to JGN's business to assess it. The AER would need to take considerable steps to avoid regulatory error, and JGN could not be expected to prepare and provide this information in the time the AER has allowed it to submit is revised AA revision. JGN is a mature business whose opex is highly recurrent. Accordingly, it does not employ a bottom up approach to its own business budgeting and, consequently, this information is not readily available to JGN. If the AER requires JGN to generate a bottom up forecast as a condition of the acceptance of its AA revision, this would take considerable additional time and effort.

In relation to the AER's own approach to determining JGN's base-year cost base, JGN also agrees with Mr Swier that the AER's proposed disallowance of its outsourcing margin on the basis that inadequate information was supplied, lacks logic and is inconsistent with the normal approaches to forecasting. JGN notes that, in its draft decision, the AER did not set out an analysis of its approach to enable it to determine that it would provide a forecast that is compliant with the rules. The following section deals specifically with the treatment of the outsourcing margin.

Framework to assess an outsourcing margin

JGN recognises that the AER wishes to understand more about why JGN holds the view that its outsourcing arrangements are efficient and why they should be considered as part of JGN's base-year cost base. JGN also observes that, in its draft decision, the AER did not set out how it would assess the outsourcing margin as being compliant with the rules relevant to either opex or capex forecasting. It stated only that it required more information.

With its original AA proposal, JGN provided the AER with the AMA and a description of how it was struck and how its efficiency incentives will operate. JGN also provided the AER with several presentations explaining its business, corporate structure and outsourcing arrangements—presentations both before and after JGN lodged its original AA proposal.[252] With this revised AA proposal, JGN puts forward an approach to assist the AER to assess the information JGN has

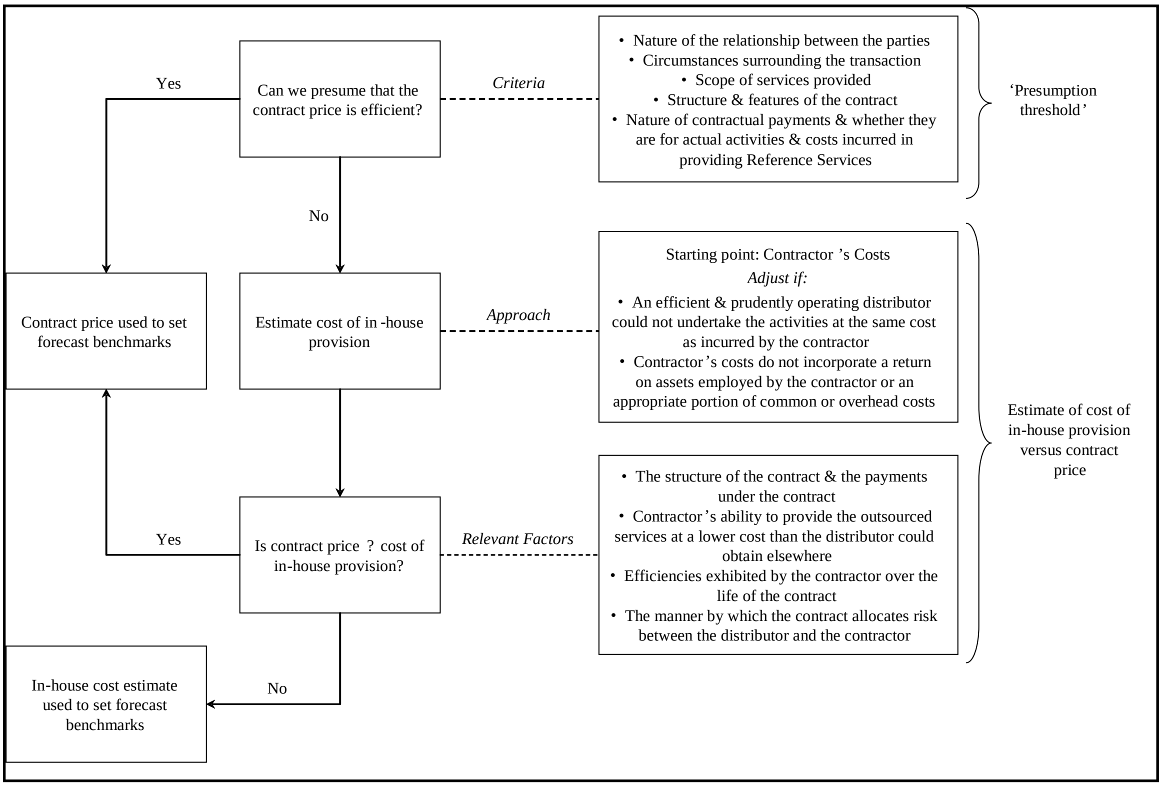
[251] More detail has been provided in Appendices 9.2, 9.5, 9.6 and 9.8.

[252] JGN provided confidential briefings to the AER on 14 August 2008, 28 August 2008, 5 September 2008, 11 May 2009, 26 June 2009 and 4 November 2009.

already provided and some additional information to satisfy the AER's desire to be more fully informed.

The most recent detailed consideration of this issue by a regulator was undertaken by the ESC in the context of the 2008-2012 Gas Access Arrangement Review. Although the ESC's assessment was undertaken by reference to the Gas Code, the framework it has developed is equally relevant under the NGR and the NGL. During this review the ESC developed a two stage inquiry process, which is illustrated in the figure below.

Figure 9-1: Two stage inquiry process



Source: NERA, *Treatment of Outsourcing Arrangements – Multinet Gas Distribution Partnership,* October 2007, p. v.

The first stage of the ESC's inquiry process involved distinguishing between those contracts that could be presumed to be consistent with the operating expenditure and capital expenditure provisions of the Gas Code (i.e. arm's length transactions) and those for which such a presumption could not be made (i.e. related party transactions). Under the ESC's framework, transactions between related parties were deemed not to meet the presumption threshold and so were subject to the second stage of the inquiry process. This stage involves a more detailed examination of the contract and the price struck under it.

The test applied by the ESC in this second stage was designed to establish whether the overall price paid under the outsourcing contract (including any 'margin') was lower than the costs that would be likely to be incurred by a distributor in undertaking those activities itself, i.e. the in-house cost of provision. In circumstances where the contract price was found to be lower than the in-house cost of provision, the ESC concluded that the price would be consistent with the relevant provisions in the Gas Code.[253]

Rather than requiring a detailed ground up estimate of the cost of in-house provision, the ESC's framework used the *actual costs incurred by the contractor as the starting point* for the assessment of the cost of providing the services in-house. In doing so, the ESC noted that it was *not* adopting the position that such costs formed a reasonable final benchmark of prudent and efficient costs for in-house provision. Rather, the ESC explicitly acknowledged that if an outsourcing contract was expected to reduce costs relative to the cost of in-house provision, the full contract price should represent the appropriate cost benchmark under the Gas Code:[254]

> In looking at the actual costs incurred by the contractor in undertaking the contracted activities, the Commission is not adopting the position that only the contractor's actual costs form a reasonable basis for the benchmark of prudent and efficient costs. The Commission accepts that, consistent with the views of both NERA and ACG, if over the relevant time horizon, the contractor incurs lower expected costs relative to providing the services in-house then this is a prudent and efficient outcome. Provided the overall contract payments do not exceed the amount that would have been incurred by the distributor undertaking the activity itself, the full contract amount would represent an efficient level of expenditure.

The costs the ESC considered relevant to add to the contractor's direct costs included:

- a return on and of the assets employed by the contractor;[255]
- an appropriate portion of common costs;[256] and
- an allowance for economies of scale, scope and other efficiencies (such as 'know-how') not otherwise available to the in-house provider.[257]

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[253] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 49.

[254] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Final Decision*, March 2008, p. 43.

[255] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

[256] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

Each of these cost categories are illustrated in the following figure.

Figure 9-2: Contractor's cost categories

ESC's 'economic cost' of in-house provision

Contractor's Direct Costs	Appropriate Portion of Common Costs	Return on Assets Owned by Contractor	Depreciation of Assets Owned by Contractor	Economies of scale & scope and other efficiencies (ie, know-how) unattainable by the provider

One question raised during the ESC's review was that the size of the 'economies of scale, scope and other efficiencies unattainable by the service provider' cost block depend on whether one assumed that the in-house costs were calculated on a stand alone basis or whether they took into account efficiencies arising from other interests in assets held by the service provider (or its parent company).[258] Although the ESC referred to the possibilities of alternative in-house counterfactuals in its Final Decision,[259] it did not reach a definitive view.

Notwithstanding the ESC's silence on this question, explicit guidance has been provided by the Australian Competition Tribunal in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited* (2007) ATPR 42-137. While this decision was made in the context of telecommunications, the principles discussed by the Tribunal in relation to the economies of scale and scope available to the service provider are equally relevant under the NGR and the NGL. In the case before the Tribunal, the ACCC submitted that it was not reasonable for Optus to apply the stand-alone counterfactual when determining costs. The Tribunal disagreed with the ACCC and concluded that Optus' use of the stand alone counterfactual was 'reasonable':[260]

> We consider that determining the costs of a stand-alone mobile operator, for the purpose of determining whether the price terms of the undertaking in relation to Optus' DGTAS are reasonable, is more consistent with the matters set out in s

257 Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 52, footnote 30.

258 NERA, Treatment of Outsourcing Arrangements – Multinet Gas Distribution Partnership, October 2007, p. 41.

259 Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Final Decision*, 7 March 2008, p. 58.

260 *Application by Optus Mobile Pty Limited & Optus Networks Pty Limited* (2007) ATPR 42-137, [122] - [124]

152AH and the objectives in s 152AB than requiring Optus to take into account the cost consequences of it being an operator of a fixed-line network and a mobile network. If the objective of regulating a particular industry is to replicate, as far as possible, the environment of a competitive market, then it is desirable to use as a benchmark criteria or principles which would exist in a competitive market, such as determining the costs of an operator operating in that market.

Determining Optus' DGTAS costs as a stand-alone mobile operator would, all things being equal, be likely to result in the achievement of the objective of promoting competition in markets for listed services: s 152AB(2)(c). That is, in competing with mobile operators who do not operate a fixed line network, Optus may gain a competitive advantage by having access to economies of scale and scope. And Optus will not be at a disadvantage when competing against an integrated operator such as Telstra.

Further, s 152AB(2)(e) requires us to have regard to the extent to which Optus' price is likely to result in the achievement of the objective of encouraging the economically efficient use of, and the economically efficient investment in, the infrastructure by which listed services are supplied. In turn, in determining the achievement of this objective, s 152AB(6)(b) requires us to have regard to the legitimate commercial interests of Optus, including its ability to exploit economies of scale and scope. Determining Opus' DGTAS costs on a stand-alone mobile operator basis promotes these objectives.

Consistent with the Tribunal's decision in this case, any estimate of the in-house cost of provision should be undertaken on a stand-alone basis.

Irrespective of the counterfactual assumed, estimating the in-house cost of provision by reference to the contractor's cost poses a number of practical challenges. The most significant involves quantifying the value of any economies of scale, scope and other synergies available to the contractor but not otherwise available to the service provider. In practice, it may not actually be possible to estimate the value of these efficiencies with any degree of precision.

Given the practical difficulties associated with applying the ESC's test, consideration must be given to what other factors the regulator could satisfy itself of when assessing whether the contract price is likely to be less than the in-house cost of provision and therefore consistent with the operating and capital expenditure criteria specified in rules 79(1)(a) and 91(1).

One alternative that could be employed where the contract price is based on a cost pass through pricing structure would involve undertaking an inquiry to determine whether:

- the contractor's costs (both directly and indirectly incurred costs and an appropriate share of common costs) are *lower* than those that could be achieved by the in-house service provider operating on a stand alone basis; and

- the margin (defined in this context as an amount in excess of the contractor's directly and indirectly incurred costs and an appropriate share of common costs) is *comparable* to that charged by other contractors and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by the contractor.

Providing these two factors are satisfied, it is reasonable to infer that the contract price (i.e. the contractor's costs plus the margin) is lower than the in-house cost of provision and so is *consistent* with the operating and capital expenditure criteria specified in rules 79(1)(a) and 91(a) of the NGR.

The ESC also indicated that it would also be important to consider the non-price terms of any outsourcing arrangement, and the extent to which the contractor has any incentive to pursue productive and dynamic efficiencies over its term, and to pass those efficiencies back through to the service provider (and end-users at the next regulatory reset).[261] Where such provision is made it should provide comfort to the regulator that the contractor's incentives are aligned with the relevant provisions of the NGR, the national gas objective and a number of the revenue and pricing principles.

Finally, it is worth noting that the payment of a margin under an outsourcing contract is consistent with good industry practice[262] and will be designed to enable the contractor to recover a range of legitimate costs including:

- the return on and return of capital required by the contractor to compensate it for the use of the physical and intangible assets employed in the provision of the services; and

- the allowance required by the contractor to self insure against any asymmetric risks arising under the contract.

A margin may also be paid to a contractor to ensure that its interests are aligned with those of the service provider, such as an incentive mechanism that is designed to encourage the contractor to achieve the lowest sustainable cost of service delivery. The payment of an amount in excess of the contractor's incurred costs to encourage the pursuit of efficiencies that would not otherwise occur, is similar in nature to the incentive mechanisms applied by Australian regulators to

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261 Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 54.

262 See NERA, *Benchmarking contractor's profit margins, 28 March 2007 and NERA, Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins Critique*, October 2007.

promote cost reductions by service providers and also constitutes a legitimate cost. The legitimacy of these costs was acknowledged by the ESC in the 2008-2012 Gas Access Arrangement Review: [263]

> The Commission accepts that any third party contractor will require compensation for its endeavours over and above the actual cost of undertaking the contracted activities. A third party contractor would expect to be able to recover all of the economic costs that it incurs to provide the outsourced activity and would expect to benefit from superior performance. Otherwise it would not contract to undertake those activities. Such compensation is not necessarily inconsistent with an efficient level of costs, particularly where the contractor has the ability to provide the service at a lower cost than the distributor could do so itself or obtain elsewhere. Further payments above direct costs may, as NERA suggested, also provide a return to the contractor for:
>
> - the assets *employed by it in the provision of the outsourced services*
> - *efficiencies on the part of the contractor over the life of the contract*
> - *the contrac*tor's common costs.

It follows that any concern the AER may have about the potential for a contract between related parties to result in a transfer of profits should not be addressed by simply excluding the entire margin. Rather, careful consideration of the allowance required by a contractor to compensate it for these legitimate costs is necessary before a decision is made to exclude any part of the margin. Support for this view can be found in the following statement made by the Australian Competition Tribunal (Tribunal) in *Application by United Energy Distribution Pty Ltd* [2009] ACompT 10 (23 December 2009):[264]

> If a distributor outsources activities, the operating expenditure of the distributor will necessarily incorporate a margin it pays to the party providing the outsourced services….It may be that the profit margin payable is not prudent, but that is a separate matter.

Benchmarking is a valid consideration

JGN agrees with the AER and Wilson Cook that benchmarking has its limitations and cannot alone be used to assess whether opex or capex complies with the NGR[265]. However, JGN does not agree with the AER and Wilson Cook that they

263 Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, August 2007, p. 52.

264 *Application by United Energy Distribution Pty Ltd* [2009] ACompT 10 (23 December 2009), para 55.

265 Draft decision, p. 70.

should take no account of benchmarking when assessing JGN's forecast expenditure. Mr Swier[266] and large customer groups[267] support JGN's view.

In the national electricity rules, benchmarking information is one of 10 operating expenditure factors that the regulator must have regard to in deciding whether it is satisfied that the total forecast operating expenditure for the period reasonably reflects the operating expenditure criteria.[268] There is a strong similarity between the electricity and gas rules. This indicates that, while the NGR do not compel the AER or Wilson Cook to take account of benchmarking, they should do so as a matter of good regulatory practice to ensure consistency of the AER's decision making and to adequately inform themselves.

With its original AA proposal and in a subsequent submission, JGN submitted the Economic Insights study with its original AA proposal[269] and a confidential benchmarking study on 10 November 2009, as supporting evidence for its submission in support of its cost forecasts. JGN also submitted expert reports from Parsons Brinkerhoff and KPMG that contain relevant benchmarking information. The studies provided by JGN support the view that JGN's cost efficiency and productivity performance are at least comparable to, and on some measures, better than that of its peers.

In relation to the Economic Insights Report, the AER draft decision notes:

> In regards to the nature of the Economic Insights report, the Wilson Cook report notes that total and partial factor productivity concepts have been applied in Australia for over ten years. The Wilson Cook report notes that it can be accepted that the report provides a supporting opinion that Jemena has obtained value for money for its past operating expenditures and, without evidence to the contrary, is likely to continue to do so.[270]

The AER has not identified any evidence which contradicts Economic Insight's findings or suggests that JGN will not continue to obtain value for money for its opex in the future. However, notwithstanding this lack of evidence, the AER places no weight on Economic Insight's findings or the other benchmarking studies provided by JGN. Instead, the AER elected to accept the view expressed by Wilson Cook that the efficiency of JGN's forecast opex should be assessed using a "bottom-up analysis", stating:

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266 Mr Geoff Swier, *JGN Gas Networks (JGN) Access Arrangement 2010: Approach to opex forecasts, Expert opinion*, March 2010, pp. 23-24.

267 Draft decision, pp. 176-177.

268 National electricity rules, rules 6.5.6(c) and (e).

269 Appendix 6.7.

270 Draft decision, p. 218.

> The Wilson Cook report concludes, that while these studies support claims that Jemena operates with a cost structure within the levels of confidence, benchmarking is best presented as an accompaniment to other substantiating analyses of operating costs. The Wilson Cook report affirms that the lack of a bottom up analysis of operating costs related directly to the cost-efficiency of the services offered and supporting this finding should be noted. The AER agrees with this statement.[271]

For the reasons explained above, JGN does not accept that the required approach to determining its base-year cost base is by using bottom up analysis. Further, there is no precedent for the AER to disregard the benchmarking evidence provided by a service provider altogether in the way that it has done.

On the contrary, the AER and its predecessor, the Australian Competition and Consumer Commission (**ACCC**), have been prepared to accept benchmarking evidence to support their positions in a number of other regulatory proceedings. This section examines the particular cases of ETSA Utilities (**ETSA**), the Roma to Brisbane Pipeline (**RBP**) and Moomba to Sydney Pipeline (**MSP**).

The benchmarking information that JGN has provided in support of its AA proposal is as detailed and thorough as the analysis that the AER has accepted and relied upon in the case of ETSA Utilities.

The AER accepted benchmarking analysis as supporting evidence for its conclusion that ETSA Utilities' base year costs are efficient. The AER "undertook benchmarking analysis, including ratio and regression analysis of measures of ETSA Utilities' 2007–08 opex, and forecast opex, against other Australian DNSPs"[272]. Based on this analysis, the AER's consultant (PB) "concluded that ETSA Utilities' opex forecasts appear relatively efficient from a top–down perspective when compared to the other businesses in the sample."[273]

The AER's overall conclusion in relation to benchmarking was that:

> while benchmarking is a useful high-level analytical tool, [the AER] will currently limit its use to a top–down testing of more detailed bottom–up assessment, informed by due consideration of each of the factors specified in clause 6.5.6(e) of the NER. [274]

On that occasion, the AER did not describe precisely what that "bottom-up assessment" entailed. It is apparent that ETSA Utilities supported its proposal for

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271 Draft decision, p. 218.

272 AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 199.

273 AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 199.

274 AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 200.

some components of its forecast operating costs with further detail—or what the AER[275] and its consultant[276] characterised then as 'bottom-up analysis'. There is no evidence in the documents on the public record[277] that the 'bottom up analysis' undertaken by ETSA Utilities and PB are anything like the analysis Wilson Cook[278] contemplated for JGN in terms of scope and detail. Rather, this 'bottom up analysis' appears to be essentially the same as the analyses that JGN has provided in support of its forecasts as described in the operating and maintenance volume and activity drivers report included at Appendix 9.8 and summarised in Table 9-1.

The ACCC's December 2006 final decision in relation to RBP's access arrangement discussed benchmarking in some detail. In short, the final decision indicates that:

- the ACCC agreed with APT Petroleum Pipelines Ltd (**APTPPL**) that benchmarking has limitations[279]

- the ACCC noted that section 8.37 of the Gas Code (the provision against which non-capital costs were to be assessed at the time):

  > does not suggest, however, a top down approach to the assessment of non-capital costs. <u>Benchmarking may provide broad evidence</u> but it does not supplant the assessment of specific costs by the regulator. Given the limitations of benchmarking … the fact that a pipeline may appear to perform relatively well in the benchmarking exercise does not mean that all the costs included in its total non-capital costs would be consistent with the code requirements.[280] (emphasis added)

- The ACCC summarises its position as follows:

  > The ACCC, while recognising the limitations of benchmarking studies, reiterates its position stated in the draft decision – that the KPIs provided by

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275 AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 193.

276 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, undated, pp, 128, 136, and 139.

277 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009

The PB report commissioned by the AER: PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, undated, and

The AER's draft determination: AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009.

278 Wilson Cook report, footnote 53, p. 28.

279 ACCC, *Final Decision, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, 20 December 2006, p. 233.

280 ACCC, *Final Decision, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, 20 December 2006, pp. 136-137.

> APTPPL broadly support, and are consistent with, the conclusion that the proposed non-capital costs (as amended) are reasonable and comparable with those of a prudent service provider operating efficiently in accordance with the code. However these broad indicators should not be given an elevated evidentiary value. [281] (emphasis added)

The ACCC conducted its initial review of the MSP access arrangement over a number of years and issued its Final Decision in October 2003. The ACCC took the following position in relation to benchmarking:

> As argued in the Draft Decision, the Commission is aware of the limitations of benchmarking and KPI comparisons. As suggested by EAPL, limitations include the impact of different pipeline characteristics on outcomes, such as size and terrain. Other limitations include the uncertainties of adjustments (such as fuel costs) and the fact that some performance indicators do not capture all relevant information (such as the fact that operating costs depend on the extent of capital expenditure and vintage of the assets). Despite these limitations, the Commission considers that KPIs provide an important mechanism to corroborate the legitimacy of costs proposed by service providers.[282] (emphasis added)
>
> The Commission reiterates that it is aware of the limitations of benchmarking studies, and concurs with EAPL that the traditional difficulty of 'normalising' pipelines remains. … However, the Commission considers that the KPIs noted above in relation to operating costs per 1 000 km, non capital costs per km and non capital costs per km per PJ provide broad evidence in support of the Commission's concerns with EAPL's proposed operating and maintenance cost requirements.[283] (emphasis added)

In particular, and despite the acknowledged limitations of benchmarking studies, the ACCC relied on benchmarking results to substantiate its final decision on non-capital costs, stating:

> Non capital costs on the MSP are higher than those on more comparable pipelines, namely the DBNGP, the GasNet System and the MAPS (which, due to data limitations, includes compressor maintenance costs). Accordingly, this benchmark provides some secondary support to the view that EAPL's costs may exceed those that would be incurred by an efficient and prudent service provider.[284] (emphasis added)

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281 ACCC, *Final Decision, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, 20 December 2006, p. 233.

282 ACCC, *Final Decision, East Australian Pipeline Limited Access arrangement for the Moomba to Sydney Pipeline System*, 2 October 2003, p. 310.

283 ACCC, *Final Decision, East Australian Pipeline Limited Access arrangement for the Moomba to Sydney Pipeline System*, 2 October 2003, p. 317.

284 ACCC, *Final Decision, East Australian Pipeline Limited Access arrangement for the Moomba to Sydney Pipeline System*, 2 October 2003, p. 156.

Conclusion

It is good regulatory practice for JGN to develop and the AER to assess JGN's revised AA revision using a well-defined framework and approach that is consistent with the requirements of the NGL and NGR. In the absence of such in the draft decision, JGN has put forward they approach it believes will provide forecasts that comply with the NGL and NGR.

This approach includes the use of the base year roll forward method with revealed cost as the starting point for the base-year cost base. It also involves the consideration of benchmarking as having the potential to provide a high level secondary support for the outcome.

9.3.2 Summary of JGN's revised opex forecasts

JGN has had regard to the AER's required amendments and revised its opex forecasts for the purposes of its revised AA proposal.

JGN's has revised opex forecast for the next AA period is summarised in Table 9-3.

Table 9-3: JGN forecast opex for revised AA revision

			Next AA period				
	2008-09 (adjusted base year)	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Non-O&M	47.24	51.27	52.86	53.48	53.99	54.88	55.70
O&M	83.42	82.15	85.30	87.42	91.54	94.08	97.94
Total forecast opex	**130.66**	**133.42**	**138.17**	**140.89**	**145.53**	**148.96**	**153.64**

The forecast opex shown above is based on JGN's responses to the amendments required by the AER summarised in Table 9-4 below.

Table 9-4: JGN's responses to the AER's draft decision – forecast opex

Change	Related AER amendments	JGN incorporation	Summary of explanation	Explanation in this document
Base year costs	9.4	Not incorporated	Based on actual externally verified 2008-09 costs	Section 9.2

Change	Related AER amendments	JGN incorporation	Summary of explanation	Explanation in this document
Outsourcing margin	9.4	Not incorporated	Outsourcing margin	Section 9.3 Appendix 9.4A
Step change costs	9.4	Not incorporated		Section 9.3.3 Appendix 9.5
Cost escalators	9.1, 9.3, 9.4, 9.5	Not incorporated	Have used updated cost escalators that reflect current economic conditions and more robust forecasting methods than AER	Section 9.3.3 Appendices 3b.5, 3b.6, 3b.7.
Demand forecasts	9.4	Not incorporated	JGN has updated base year costs according to new NEIER demand forecasts	Section 9.3.3 Appendix 11.1
Site remediation costs	9.4	Incorporated	JGN has removed site remediation costs from forecast opex	Section 9.3.4
Capex deemed to be opex	9.4	Not incorporated	Consistent with its capitalisation policy which E&Y have reviewed, JGN has included these costs in capex	Section 9.3.4 Appendix 3b.4
Marketing expenditure	9.4	Partially incorporated	JGN has removed the previously proposed $8.2 million increase. Based new costs on 2008-09 actuals with one-off adjustment	Section 9.3.4
UAG	9.4	Incorporated	JGN has applied anew UAG target and adjusted for demand forecasts	Section 9.3.4

Change	Related AER amendments	JGN incorporation	Summary of explanation	Explanation in this document
Carbon costs	9.2, 9.4, 9.5	Not incorporated	JGN has removed direct costs because passed through. JGN has not removed secondary effects	Section 9.3.4
Self insurance	9.4	Not incorporated		Section 9.3.4
Debt raising costs	9.4	Partially incorporated	JGN has used the AER debt raising benchmark. JGN has included equity raising costs that will apply under new inputs	Section 9.3.4

JGN constructed O&M forecast from individual forecasts for 9 subcategories of expenditure.

JGN has relied on detailed work activity modelling for the JAM direct cost elements of non-IT O&M. JGN has previously presented this modelling to the AER and Wilson Cook,[285] and it has provided a detailed report (at appendix 9.8) explaining the activities and drivers underlying these forecasts in order to better allay the AER's residual information concerns. This report shows that JAM's volume and activity forecasting model is built up from over 56 individually forecast activities.

9.3.3 Base year roll forward forecast

JGN has forecast its opex using the base year roll forward approach using the revealed cost approach to determine its efficient cost base. While JGN applied the same approach for its original AA proposal, the following description of how JGN has applied it contains different terminology to align it with Mr Swier's report and to aid the AER's understanding.

JGN started by revealing its actual 2008-09 costs for:

- JGN's administration and overheads
- the fee that JGN paid to JAM for asset management services.

[285] Workshop on 16 October 2009. Meeting between AER Staff, Wilson Cook and JGN, 16 October 2009.

JGN then adjusted these costs to create its (revealed) efficient base-year cost base. JGN adjusted its actual costs to:

- transfer some costs to different categories
- remove one-off and non-recurrent costs that occurred during 2008-09
- make positive and negative step changes
- replace the 2008-09 outsourcing margin with the margin JGN will pay under its AMA.

JGN then rolled these costs forward to determine the opex forecast for each year into the next regulatory period by applying:

- scale growth for JGN's revised demand forecasts to JAM's direct costs
- JGN's revised labour and material cost escalators
- JGN's revised inflation forecast, which adopts the AER's method.

The following sections describe each step in more detail and explain why JGN and the AER can infer that JGN's base-year cost base is efficient.

JGN's actual 2008-09 costs have been validated by external consultants

JGN has obtained an independent expert forensic accounting opinion from Cassandra Michie of PricewaterhouseCoopers (PwC), provided in Appendix 9.2, which validates that:

- the costs have been sourced from the accounting systems of the relevant entities as outlined in Table 9-5
- the WOBCA allocation has been applied using the same methodology that PwC previously reviewed and is consistently applied across all Jemena assets and other JAM clients
- transaction testing confirms there are no 'concealed profits' between entities.

JGN has updated its base-year cost base for 2008-09 actual data

JGN has now updated its opex cost stack for full year 2008-09 actual data. At the time of JGN's original proposal, actual cost data was not available for the full 2008-09 year. As a result, JGN estimated its actual 2008-09 costs using some actual costs and some estimated data.

Table 9-5 shows JGN's revealed actual cost along with the adjustments necessary for it to determine its efficient cost base.

Table 9-5: JGN actual 2008-09 costs with adjustments to create efficient cost base (2009 $million)

Cost category	Source	PwC Report	One-off costs	Capitalisation	Revealed costs	Transfer costs	Step changes	AMA margin	Efficient cost base
O&M									
JAM direct	PWC – JAM directs	45.52	-1.63	-4.03	39.86	19.79	-1.64		58.01
JAM indirect	PwC – WOBCA non-ESF	16.32		-1.38	14.94	-6.34			8.60
JAM share of ESFs	PwC – WOBCA secondary	31.80	-3.09	-4.93	23.77	-17.32			6.45
AMA margin	Calculated								
A&O									
JGN share of ESFs	PwC – WOBCA primary	20.19	-2.50		17.69	0.85			18.54
JGN other direct	PwC – JGN directs	2.61			2.61	3.01			5.62
Marketing									
JGN direct	JGN general ledger	6.04			6.04		0.51		6.55
UAG									
JGN direct	PwC – JGN directs	12.66			12.66				12.66
Govt levies									
JGN direct	PwC – JGN directs	2.99			2.99				2.99
Total		**138.13**	**-7.22**	**-10.34**		**-0.00**	**-1.13**		

Nature of each specific adjustments

The JGN forecast data model (appendix 9.8) contains the detail of each type of adjustment shown in Table 9-5.

Appendix 9.5 contains considerable substantiation for JGN's proposed step changes.

JGN encourages the AAER to examine its substantiation and models in detail. For the draft decision, the AER explicitly excluded examination of JGN's models which contained extensive detail and reconciliation to JGN's forecast. Wilson Cook then took the view that JGN had not provided such information.[286]

Comparison with previous submissions

Table 9-6 shows JGN's efficient cost base and compares this to its cost base in the original AA proposal and its cost base as corrected in December 2009.

Table 9-6: JGN current efficient cost base in comparison to earlier submissions (2009 $ millions)

Cost category	Efficient cost base excluding step changes (A)	Estimated cost base in original AA proposal (B)	Corrected estimated cost base submitted on 18 Dec 09 (C)	Difference between current and estimated cost base (A – C)
O&M				
JAM direct	59.65	65.54	67.23	-7.58
JAM indirect	8.60	4.10	2.50	6.10
JAM share of ESFs	6.45	0.69	4.64	1.81
Outsourcing margin				
A&O				
JGN share of ESFs	18.54	15.14	16.24	2.30
JGN other direct	5.62	5.89	5.89	-0.26
Marketing				
JGN direct	6.04	6.30	6.30	-0.26
UAG				
JGN direct	12.66	12.24	12.24	0.42

Commercial in confidence

286 Wilson Cook report, p. 4 and footnote 50, p. 24.

Cost category	Efficient cost base excluding step changes (A)	Estimated cost base in original AA proposal (B)	Corrected estimated cost base submitted on 18 Dec 09 (C)	Difference between current and estimated cost base (A – C)
Govt levies				
JGN direct	2.99	3.05	3.05	-0.06
Total				

Note: JGN's original proposal contained an error in calculating the adjusted base year data.[287] JGN corrected the error on 18 December 2008 and demonstrated that the correction was in line with its description of costs in its original proposal. The AER declined to accept the correction for the purposes of its draft decision.

Outsourcing margin

JGN's application of the framework to assess outsourcing is contained in Appendix 9.4B.

Cost escalation

For its original AA proposal, JGN relied on an earlier report prepared by Competition Economists Group (CEG), using futures data and expert labour cost forecasts from Macromonitor, BIS Shrapnel and Econtech, for set cost escalators in its original proposal. For its revised AA proposal, JGN has applied cost escalators that Competition Economists Group (CEG) updated to take account of the most recent economic data.[288] JGN's cost escalators, for labour, steel, aluminium, polyethylene, concrete and the CRPS, are shown in Table 9-7 below. JGN has applied these updated escalators using the weightings set out in amendment 9.3 of the AER draft decision.

Table 9-7: JGN opex cost escalators

Escalator	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
EBA labour	1.9%	0.0%	1.4%	1.6%	2.2%	2.2%
Non EBA labour	1.3%	1.2%	1.9%	3.4%	4.0%	3.3%
Aluminium	-0.6%	34.7%	3.4%	1.0%	0.4%	0.6%
Steel	-17.9%	41.9%	7.8%	-0.7%	-1.9%	-1.6%
Polyethylene	-4.5%	28.6%	-0.2%	-2.1%	-2.6%	-2.2%

287 Letter from JGN to the AER dated 3 March 2010, *References in the draft decision to errors in JGN's proposed access arrangement revisions.*

288 Appendices 3b.5 and 3b.6.

Commercial in confidence

Escalator	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Concrete	-1.6%	-0.9%	2.9%	3.6%	2.1%	0.9%

Section 3b.3.9 describes JGN's cost escalators in more detail.

In its draft decision, the AER agreed that the CEG methodology was superior to that of Access Economics. However, the AER's draft decision did not to approve JGN's original cost escalators on the grounds that there had been significant changes in the economic outlook and fluctuations in economic data since the CEG report was published. The draft decision stated:

> For the reasons outlined in chapter 3, the AER is not satisfied that the proposed cost escalators comply with the requirements of r. 91 of the NGR and r. 74(2) of the NGR. As a result the AER requires Jemena to amend its forecast operating expenditure by applying the real cost escalators set out in amendment 9.1. The AER considers that, these escalators should be updated in the final decision to allow for consideration of changes in economic circumstances and updated data and meet the relevant rule requirements[289].

CEG's updated report now represents both the superior methodology and more up to date results. Accordingly, it is JGN's best estimate on a reasonable basis.

Demand forecast

As set out in chapter 11, JGN has obtained an updated expert demand forecast from NIEIR. JGN has used this revised demand forecasts to update its forecast UAG costs.

Inflation forecast

JGN uses forecast inflation of 3 per cent to convert 2009 dollar values to 2010 dollars, relying on the RBA's most recent monetary policy statement.[290]

Why JGN and AER can infer that JGN's base-year cost base is efficient

NGR rule 71(1) enables the AER to infer efficiency from the operation of an incentive mechanism. JGN engaged Mr Swier to provide an expert opinion on what facts, materials or evidence would enable the regulator to infer that forecast opex expenditure is efficient.

Mr Swier's opinion is set out in section 4 of Appendix 9.1. Table 9-8 summarises the considerations relevant to a revealed efficient cost method. It also explains the JGN's factors, material and evidence.

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[289] Draft decision, p. 203.

[290] RBA, *Monetary Policy Statement*, 4 February 2010.

As Table 9-8 shows, JGN and its asset manager have faced significant incentives in the past which provide assurance that its revealed costs will be efficient. The effectiveness of these incentives is evidenced by the comprehensive benchmarking analysis that JGN has previously provided to the AER.

Table 9-8: Considerations for efficient revealed cost method

Test	Relevant considerations	JGN's factors, material and evidence
Past incentives and performance	Past trends since the network became subject to economic regulation under the Gas Code and prior to the earlier AA period(s) including: • incentives established in prior AAs • evidence on opex productivity outcomes.	• JGN has been subject to independent economic regulation since 1996. • For previous AA periods (1996-2001 and 2000-05), the IPART regulatory framework included a fixed opex allowance, which provided an incentive for JGN to become more efficient over the period and capture the gains. Implicit in the 2000-05 allowance was a 3% efficiency target. • IPART determined a price cap giving JGN an incentive to grow output while being constrained to the approved opex forecast, thereby improving productivity. • The Economic Insights TFP study[291] shows JGN's opex PFP benchmarks compare favourably in earlier periods.
	Trends and outcomes for opex productivity changes in the current AA period, including: • how the regulator established the opex forecast and the price control and incentives these created • other productivity factors incorporated by the regulator	• For the current AA period, IPART also determined a fixed opex allowance and a price cap, and similar incentives operated. For the current, IPART set a 1.5% efficiency target. • This target was lower than the previous AA period in recognition of JGN's maturity as a business and its proximity to the efficiency frontier. • JGN experienced significantly lower demand than forecast, its revenue was constrained. Therefore, it had an even stronger incentive to reduce costs.
	Out turn of actual opex against the opex forecast provided by the regulator.	• JGN's expected opex for the current AA period is 5.6% less than IPART allowance

291 Economic Insights, *The Productivity Performance of Jemena Gas Networks' NSW Gas Distribution System*, 18 August 2009, figure 3 (Appendix 6.7 of JGN's original AAI, 25 August 2009), p. 28.

Test	Relevant considerations	JGN's factors, material and evidence
	TFP studies on relative productivity improvement compared to peers.	• The Economic Insights TFP study[292] shows JGN's opex PFP benchmarks compare favourably the current AA period.
Current performance	Current conduct showing network is acting efficiently and in accordance with accepted good industry practice including: • material on relevant strategies, policies and procedures (e.g., maintenance policies and procedures) • evidence from benchmarking studies.	• JGN has negotiated an AMA with extensive incentive provisions and risk allocations to achieve lowest sustainable cost and service quality.[293] • JGN benefits from the JAM procurement policy[294] which provides for sound competitive tendering. • A JAM benchmarking report[295] submitted to the AER demonstrates that JGN's operating costs compare favourably on a number of metrics.
	Productive efficiency of current outsourcing arrangements including, economies of scope and scale, and incentive structures.	• JAM is largest energy network asset manager in Australia and can therefore achieve economies of scale and scope. • JGN can benefit from these economies through its AMA governance and pricing structure.
Review of opex forecasts	Review base year costs to reference back to actual costs	• JGN has provided an independent expert report that externally validates its cost information to actual costs.[296]
	Review (not a detailed investigation) the reasonableness of forecast step changes, escalation factors and specific costs	• JGN's escalation and demand forecasts are supported by independent expert reports from CEG and NIEIR, respectively. • JGN has used detailed activity modelling to escalate for volume scale. • For some cost components, JGN has determined specific year-by-year forecast with regards for detailed activity planning and expert evidence.

292 ibid.

293 Appendix 9.4A contains a detailed description of the AMA incentive structures.

294 Appendix 3b.11.

295 JAM, *Jemena Gas Networks Access Arrangement Information: Benchmarking of Operating Expenses*, 11 September 2009 (contained JGN submission to AER on 10 November 2009) (confidential).

296 Appendix 9.2.

9.3.4 Specific year-by-year forecasts

In this section JGN describes its opex forecasts for elements that it forecasts on a year-by-year basis. JGN does not apply the standard base year roll forward approach to these costs because either:

- base year costs are not necessarily representative of the future
- an alternative method is likely to derive a better estimate in the circumstances.

As for its original AA proposal, JGN has forecast some specific cost components on a separate year-by-year basis. These are costs where either (a) base year costs are not necessarily representative of the future, or (b) a different basis will provide a better estimate in the circumstances. These costs include:

- government levies
- marketing
- unaccounted for gas (now excluding the cost of carbon permits)
- self insurance
- site remediation
- debt and equity raising costs.

This section also deal with costs that the AER believes are not capital in nature and should be treated as opex: mine subsidence, ad hoc mains and service renewals, pigging and integrity digs.

Marketing

JGN has partially incorporated the AER's draft decision:

- As required by AER amendment 9.4, JGN has remove its proposed $8.2 million increase in marketing expenditure
- JGN has not substituted the AER's marketing cost of $6.5 million. Rather, JGN has revised its forecast marketing expenditure on the basis of its actual expenditure in 2008-09, adjusted by $0.51 million to correct for the abnormally small number of incentive claims made in 2008-09.

Table 9-9 shows JGN's proposed base year marketing expenditure.

Table 9-9: Proposed base year marketing costs ($ nominal million)

	2008-09 Actual	2008-09 Adjustment	Base Year Costs
Advertising and marketing	5.07		5.07
Incentive payments	0.97	0.51	1.48
Total	6.04	0.51	6.55

In the rest of this section JGN explains its marketing cost forecasts in more detail.

In its original proposal, JGN estimated its 2008-09 base year marketing costs to be $6.46 million. JGN then proposed to increase its annual marketing expenditure to $8.2 million for the years 2011-15, and included in the demand forecast an additional growth of 150 TJ per annum on top of the NIEIR forecast linked to this marketing spend.

The AER draft decision did not accept this increase in marketing expenditure. Its draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to remove this expenditure and substitute an amount of $6.5 million per annum based on JGN's estimated base year costs.

JGN has incorporated the AER's decision not to allow the $8.2 million increase, but has not incorporated its amount of $6.5 million, instead using actual expenditure for 2008-09 which is now available. Table 9-10 shows that JGN's actual market expenditure in the 2008-09 base year was $6.04 million, $0.42 million below the amount estimated in its original proposal.

Table 9-10: Marketing costs ($ nominal million)

	2008-09 Estimate	2008-09 Actual	Variance
Advertising and marketing	5.64	5.07	-0.57
Incentive payments	0.82	0.97	0.15
Total	**6.46**	**6.04**	**-0.42**

Actual 2008-09 marketing costs include two significant one off events which materially impacted the costs for that year. JGN has therefore made a one-off adjustment to its base year marketing costs to ensure that it provides a representative level of expenditure that is consistent with previous years' expenditure and current performance for the 2009-10 year to date.

Commercial in confidence

Coinciding with this event, in February 2009, the Federal Government announced changes to its hot water rebate scheme. These changes removed the requirement for means testing of rebate recipients and increased the rebate for the replacement of electric storage hot water systems with electric heat pumps to $1600. This increased rebate, combined with the NSW rebate of $1000 and REC payments, reduced the cost to consumers of replacing storage electric hot water systems to less than $500 and in many advertised circumstances replacement systems were offered at no cost to consumers. As a result the number of electric to gas conversions dropped dramatically as did the level of incentive claims.

In September 2009 the Federal and NSW Governments announced reductions in the rebates on heat pump systems to $1000 and $700 respectively. This had an immediate impact on the market, with gas regaining its competitive position against heat pumps. These changes were supported by a change in JGN's marketing approach to direct its incentive payments to major appliance manufacturers and installers and resulted in gas hot water system sales and incentive claims returning to the levels previously expected.

Unaccounted for gas forecast

JGN has updated its unaccounted for gas (**UAG**) forecast to incorporate:

- the UAG target rate of 2.34 per cent set out in the AER's draft decision[297]
- the updated NIEIR demand forecasts set out in chapter 11.

JGN has partially incorporated the AER's draft decision in relation to carbon permits.

JGN has incorporated AER amendments 9.4 and 9.5 to the extent that they require JGN to remove the forecast costs associated with JGN's anticipated obligation to purchase carbon permits for deemed fugitive gas emissions (instead treating that expenditure as a cost pass through). Chapter 13 discusses this in more detail.

Unlike carbon permits, JGN does not consider that a pass through mechanism necessarily offers reasonable opportunity to recover input price changes associated with the CPRS. This is because it will be difficult to isolate and attribute increased costs to the operation of the CPRS outside other price effects, quantify the cost effects into a single event which satisfies the materiality threshold, and identify an appropriate trigger to allow cost pass through claims. Chapter 3b discusses this in more detail.

Self insurance

JGN has not incorporated the AER's draft decision in relation to self insurance.

The AER draft decision stated that:

> Self insurance is appropriate for the coverage of risks that may not be externally insured and are not otherwise provided for in another total revenue building block.
>
> Jemena proposes self insurance for certain business risks. The AER's analysis and consideration of Jemena's self insurance allowance is provided in confidential Appendix C. The AER has assessed the proposal in accordance with r. 91 of the NGR and considers that Jemena has not adequately specified the relevance of the risks to its business or provided for a self insurance premium arrived at on a

[297] Draft decision, p. 210.

> reasonable basis and does not represent the best forecast or estimate possible. The AER notes that in the circumstances of an adverse event occurring Jemena can vary its access arrangement or in some cases seek a cost pass through in order to recover the cost of the adverse event.[298]

JGN considers the AER's analysis reflects a misunderstanding of the rigour behind JGN's expertly determined self insurance forecast and the businesses commitment to this level of risk incidence.

To support the prudent ongoing management of its network, JGN undertook a major review of its insurances, self insurance and potential pass through requirements during 2008 and 2009. This culminated in a decision by JGN's board to self insure for certain items based on the expert actuarial assessment of these risks.

JGN commissioned Marsh Risk Consulting (**MRC**) to prepare an expert quantification of these self insurance costs that could potentially affect JGN. MRC's expert report was provided in Appendix 6.5 of JGN's original AAI proposal.

From the events costed in that expert report, JGN management reviewed the risk consequences and corresponding regulated recovery arrangements such as pass throughs or cost forecasting in order to determine a prudent sub-set of events for which JGN should self insure. These events totalled an annual self insurance premium of $2.45 million in $2010 dollars.

JGN does not accept the AER's view that its self insurance events for key asset damage and public liability were 'not clearly defined'.[299] JGN notes that these events have been sufficiently defined to enable expert quantification by MRC. Moreover, Ms Jacqueline Reid of MRC has stated in her expert witness statement that:

> I have read the Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia and have made all the inquires that I believe are desirable[300]

In this context JGN considers that the events have necessarily been both clearly and adequately defined as a qualified expert of this calibre would not be able to quantify these events or testify in this manner absent such definition.

JGN also disagrees with the AER's conclusion[301] that regulatory cost pass throughs are a viable alternative to JGN's proposed self insurance in all identified instances because:

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298 Draft decision, pp. 212–13.

299 Draft decision, pp. 364, 367.

300 JGN access arrangement information, 25 August 2009, Appendix 6.5, p. 57.

301 Draft decision, p. 365.

- the self insurance values, and several of the total event values fall under the AER's proposed pass through threshold of 1 per cent of JGN's annual revenues of around $4.5 million

- the AER's required amendment 13.11 requires that pass through costs are 'building block components of total revenue'[302] yet the AER states with respect to self insurance that 'The AER does not consider that lost revenue is a building block component of total revenue'[303].

Finally, regarding environmental contamination events, the AER states:

> the AER also notes that the operating expenditure for self insurance for the known sites may be double counted as the incurred costs for known sites is already provided for in the proposed operating expenditure forecasts. Both amounts of operating expenditure are covering the same costs to be incurred in the access arrangement period.

and

> Jemena employs JAM and contractors to undertake capital works. The AER assumes that a prudent service provider would seek through contractual means to indemnify itself against risks that relate to the activities of its contractors particularly if they relate to current activities of that contractor. The AER notes that such a clause is contained in the Asset Management Agreement (AMA). This is reinforced by the Marsh report which concludes that negligence by JAM employees or contractors has an estimated operating expenditure for self insurance of $0. The AER considers that failure to meet environmental obligations is not a relevant business risk that should be borne by Jemena under the current AMA.

With respect to JGN's original proposal for site remediation costs, JGN notes that there was no double counting between this event and the forecast for known sites in the proposed opex allowance. JGN further notes that the AER draft decision rejected these forecasts costs. JGN has incorporated this aspect of the AER draft decision in its revised proposal.

Regarding the allocation of risk and liability under the AMA, JGN agrees that it is prudent to seek a level of indemnity through efficient outsourcing contracts with well defined allocation of risks to the parties who can best manage these risks.

JGN agrees that this is achieved for some of the environmental contamination events MRC identified (i.e. the part MRC determined to be zero) and that these are prudently managed through the AMA. However JGN notes that the AER has rejected the commercial margin payable to JAM under the AMA. As such JAM has

302 Draft decision, p. 317.

303 Draft decision, p. 365.

no commercial compensation for bearing this risk and would not agree to do so as a rational commercial firm.

In light of the above points, JGN's revised proposal includes the self insurance forecast established by MRC.

Site remediation

JGN has incorporated amendment 9.6 of the AER draft decision by deleting site remediation costs from its forecast opex.

Debt (and equity) raising costs

In this section JGN describes its forecast of debt and equity raising costs.

JGN incorporates the debt raising cost benchmark of 0.092 per cent adopted in the AER draft decision,[304] and the AER's proposed amendment to expense debt raising costs as incurred through the next regulatory period.

Debt raising costs are incurred each time debt is rolled over and may include underwriting fees, legal fees, company credit rating fees and transaction costs.

JGN does not incorporate the AER's proposed amendment with respect to equity raising costs and includes equity raising costs in its capital plan. This is because based on new forecast cost of service, equity raising cost assumptions and capital plan, JGN will not be able to cover its equity raising requirements through retained earnings alone.

This is discussed in more detail in section 3b.4.7.

Costs not deemed capital

JGN has responded to the AER's draft decision to deem certain proposed capex as opex in section 3b.4.3 of the forecast capex chapter. This reflects JGN's view as verified by E&Y, that these costs are capital in nature.

9.3.5 KPIs

Under rule 72(1)(f) of the NGR, the AAI for a full AA proposal must include the key performance indicators (KPIs) to be used by the service provider to support expenditure to be incurred over the AA period. JGN supplied proposed KPIs in section 6.8 of its AAI (table 6-14). The draft decision has not required any amendment to these KPIs. JGN considers that the current KPIs are adequate for opex (and capex) over the next AA period.

304 Draft decision, pp. 214-15.

9.4 Amendments to the access arrangement proposal and information

In light of the revised opex forecast set out in this chapter, JGN has amended the proposed AA as follows:

- updated inputs to X factor
- updated AUG forecast in UAG pass through provisions
- updated pass through for carbon permit costs.

10 Revenue

10.1 Summary of JGN original proposal

JGN's total required revenues for each year of the next AA period were set out in the following Table 10-1 from JGN's original AAI.

Table 10-1: JGN revenue requirement in its original AA proposal

Building block	2010-11	2011-12	2012-13	2013-14	2014-15
Return on capital	302.18	311.44	319.45	327.66	336.71
Return of capital (depreciation)	30.50	37.00	42.34	48.23	57.37
Opex	134.13	138.43	149.16	153.98	159.43
Revenue requirement	466.81	486.87	510.95	529.86	553.51

Having determined the total costs of JGN's service and revenue requirements, JGN allocated these costs and revenues between pipeline services.

JGN then specified price paths for its reference services to smooth its required revenue for the haulage reference service and achieve price stability over the next AA period. This smoothing gives rise to the price paths (P_0 and X factors) set out in section 13.8 of its original AAI.

10.2 Summary of AER draft decision

The AER draft decision considered that, in order to make the proposal acceptable to the AER, JGN would be required to amend the total revenue for each regulatory year of the AA period in its access arrangement proposal. The AER's replacement revenue requirement was provided at Table 10-2 of the draft decision (see below).

The main reasons for the difference in total revenue are:

- the AER not approving JGN's opening capital base and requiring amendments that would significantly reduce JGN's forecast capex
- the AER not approving JGN's opex
- the AER not approving JGN's WACC

Table 10-2: AER's conclusion on JGN's annual revenue requirements and X factors

Table 10.2: AER's conclusion on Jemena's annual revenue requirements and X factors ($m, real, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	231.6	233.5	234.9	236.3	237.5
Depreciation	29.9	35.5	40.6	44.4	50.4
Operating and maintenance	118.2	120.7	123.1	124.7	125.8
Corporate income taxation	10.3	10.8	11.1	11.6	12.4
Incentive mechanism payments	na	na	na	na	na
Total	390.0	400.4	409.7	417.0	426.1
X factor tariff revenue[a]					
Haulage reference service (%)	–1.23[b]	–1.96	–1.96	–1.96	–1.96
Ancillary fees (%)	0.0	0.0	0.0	0.0	0.0
Meter data service (%)	–42.49	0.0	0.0	0.0	0.0
Smoothed revenue path	378.8	394.2	410.0	425.1	439.0

Source: Table 10.2 is based on information from Part A of the draft decision.
a: Negative values for X indicate real price increases under the CPI–X formula.
b: X factor is P0 for the volume haulage reference service.

Table 10-3 sets out the amendments that the AER required in its draft decision in order to make the proposal accepted to the AER in relation to revenue.

Table 10-3: Amendments the AER required in its draft decision – revenue

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
10.1	Amend the AAI to delete table 12.1 and replace it with table 10.3 from the draft decision	Not incorporated. However relevant tables have been amended by reference to JGN's updated revenue forecast	Tables have been superseded by new AAI following updates to JGN data

10.3 JGN response to AER draft decision

As documented throughout this submission, JGN has responded to specifically to each cost of service building block item. The culmination of these responses and JGN's updated capex, opex, demand and WACC forecasts is the revenue requirement set out in Table 10-4.

Table 10-4: JGN revenue requirement (from August 2009 submission)

Building block	2010-11	2011-12	2012-13	2013-14	2014-15
Return on capital	258.22	266.31	273.42	280.87	289.26
Return of capital (depreciation)	25.88	32.05	37.86	44.87	53.00
Opex	138.17	140.89	145.53	148.96	153.64
Tax	21.81	24.43	26.01	29.46	33.39
Revenue requirement	**444.07**	**463.69**	**482.83**	**504.15**	**529.29**

10.4 Amendments to the access arrangement proposal and information

JGN has updated the revenue requirement table in section 11 of its revised AAI.

11 Demand forecasts

- JGN has commissioned updated independent demand forecasts from NIEIR incorporating actual gas consumption and customer data to January 2010, as well as updated economic drivers and (where necessary) updated policy impacts.
- The AER, in the draft decision, accepted the advice of its consultant, ACIL Tasman, that NIEIR's forecasting methodology was sound.
- JGN has adopted the updated NIEIR forecasts on the basis that they are 'arrived at on a reasonable basis' and 'represent the best forecast possible in the circumstances' (rule 74(2) of the NGR).

In its August 2009 original AA revision proposal JGN submitted gas demand forecasts prepared by the National Institute of Economic and Industry Research (**NIEIR**) specifically for JGN.

The NIEIR forecasts were produced in early 2009 based on econometric modelling and analysis as at December 2008. JGN made some adjustments to the NIEIR forecasts[305] for developments not able to be taken into account by NIEIR at the time of preparing the forecasts.

Table 11-1 of JGN's AAI summarised the adjusted NIEIR forecast as follows:

Table 11-1: JGN total gas forecast 2008-09 to 2014-15 (table 5-11 of JGN AAI)

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Total load (TJ)							
Residential	22,875	20,438	20,475	20,513	21,059	21,558	21,992
Business	12,227	12,072	11,961	11,966	12,128	12,451	12,777
Total volume customers	**35,102**	**32,510**	**32,435**	**32,480**	**33,187**	**34,010**	**34,769**
Demand customers	65,597	60,690	63,590	64,149	62,570	62,829	62,933
Total load	**100,699**	**93,200**	**96,025**	**96,629**	**95,757**	**96,838**	**97,702**
Customer numbers							

305 JGN increased the residential gas load figures by 150 TJ per year cumulatively commencing in 2009-10 as a result of its recently-introduced marketing plan. JGN also adjusted for a large new demand customer which commenced taking gas after the NIEIR model was developed.

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Residential	1,017,157	1,043,653	1,076,880	1,115,666	1,156,343	1,191,645	1,222,988
Small business	30,721	30,869	30,876	31,083	31,492	32,110	32,677
Total volume customers	**1,047,878**	**1,074,522**	**1,107,756**	**1,146,749**	**1,187,836**	**1,223,755**	**1,255,664**
Demand customers	421	423	424	424	424	425	426
New network connections							
New estates and high rise	17,095	21,280	26,954	31,565	33,655	28,495	24,768
Electricity to gas	4,988	5,215	6,273	7,220	7,022	6,807	6,575
Total new residential	**22,083**	**26,495**	**33,227**	**38,786**	**40,678**	**35,302**	**31,342**
Small business	881	975	1,075	1,175	1,251	1,335	1,410
Demand customers	3	3	3	3	3	3	3
HDD index standard							
HDD index	486	483	480	477	474	471	468
Average residential load per year (GJ)							
Existing customers	20.8	19.9	19.2	18.4	18.1	17.9	17.7
New estates and high rise	18.9	18.6	18.3	17.9	17.5	17.2	16.9
Electricity to gas	14.6	14.3	14.2	14.0	13.9	13.8	13.8
Average load all residential	20.8	19.4	18.7	18.0	17.7	17.5	17.2

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Maximum daily quantity demand customers (MDQ)							
MDQ demand customers	334.2	317.5	327.9	330.7	325.0	325.9	326.0

11.1 Summary of AER draft decision

The AER commissioned ACIL Tasman Pty Ltd (ACIL Tasman) to review the submitted JGN forecasts. ACIL Tasman undertook a desktop analysis into the methodology, data and parameters, and assumptions used to develop the demand forecasts[306].

The AER draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal to replace the detailed NIEIR econometric forecasts with ACIL Tasman forecasts based on a five year historical trend. Over the regulatory period the gas consumption forecasts prepared by ACIL Tasman are higher than the NIEIR forecasts by 9.9 per cent (volume customers) and 5.7 per cent (demand customers). Customer numbers and demand MDQ were unchanged in the draft decision.

The AER draft decision did not accept the forecasts submitted by JGN on the grounds that:

- JGN has not provided sufficient justification for the steepness of its proposed rate of decline in the average consumption per volume customer from the last year of the current AA period to the first year of the next AA period and subsequently over the next AA period
- JGN's proposed forecasts for demand users for the next AA period are understated and therefore do not reflect forecasts arrived at on a reasonable basis that represent the best estimate possible in the circumstances.

306 ACIL Tasman, p. 2.

Table 11-2 sets out the amendments that the AER required in its draft decision:

Table 11-2: Amendments the AER required in its draft decision – demand forecasts

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
11.1	Amend the AAI to delete table 5-11 (JGN total gas forecast 2008-09 to 2014-15) and replace it with the table provided at p251 of the draft decision	Partially incorporated	Sections 11.2 to 11.10

11.2 JGN response to AER draft decision

In producing its draft decision on JGN demand forecasts, the AER appeared to have exclusively relied on the ACIL Tasman analysis and the forecast methodology outlined in the ACIL Tasman report.[307] JGN has therefore done two things:

- reviewed the ACIL Tasman analysis and methodology for completeness, and in particular whether it would be capable of providing forecasts which are consistent with the requirements of the NGR;
- engaged NIEIR to review and update the assumptions previously used in its April 2009 forecasts, re-run its forecasting model and to update its forecasts where necessary.

JGN notes that Rule 74(2) of the NGR requires a forecast to be 'arrived at on a reasonable basis' and to 'represent the best forecast possible in the circumstances'.

JGN continues to hold the view that the NIEIR modelling approach produces forecasts which are arrived at on a reasonable basis and do represent the best forecasts available. The NIEIR model is highly detailed and takes into account all of the relevant drivers of gas demand. The NIEIR model has been accepted by regulators in the past and, indeed, ACIL Tasman acknowledges that it is methodologically sound. The fact that the model's outputs diverge from a linear historical trend is not a logical or cogent basis to conclude that the forecasts are not derived on a reasonable basis. On the contrary, this simply suggests that the model accounts for various factors, some of which may cause deviation from this trend. The AER's specific comments on the NIEIR model are addressed in section 11.4.

[307] Draft decision, p. 244 (volume customers) and p. 247 (demand customers).

In contrast, the ACIL Tasman forecasts adopted by the AER are not arrived at on a reasonable basis. Linear extrapolation of a historical trend is too rudimentary a tool for deriving forecasts, particularly where there are a range of variables which may potentially influence demand. Simple linear extrapolation will fail to account for non-linear changes in driver variables over time and will not reflect the introduction of new driver variables. JGN's concerns with the ACIL Tasman methodology are set out in section 11.5.

11.3 AER analysis of the NIEIR methodology

11.3.1 Volume customer forecasts

In its draft decision, the AER considered that the NIEIR forecasts were understated and expressed concern that JGN did not provide sufficient justification for the steepness of the rate of decline in per customer consumption[308].

JGN notes that the AER's consultants, ACIL Tasman, found the NIEIR forecasting framework to be sound and concluded that the forecasts were prepared 'using established and clearly described methodologies'. ACIL Tasman considered that the methodological approach of NIEIR was appropriate, and that the econometric estimation of a demand function (using income and prices and other exogenous variables and policies) was sound.[309]

However, the forecasts themselves were not acceptable to ACIL Tasman. ACIL Tasman's reasons (substantially relied upon by the AER) are summarised below. ACIL Tasman's primary concern with the volume customer forecasts was that they 'establish low starting points for the next access arrangement period'[310] and that this is out of line with historical trends.

ACIL Tasman suggests that the reason for this is the mix of government policies and consumer trends included in the NIEIR model which result in a step change in consumption. In ACIL Tasman's view, convincing reasons for this step change have not been presented by NIEIR.

ACIL Tasman commented:

- The weather normalised data shows a decline in average customer utilisation of around 0.29 GJ/pa.[311] The differential between the Jemena forecast and the weather-adjusted historical trend [is] between 1.6 and 3.0 GJ/a, or between 5 per cent and 10 per cent on average below the trend over the past five years[312].

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308 Draft decision, p.244.

309 ACIL Tasman, p. 20.

310 ACIL Tasman, p. 38.

311 JGN note: this is over the period 2004-05 to 2008-09.

312 ACIL Tasman, p. 29.

- [While] we see it as reasonable to expect that average consumption per Volume Customer will continue to decline in light of government policies and public opinion ---- these are not new trends: government policies relating to energy efficiency and more stringent building standards have been in place for some time and their effects on average gas consumption (particularly for new customers and new dwellings) are evident in the historical trends[313].

- We do not consider that any persuasive evidence has been put forward to support the step change in average customer consumption that is implicit in the Volume Customer forecast proposed by Jemena (and which is illustrated in the temperature adjusted actual versus forecast average gas consumption per customer shown in Figure 11. This is particularly true given that the forecast average demand reduction applies across all Volume Customers (more than 1 million) whereas the factors driving reduced average consumption are primarily associated with new customers and new dwellings[314].

- Jemena advised that actual Volume Customer consumption for the six months to end of December 2009 was 20.702 PJ and that, based on the percentages of actual 2008–09 billings for residential and small business customers that occurred in the second six months of that year, Jemena now expects total Volume Customer sales in 2009–10 to reach 32.721 PJ. However, we note that the 2008-09 year was significantly colder than average ------ As a result we would expect that the proportion of total gas consumption in 2008–09 occurring in the first half of the year would have been higher than usual because of the increased winter heating load. As a result, using 2008–09 data on the split between the first and second halves of the year as the basis for estimating consumption in the second half of 2009–10 is likely to significantly understate second half consumption[315].

- On this basis we recommend that the Volume Customer demand forecast should be adjusted upward to reflect an average rate of consumption per customer consistent with the trend line shown in Figure 11[316].

11.3.2 Demand customer forecasts

The AER also considered the NIEIR forecasts for demand customers to be understated. The AER notes in particular a significant drop in consumption forecast by NIEIR at the beginning of the next AA period, as illustrated below[317].

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313 ACIL Tasman, p. 31.

314 ACIL Tasman, p. 31.

315 ACIL Tasman, p. 32.

316 ACIL Tasman, p. 32.

317 Draft decision, p. 247.

Table 11-3: JGN demand customer forecast (from Table 11-1 above)

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Total load (TJ)							
Demand customers	65,597	60,690	63,590	64,149	62,570	62,829	62,933

On this point, ACIL Tasman commented:

- A sharp drop in gas consumption in the Demand Customer sector—around 4.4 PJ/a or some 6.8 per cent—is forecast for the 2009–10 year. Given that the forecast in this year effectively sets the starting point for the subsequent access arrangement period, it is important to investigate the reasons why the NIEIR modelling produced this result[318].

- In December 2008, the ultimate effects of the GFC in Australia were uncertain and NIEIR considered a relatively pessimistic scenario[319]

- In light of the performance of the Australian economy during 2009 and the apparent efficacy of the government stimulus measures, the macroeconomic indicators for Australia and for NSW in particular may well prove more favorable than assumed in the NIEIR report[320].

In coming to its conclusion, the AER also referred to the ACIL Tasman comparison of the NIEIR forecasts for 2009-10 with an updated demand estimate for that period. ACIL Tasman's report provided additional market analysis to illustrate that the 2009-10 demand customer consumption forecast was too low[321].

ACIL Tasman concluded:

> Thus the evidence of actual consumption to the end of 2009 now suggests that Demand Customer load in 2009–10 will be some 3.6 PJ higher than the NIEIR forecast.
>
> Accordingly, we propose that a better forecast of Demand Customer consumption would be obtained by extrapolating the past five years of historical data on linear trend (weather normalized). This would yield the alternative forecast shown in Figure 14 and Table 7[322].

318 ACIL Tasman, p. 33.

319 ACIL Tasman, p. 18.

320 ACIL Tasman, p.19.

321 ACIL Tasman, p. 35; Draft decision, pp. 246-247.

322 ACIL Tasman, p.36.

11.4 JGN response to AER analysis

11.4.1 Volume customer forecasts

The NIEIR model has been used by a range of electricity and gas businesses as well as by regulators. NIEIR has over 30 years' experience in economic and energy sector forecasting, and has a large client base including most energy networks in Australia. NIEIR has been used frequently by planning bodies such as VENCorp and ESIPC (both now part of AEMO), and in jurisdictional electricity transmission planning. NIEIR has had a key role in preparing material for the annual Statement of Opportunities for NEMMCO (now AEMO) and forecasts for VENCorp's Gas Annual Planning Review. NIEIR also prepares annual gas forecasts for gas networks in Western Australia, Queensland, South Australia and Tasmania.

One of the key attributes of the NIEIR model is its granularity. ACIL Tasman offers a broad endorsement of the NIEIR methodology for forecasting demand. The NIEIR forecasting model is able to take into account differences in a range of variables between regions and sectors.

Despite endorsing the NIEIR methodology, the AER and ACIL Tasman have questioned whether the demand drivers in the NIEIR model could reasonably be expected to result in the decline in average usage per volume customer evident in the NIEIR forecasts[323]. This reflects their view that the historical data should have already picked up the impacts of public policy variables related to energy efficiency. This point is addressed immediately below.

Historical trends in average consumption

JGN disagrees with the ACIL Tasman contention that all government policies relating to energy efficiency and their effects on average gas consumption are fully evident in the historical trends and therefore that there should be no 'step change' in the trend of average consumption over the 2010-11 to 2014-15 regulatory period as compared with recent history[324].

Three significant Government programs have either been substantially changed in the last 12 months or will be implemented in the coming year, namely:

- the home insulation scheme
- the home solar rebate
- minimum energy performance standards (MEPS) for gas hot water systems

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323 ACIL Tasman, p. 29; Draft decision, p. 244.

324 ACIL Tasman, p. 38.

Significant changes to both the home insulation and home solar schemes were announced and implemented in February 2009 as a part of the Federal Government GFC stimulus measures. The changes removed means testing of rebates and substantially reduced the amounts payable by consumers to install insulation or solar boosted hot water system. This resulted in dramatically increased installation of these products into existing and new dwellings.

The introduction of MEPS for gas hot water systems was proposed in the 2008 National Hot Water Strategic Framework, and was confirmed in the recently released regulatory impact statement for the greenhouse intensive water heater phase-out program to be implemented in 2011. Currently, consumers are able to replace existing gas systems with any available gas model. The introduction of MEPS for gas hot water systems will result in the removal of all lower efficiency units from the market and will substantial increase the efficiency of replacement hot water systems by at least 15 per cent for basic models.

With regard to ACIL Tasman's contention on historical trends, reduced energy consumption resulting from the significant increase in home insulation and solar hot water systems driven by the stimulus package during 2009 would not be included in the historical trends. Likewise, the demand impacts on existing customers as a result of the introduction of MEPS for gas hot water systems proposed in 2011 obviously cannot be discerned yet.

Volume consumption in 2009-10

ACIL Tasman drew attention to the cool 2008-09 year, and the possibility that this may have understated the JGN estimate provided to the AER for 2009-10, given that JGN relied upon that year for its estimate. This comment is now unnecessary, given that NIEIR has produced a revised series of historical and forecast weather normalised volume consumption, including the years 2008-09 and 2009-10. In doing so, NIEIR has relied upon updated historical data provided by JGN (to January 2010). See section 11.7 below.

11.4.2 Demand customer analysis

Similar to the volume customer forecasts, no objection has been raised to the NIEIR methodology for deriving demand forecasts. Rather, ACIL Tasman and the AER have pointed to the discrepancy between the NIEIR forecast for 2009-10, and actual data for the six months to December 2009 and an updated forecast for 2009-10, both of which were provided by JGN in response to an AER request[325].

JGN submits that the NIEIR forecasts in their entirety should not be dismissed by the AER based on the understatement of just one year during a period of

325 ACIL Tasman, p. 36; Draft decision, p. 246.

unprecedented economic uncertainty. The basis for the forecasts is sound and the forecasting model used by NIEIR is robust.

However, JGN acknowledges that the NIEIR forecast is now almost a year old and does need to be informed by updated inputs, including actual data for 2009 and updated data for 2009-10. This is addressed in section 11.7.

11.5 Alternative forecasts proposed by the AER

JGN disagrees with the AER requirement that the demand forecasts should be adjusted upward to reflect an average rate of consumption per customer consistent with the ACIL Tasman recommendations, based on trend extrapolation.

JGN considers that a simple linear extrapolation of historic trends is not a reasonable basis for arriving at demand forecasts and therefore would not be consistent with the requirements of the NGR. Linear extrapolation runs the risk of producing inaccurate forecasts since it will (among other things)::

- fail to account for non-linear movements in any driver variable
- ignore non-linear relationships between any driver variable and demand
- fail to account for one-off events with ongoing demand impacts (e.g. changes in government policy).

In the context of gas demand forecasting, linear extrapolation is likely to be particularly problematic given the range of potential demand drivers and the interaction between them. Any forecast will need to take into account factors such as macroeconomic conditions, price elasticity, substitution to other energy sources, changes in government policy and so on. The ACIL Tasman extrapolation takes none of these factors into account, except to the extent that that they are evident in historic trends. JGN submits that this is not a reasonable basis for arriving at forecasts of demand.

JGN's specific concerns with the ACIL Tasman forecasts for volume customers and demand customers are set out below.

11.5.1 Volume customer demand (based on extrapolation)

Conceptually, the ACIL Tasman volume customer demand forecast can be thought of as having only two inputs:

- a forecast of volume customer numbers

- a linear extrapolation of the trend in weather-normalised average consumption per volume customer established over the five years to 2009[326].

The AER draft decision proposed to rely on simple extrapolation of a five year historical trend as one of only two inputs to a forecast which determines tariffs that will account for approximately 90 per cent of JGN's forecast revenue over the regulatory period.

Simple extrapolation may be acceptable as the basis for forecasting a minor component of, or a low level factor used in building up a forecast of total costs or volumes. As far as JGN is aware, there is no regulatory precedent in Australia (under the current or previous gas regulatory regime) for extrapolation to be used at the high level proposed by ACIL Tasman and accepted by the AER. Even if it was appropriate to consider the use of extrapolation at such a high level in the current circumstances, the AER should not accept ACIL Tasman's simple statistical regression without:

- explaining how simple extrapolation can be considered an adequate substitute for the rigorous approach used in NIEIR detailed modelling; and
- adequately analysing the reliability and precision of ACIL Tasman's regression equation.

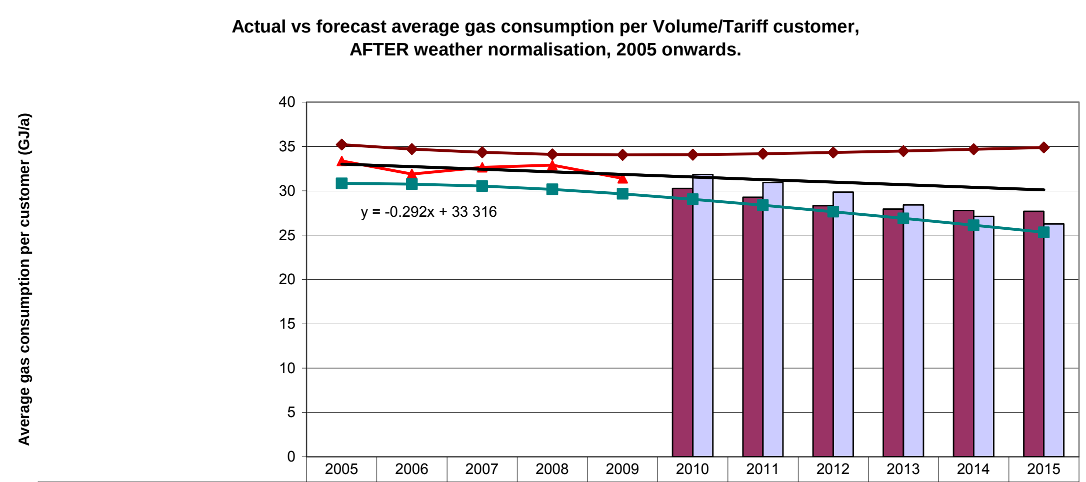
Precision of ACIL Tasman regression

Table 11-4:below is adapted from ACIL Tasman's figure 11. It shows:

- forecast average consumption per volume customer from 2009-10 onwards based on JGN's August 2009 submission (dark coloured upright bars). This is labelled as 'JGN forecast April 09'
- forecast average consumption per volume customer from 2009-10 onwards based on NIEIR's updated forecast provided to JGN as part of this response (light coloured upright bars). This is labelled as 'JGN forecast Feb 10'
- weather normalised historic average consumption from 2005 to 2009 (as recorded by ACIL Tasman)
- the regression of the historic data from 2005 to 2009 and its extrapolation to 2015 (similar to the ACIL Tasman regression)
- the upper and lower limits of the 90 per cent confidence band around the extrapolated regression

[326] In contrast, ACIL Tasman analysed 149 years' data to confirm that 'the NIEIR assumption in relation to HDD decline appears to be reasonable' (ACIL Tasman p 22).

Table 11-4: Actual and forecast gas consumption per volume customer



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
JGN Forecast April 09						30.26	29.28	28 32	27.94	27.79	27 69
JGN Forecast Feb 10						31.84	30.95	29 85	28.41	27.11	26 26
AC L Tasman Fig 11 (final report)	33.36	31 89	32.66	32.89	31.4						
Linear Trend: data to 2009	33.02	32.73	32.44	32.15	31 86	31.56	31.27	30 98	30.69	30.40	30.10
Upper 90% for prediction	35.22	34.71	34.34	34.13	34 05	34.08	34.17	34 32	34.49	34.68	34 88
Lower 90% for prediction	30.83	30.75	30.54	30.17	29 66	29.05	28.37	27 64	26.89	26.11	25 32

Year

Source: JGN.

JGN finds that the ACIL Tasman regression equation is not statistically significant because:

- the coefficient of determination (r^2) is not significantly different from zero
- the gradient of the ACIL Tasman regression line is not significantly different from zero

The values based on both the April 2009 and February 2010 NIEIR reports are within the 90per cent confidence band around the extrapolated ACIL Tasman regression line in every year of the forecast (i.e. the top of each bar is above the lower limit of the confidence band).

JGN concludes that statistically, it cannot be claimed with any confidence that either of NIEIR's forecasts is inconsistent with the historical data. In other words, the ACIL Tasman extrapolation does not produce a forecast of average consumption per volume customer that is statistically better than that derived from the more robust NIEIR forecast. Moreover, the different result produced by simple extrapolation of a linear trend does not provide a *prima facie* basis for rejecting the NIEIR forecast which is produced by a detailed methodology which ACIL Tasman has itself endorsed.

Extrapolation at the disaggregated level

Even if trend extrapolation was considered an acceptable forecasting methodology, the question must be asked whether ACIL Tasman's gross approach is the best available in the circumstances. In JGN's view it is not. The volume market has three distinct components:

- existing residential customers
- new residential customers, comprising transfers from electricity to gas (E to G) and new homes
- business customers.

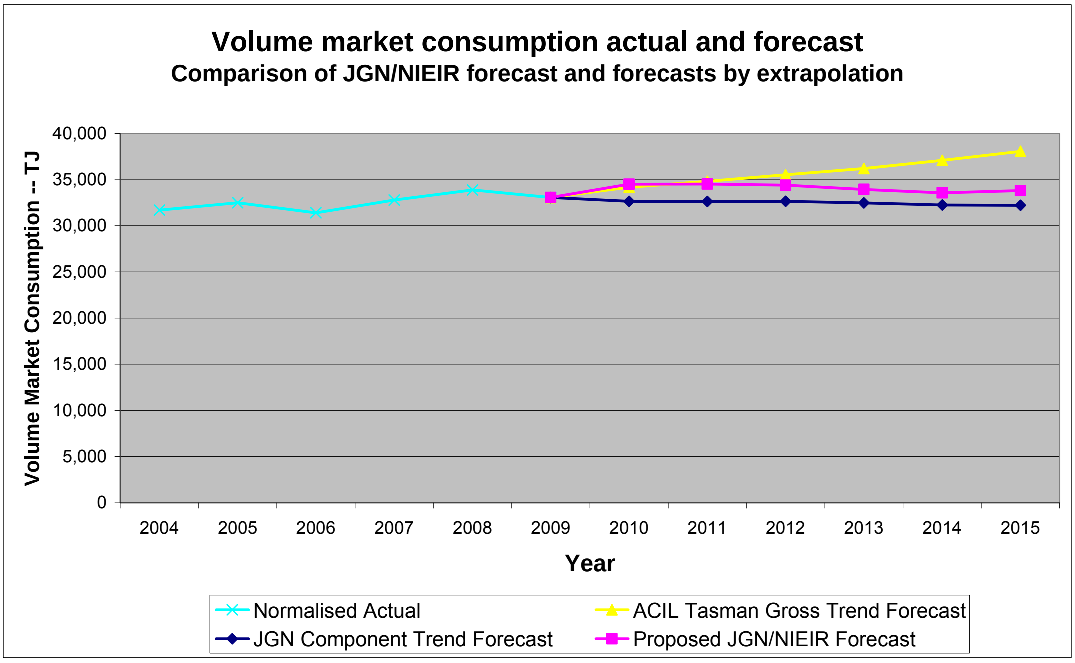
Between them, over one million existing and new residential customers account for approximately two thirds of volume market consumption and the 30,000 business customers account for the remaining one third. The three components each have very different characteristics and drivers.

If the forecast is to be developed by extrapolation then, to be as rigorous as possible, the approach should be applied at the level of the relevant market components and the resulting components aggregated into a total. To illustrate the inadequacy of the ACIL Tasman extrapolation, JGN has developed its own extrapolation at a more disaggregated level. In building up this extrapolation-based forecast JGN has extrapolated trends for:

- average consumption per E to G customer
- average consumption per new home customer
- the number of existing (as at 2003) residential customer
- aggregate load for existing (as at 2003) residential customers
- average consumption per business customer

When these extrapolated trends are combined with forecast numbers of customers, the resultant forecast consumption for the volume market is lower than both NIEIR and ACIL Tasman as shown in Table 11-5.

Table 11-5: Actual and forecast gas consumption per volume customer



Source: JGN.

In JGN's view, if extrapolation is to be the basis for forecasting, this result has a much stronger analytical foundation than ACIL Tasman's. ACIL Tasman's gross extrapolation forecast is also shown on the graph along with the JGN/NIEIR forecast which JGN proposes to adopt:

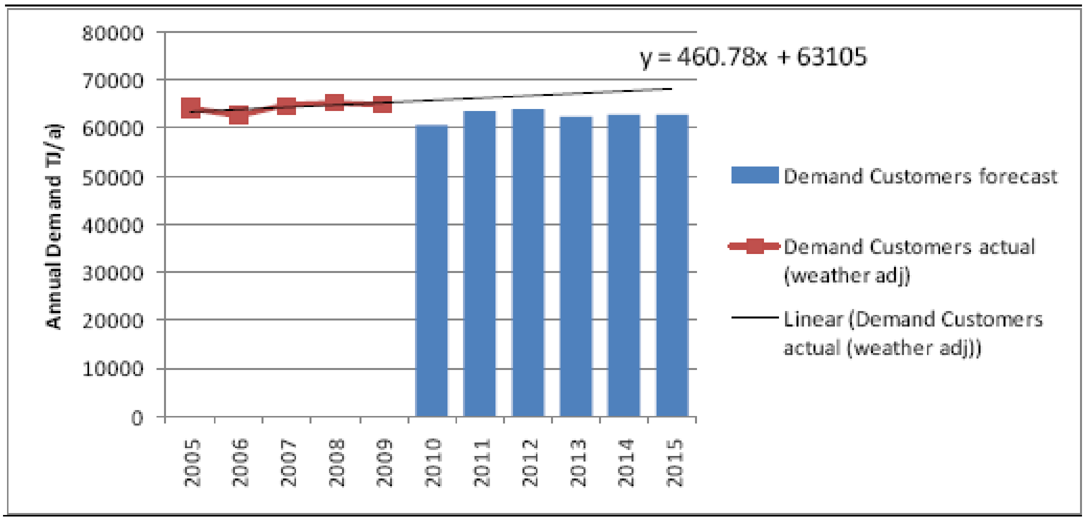
11.5.2 Demand customer analysis

As noted in section 11.4.2, JGN provided additional information to the AER for demand customers subsequent to the JGN submission, including actual consumption to December-2009.

In the light of actual data, it would appear that the original NIEIR demand customer consumption forecast was understated for 2009-10. However, this does not immediately suggest that the whole of the JGN/NIEIR forecast for subsequent years should be uplifted by some arbitrary factor as proposed by ACIL Tasman.

ACIL Tasman's figure 14 uses the same technique as for its volume forecast – an extrapolation of five years' history:

Table 11-6: Actual and forecast demand customer demand



Data source: Jemena Access Arrangement Information

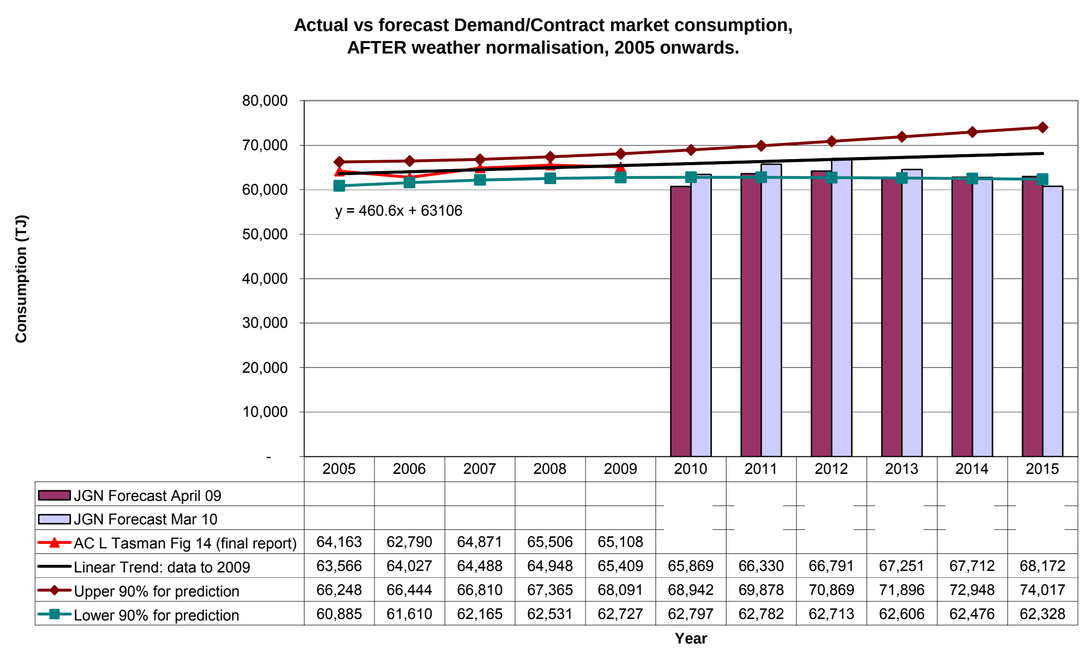
Source: ACIL Tasman.

JGN notes that the same objection can be raised as with ACIL Tasman's volume forecast. That is, the different result produced by simple extrapolation of a linear trend does not provide a *prima facie* basis for replacing the NIEIR detailed methodology.

Further, as JGN has demonstrated in relation to the volume customer forecast, NIEIR's demand forecast values (updated for 2009-10) lie within the 90 per cent confidence band around the extrapolated ACIL Tasman regression line (as shown in Table 11-7).

Commercial in confidence

Table 11-7: Actual and forecast demand customer demand



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
JGN Forecast April 09											
JGN Forecast Mar 10											
AC L Tasman Fig 14 (final report)	64,163	62,790	64,871	65,506	65,108						
Linear Trend: data to 2009	63,566	64,027	64,488	64,948	65,409	65,869	66,330	66,791	67,251	67,712	68,172
Upper 90% for prediction	66,248	66,444	66,810	67,365	68,091	68,942	69,878	70,869	71,896	72,948	74,017
Lower 90% for prediction	60,885	61,610	62,165	62,531	62,727	62,797	62,782	62,713	62,606	62,476	62,328

Source: JGN.

Finally, JGN suggests that using ACIL Tasman's figure 14 as a basis of a recommendation to the AER to uplift the JGN demand customer forecast by the recommended quantities appears questionable. ACIL Tasman's analysis went to considerable lengths to update the total JGN forecast for 2009-10 on the basis of data at December 2009 and concluded that:

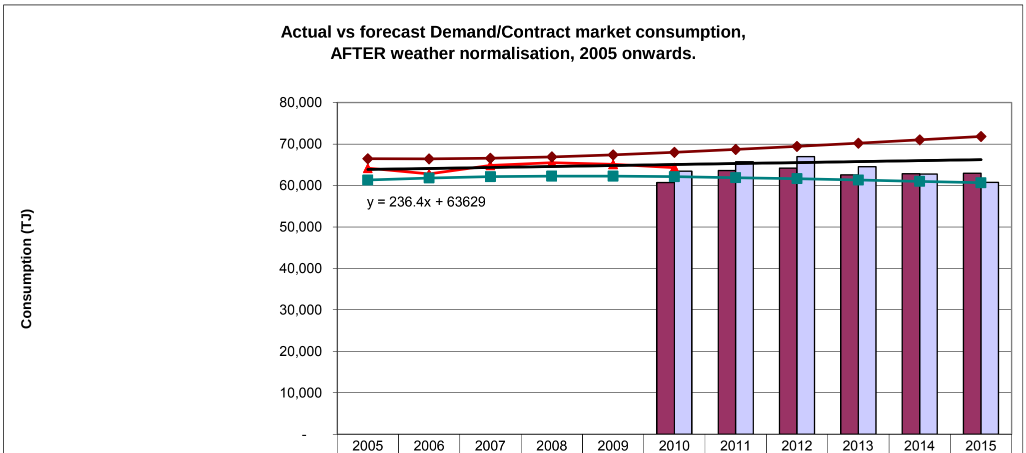
> Thus the evidence of actual consumption to the end of 2009 now suggests that Demand Customer load in 2009-10 will be some 3.6 PJ higher than the NIEIR forecast[327]

On ACIL Tasman's reckoning, a figure closer to 64,300 TJ was likely for 2009-10, and JGN's own estimate supplied to the AER supported this. Yet ACIL Tasman persisted in conducting its analysis by reference to the outdated figure of 60,690 TJ. If the latter had been updated and made part of the regression, the regression line would be much flatter, so that the case for boosting the JGN/NIEIR forecast would have been much weaker. JGN has undertaken this analysis as shown in Table 11-8:

[327] ACIL Tasman, p. 36.

Commercial in confidence

Table 11-8: Actual and forecast demand customer demand



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
JGN Forecast April 09											
JGN Forecast Mar 10											
ACIL Tasman Fig 14 (final report) + 2010	64,163	62,790	64,871	65,506	65,108	64,300					
Linear Trend: data to 2010	63,865	64,102	64,338	64,575	64,811	65,047	65,284	65,520	65,757	65,993	66,229
Upper 90% for prediction	66,426	66,410	66,556	66,883	67,372	67,981	68,671	69,414	70,192	70,993	71,811
Lower 90% for prediction	61,304	61,793	62,120	62,266	62,250	62,113	61,896	61,626	61,321	60,993	60,648

Source: JGN.

Replacing the original JGN forecast for 2009-10 with 64,300 TJ results in:

- a flatter regression line, indicating growth in forecast annual consumption of 236 TJ per year compared with 460 TJ per year under ACIL Tasman's original regression
- the projections for the four years from 2009-10 to 2012-13 being either exactly on the regression line or close to it
- a narrower 90 per cent confidence band around the regression line
- JGN's revised March 2010 forecast lying comfortably within the 90 per cent confidence band.

11.6 Review and update by NIEIR

As noted in section 11.2, JGN engaged NIEIR to review and update the assumptions previously used in its April 2009 forecasts, to re-run its forecasting model and to update its forecasts where necessary. The revised forecasts are included in an updated NIEIR report included as Appendix 11.1 in this JGN response to the draft decision.

NIEIR have advised JGN that:

- NIEIR has updated all of the economic drivers, the actual (historical) customer numbers, and volumes
- forecasts for 2009-10 are grossed up to June 2010 using actual date to January 2010
- NIEIR has taken into account the revised Federal Insulation scheme, but that other policy impacts have remained as previously assessed (including that the Treasury CPRS-5 scenario will apply out to 2015).

11.7 Results of NIEIR update

11.7.1 Economic

Noting that 'the economic mood has shifted considerably since early in 2009'[328] NIEIR has produced revised growth scenarios for Australia and NSW. These are shown in Table 11-9:

Table 11-9: NIEIR revisions to Australian Gross Domestic Product growth and NSW Gross State Product growth– year ending 30 June (per cent per year)

NIEIR projections	2009	2010	2011	2012	2013	2014	2015
Australia GDP							
April 2009	0.7	0.6	1.8	4.5	3.8	3.5	2.9
March 2010	1.0	1.2	2.2	4.6	2.8	1.7	1.8
NSW GSP							
April 2009	-0.9	-1.7	0.3	4.6	3.5	2.9	2.4
March 2010	0.0	0.3	1.4	4.9	2.2	0.9	0.5

Commenting on NSW growth performance, NIEIR says:

> As was expected in our previous report, economic conditions in New South Wales during 2008-09 were tough[329]. New South Wales gross state product grew by a meagre 0.04 per cent in 2008-09. However, the impact of the global economic recession on the New South Wales economy has not been as severe as was expected. In our previous report, New South Wales gross state product was predicted to contract by 0.9 per cent in 2008-09.

328 NIEIR, *Natural Gas Projections NSW Jemena Gas Networks to 2015,* March 2010 p. 5.

329 The previous economic projections were prepared in March 2009 after the Commonwealth stimulus package had been announced but before the package of measures announced as part of the Commonwealth Budget in May 2009.

> The better-than-expected outcome can be attributed to the quick actions of Australian fiscal and monetary policy makers in bolstering consumer confidence which had been on the verge of collapse in aftermath of the global financial crisis. Remarkably, household expenditure in New South Wales grew in 2008-09 and dwelling investment did not fall as sharply as was expected.
>
> While the main shocks of the global economic recession appear to be behind us, the New South Wales economy is not out of the woods yet. It is only expected to record a very modest improvement in growth in the current financial year. New South Wales gross state product is projected to grow by just 0.3 per cent in 2009-10 (albeit a substantial improvement on the 1.7 per cent contraction projected in our previous report) [330].

NIEIR expects the recovery in economic growth in New South Wales to begin to pick up pace in 2010-11 before accelerating considerably in 2011-12. However, the unwinding of the Commonwealth Government fiscal stimulus and a reversal of expansionary monetary policy is expected to significantly slow economic growth in New South Wales during 2012-13 and 2013-14. Economic growth is not expected to recover again until after 2014-15.

In view of the updated economic outlook described above, JGN considers that ACIL Tasman's contention that "NIEIR considered a relatively pessimistic scenario'[331] can not be applied to NIEIR's March 2010 forecasts.

11.7.2 Modelling approach

NIEIR has not changed the modelling approach used is its April 2009 report for JGN. Modelling is described in sections 4.1 to 4.6 of NIEIR's March 2010 report.

All gas quantity forecasts have been weather normalised, as described in section 4.4 of the latest NIEIR report.

11.7.3 Policy initiatives affecting gas consumption

As with its 2009 forecasts for JGN, NIEIR evaluated a number of federal and state government policies and initiatives related to energy use and gas consumption. These included:

- the BASIX water and energy conservation program for new NSW homes as implemented in July 2006
- the program to review and standardise energy labelling of gas appliances, together with the development of mandatory energy performance standards (**MEPS**) for new gas appliances

[330] NIEIR, pp 22-23.

[331] ACIL Tasman, p. 18.

- the increased penetration of energy efficient showerheads
- national hot water strategic framework—the effective banning of electric resistance hot water appliances from 2012
- the ongoing negative impact of high sales of reverse cycle air conditioning equipment
- the Commonwealth Government stimulus package with subsidies for home insulation
- other new policies or developments, such as the new NSW Energy Efficiency Target scheme (**NEET**) and the RET scheme.

These policies are discussed in detail in section 4.8 of the NIEIR report.

Regarding the Commonwealth Government subsidies for home insulation, JGN notes that although the Energy Efficient Homes Initiative has been suspended, its effects will linger for some time. NIEIR had been forecasting a 50 per cent take-up in 2009-10 in uninsulated gas heated dwellings. However, the annual take-up is forecast to decrease given uncertainty surrounding the future of the scheme, and as backlog applications are completed.

11.8 JGN adjustments to NIEIR forecasts

11.8.1 Large new demand customer

As noted in its original proposal, JGN adjusted the April 2009 NIEIR forecast to account for a large new demand customer which commenced taking gas in January 2009. While this customer is now part of the established customer base, JGN has again kept this customer separate from the main demand customer forecast because all consumption history to the end of 2009 reflects performance testing and commissioning of the plant associated with construction and handover. From 2010-11 onwards, the customer is expected to have the steady annual load previously forecast in JGN's original proposal. The tables below adjust the NIEIR forecast for the customer's annual gas consumption and MDQ.

Table 11-10: Adjustment to annual gas consumption demand customers (TJ) – year ending 30 June

	2009	2010	2011	2012	2013	2014	2015
Total	**64,568**	**64,643**	**65,936**	**67,183**	**64,765**	**62,942**	**60,969**

Commercial in confidence

Table 11-11: Adjustment to forecast MDQ demand customers (TJ) – year ending 30 June

	2009	2010	2011	2012	2013	2014	2015
Total	**330.6**	**318.0**	**326.2**	**331.3**	**322.3**	**315.7**	**308.4**

11.8.2 Forecast residential marketing adjustment

JGN included in its original AAI proposal an additional 150TJ per annum growth on top of the NIEIR residential consumption forecast to account for the recently established *Natural Gas The Natural Choice* marketing program. The additional volumes were based on the marketing campaign and incentive costs of $8.2 million per annum proposed in the AAI submission. In its draft decision the AER rejected the proposed increase in marketing costs above base year costs for the next AA period (amendment 9.4). The reduction in marketing costs will have a direct impact on the levels of growth achieved as a result of the marketing program, and JGN proposes to reduce the marketing growth proportionally down to an extra 120TJ per annum (cumulative).

Table 11-12: Marketing growth adjustment for residential volume customer (terajoules) – comparison of 2009 AAI and 2010 resubmission

	2010	2011	2012	2013	2014	2015
AAI 2009	150	300	450	600	900	1050
Resubmission 2010	60*	180	300	420	540	660

* 2010 forecast is based on 6 month actual volumes and 6 month forecast

Table 11-13: Adjustment to annual gas consumption volume customers (TJ) – year ending 30 June

	2010	2011	2012	2013	2014	2015
NIEIR	22,424	22,302	21,926	21,489	21,372	21,568
Marketing adjustment	60	180	300	420	540	660
Total	**22,484**	**22,482**	**22,226**	**21,909**	**21,912**	**22,228**

11.8.3 Small business and demand customer new connections adjustment

The NIEIR model for small business and demand customer numbers is based on total market movements, and hence the numbers provided as part of its forecasts are net figures; i.e. new connections less disconnections. In its original AAI proposal, JGN separately estimated the number of new small business and demand customer connections. Updated numbers are shown in Table 11-14.

Table 11-14: Number of new connections small business and demand customers – year ending 30 June

	2009	2010	2011	2012	2013	2014	2015
Small business	888	975	1,075	1,175	1,251	1,335	1,410
Demand customer	6	3	3	3	3	3	3

11.9 Other demand issues

11.9.1 Pipeline capacity and utilisation

The draft decision says:

> The AER notes that Jemena provides no information on capacity and utilisation. The AER acknowledges that a distribution network is a meshed network made up of interconnected pipes and there are a number of practical considerations governing why the calculation of utilisation is not straightforward, and so therefore may not be practicable. [332]

JGN acknowledges that, through an oversight, its access arrangement information did not specifically address the issue of pipeline capacity and utilisation, even though this is a requirement under NGR 72(1)(d).

As a matter of record, JGN now submits that *capacity and utilisation information* is not available or meaningful for a distribution pipeline.

11.9.2 Maximum, minimum and average demand

The draft decision says:

> As shown in Table 11.2, while Jemena submits average, minimum and maximum daily demand figures for the first four years of the earlier access arrangement period it does not provide for minimum and maximum daily demand of the total system[333].

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332 Draft decision, p. 251.

333 Draft decision, p. 235.

JGN is concerned that this statement could convey the impression that JGN deliberately withheld this information. However, as is made clear in the footnote to table 4-2 in JGN's submitted AAI:

> JGN does not have available forecasts of maximum and minimum total system wide demand, which is why the above table presents historical data.[334]

11.9.3 Updated 2009-10 forecasts

The draft decision says:

> While Jemena revises upwards its forecasts for 2009–10, the last year of the earlier access arrangement, it makes no revisions to the original forecasts for the access arrangement period[335]

JGN is concerned that this statement could convey the impression that JGN should have revised its forecasts beyond 2009-10. JGN makes two comments:

- it needs to made clear that JGN was requested by the AER to provide updated information only for 2008-09, the six months to December 2009 and estimates for 2009-10[336]. There was no AER requirement for JGN to provide additional forecasts.

- at the time of the AER request, JGN had not commissioned updated forecasts from NIEIR, and so had no basis for additional forecasts.

11.10 Amendments to the access arrangement proposal and information

AER amendment 11.1 required JGN to amend table 5-11 of its AAI in accordance with the high-level extrapolations of ACIL Tasman. Those extrapolations are given in Table 11-15 and Table 11-16 of the draft decision, and summarised below:

Table 11-15: Amendments the AER required in its draft decision –volume and demand customers *(from tables 11.5 and 11.6 draft decision)*

	2010-11	2011-12	2012-13	2013-14	2014-15
Volume customers (TJ)	34,967	35,864	36,804	37,561	38,175
Demand customers (TJ)	65,870	66,330	66,791	67,252	67,713

334 JGN AAI, p. 43.

335 Draft decision, p. 235.

336 AER, request for further information on demand, 8 December 2009.

AER amendment 11.1 (as described on pages 252-253 of the draft decision) also required an update of actual 2008-09 gas quantities and customer numbers, as supplied to the AER by JGN.

While JGN can see how the ACIL Tasman quantities in Table 11-15 above have been applied in amendment 11.1, JGN is unclear how AER amendment 11.1 was able split the volume customer forecasts into residential and small business quantities, given that the ACIL Tasman report showed only total volume customer gas quantities. JGN is also unclear how amendment 11.1 arrived at revised customer numbers for 2009-10, since these were not addressed in the ACIL Tasman report.

Equally, JGN cannot see how amendment 11.1 arrived at forecasts of average consumption per customer divided into existing residential customers, new estates/high rise customers and E to G customers for each year of the forecast, given that the ACIL Tasman report provided only forecasts of average consumption for volume customers in total.

As described in sections 11.3 to 11.5 above, JGN has analysed the ACIL Tasman extrapolations in depth and for the reasons given, concludes that they do not represent forecasts arrived at on a reasonable basis which reflect the best estimate possible in the circumstances, in accordance with NGR 74. JGN has therefore not implemented amendment 11.1 to the extent that it reflects the ACIL Tasman extrapolations or any AER estimates (presumably based on ACIL Tasman).

In the revised AA revision, JGN has addressed the matter raised by the AER in the draft decision as to the time at which the forecast had been prepared and the date of the relevant data inputs to the forecast. To the extent the AER had concerns about the time at which the forecast was prepared and the data of the data inputs to the forecast, the change necessary to correct any perceived non-compliance in this regard is to update the NIEIR forecasts, JGN has done this and therefore this element of its proposal is consistent with the requirements of the NGL and NGR.

Instead, as described in sections 11.6 and 11.7, JGN commissioned an updated forecast from NIEIR which incorporated actual gas consumption and customer data to January 2010, and which included updated economic drivers and (where necessary) updated policy impacts.

JGN has implemented the updated NIEIR forecast (amended in accordance with section 11.8 above) as follows:

Table 11-16: Amended JGN total gas forecast 2008-09 to 2014-15 (table 5-11 of JGN AAI)

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Total load (TJ)							
Residential	21,310	22,518	22,553	22,335	22,055	22,105	22,474
Business	11,753	12,039	12,148	12,359	12,296	12,004	11,992
Total volume customers	**33,063**	**34,557**	**34,700**	**34,694**	**34,351**	**34,110**	**34,466**
Demand customers	64,675	64,643	65,936	67,183	64,765	62,942	60,969
Total load	**97,738**	**99,200**	**100,637**	**101,878**	**99,116**	**97,052**	**95,436**
Customer numbers							
Residential	1,022,084	1,052,085	1,082,658	1,115,918	1,148,907	1,189,233	1,233,758
Small business	29,750	30,210	30,496	30,961	31,082	30,911	31,045
Total volume customers	**1,051,834**	**1,082,295**	**1,113,154**	**1,146,879**	**1,179,989**	**1,220,144**	**1,264,802**
Demand customers	**414**	**411**	**412**	**412**	**410**	**409**	**409**
New network connections							
New estates and high rise	18,197	22,945	24,306	26,067	26,016	33,554	37,956
Electricity to gas	6,332	7,056	6,267	7,193	6,973	6,772	6,568
Total new residential	**24,529**	**30,001**	**30,573**	**33,260**	**32,989**	**40,326**	**44,524**
Small business	888	975	1,075	1,175	1,251	1,335	1,410
Demand customers	6	3	3	3	3	3	3
HDD index standard							
HDD index	496	490	484	479	473	468	462

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Average residential load per year (GJ)							
Existing customers	20.4	21.5	20.9	20.1	19.2	18.5	18.2
New estates and high rise	18.1	17.0	16.7	16.1	15.3	14.7	14.3
Electricity to gas	14.6	14.6	15.7	14.8	14.1	13.6	13.3
Average load all residential	**20.8**	**21.3**	**20.7**	**19.7**	**18.8**	**18.1**	**17.7**
Maximum daily quantity demand customers (MDQ)							
MDQ demand customers	**331**	**318**	**326**	**331**	**322**	**316**	**308**

12 Tariffs – distribution pipelines

- JGN welcomes the AER's acceptance of its reference tariff for volume customers who account for 99 per cent of customers and 88 per cent of revenue.
- JGN does not agree with the AER's draft decision findings regarding the minimum bill and demand first response tariff components for demand customers.
- JGN has amended its haulage reference tariffs and meter data service reference tariffs to include charging parameters which incorporate ancillary fees as part of these reference services.
- JGN has made a further amendment to add a new demand tariff category "Major End-Customer Throughput" to cap the step change impacts of price changes for larger demand customers in the Sydney region arising from structural changes to tariffs to accommodate the STTM hub design.

12.1 Summary of JGN original proposal

In its original AA proposal, JGN maintained its existing reference tariff structures for all volume customers, which represent 88 per cent of revenue as at 31 March 2009.

JGN's remaining customers, who account for 12 per cent of JGN's revenue and 0.04 per cent of customers as at 31 March 2009, are on demand tariffs. JGN proposed to restructure its demand tariffs to:

- recover trunk costs in a way that:
  - is consistent with the STTM hub arrangements and market definition
  - reflects the legal classification of the trunk pipeline as a distribution network
  - makes JGN indifferent to future sources of gas and transmission connection points
- avoid the situation where JGN's network prices drives separation in the wholesale gas price between coastal regions of Sydney, Wollongong, Central Coast and Newcastle

- remove perverse incentives at the volume/demand customer threshold by smoothing the pricing transition between these customer segments by introducing a minimum demand bill

- incentivise more effective load shedding responses using a tariff discount.

12.2 Summary of AER draft decision

The AER draft decision considered that[337]:

- *Volume and demand tariffs* – JGN's AA proposal for haulage reference services complies with the NGR, but based on amendments to total revenue, demand, changes to the minimum bill and first response tariffs set out in chapters 10, 11 and 12 of the draft decision, the volume and demand tariffs would need to be amended in order to make the proposal acceptable to the AER.

- *First response tariffs* – JGN's AA proposal does not comply with the NGR because JGN had not sufficiently demonstrated the required discount or the assumed level of customer take-up. The AER did not accept JGN's first response forecast and considered that at most 50 per cent of eligible customers would take up the tariff and the other 50 per cent would remain on the default coastal capacity tariffs.

- *Minimum bill tariffs* – JGN's AA proposal does not comply with the NGR because it may dissuade increases in usage at the threshold between volume and demand customer categories.

- *Legacy services and ancillary services* – JGN's AA proposal does not comply with the NGR because the AER considered these contracts and ancillary activities would be sought by a significant part of the market and should therefore be reference services in the next AA period with a reference tariff.

Table 12-1 sets out the amendments that the AER stated in the draft decision would be required in order to make the proposal acceptable to the AER in relation to reference tariffs.

337 Draft decision, p. 279.

Table 12-1: Amendments the AER required in its draft decision –reference tariffs

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
12.2	Amend the AAI by: Deleting the bullet point about perverse incentives from section 14.1 Delete the three paragraphs under the heading titled "Minimum demand bill" included in section 14.3.4 NB: Amendment 13.1 included a requirement for the deletion of clause 1.2 F(i) of Schedule 2.	Partially incorporated. While JGN has not incorporated the deletion of clause 1.2F(i) of Schedule 2 of the AA. However the AAI has been condensed such that this amendment is no longer relevant	Section 1.3.4
12.3	Amend: the AAI (pricing model) to halve the demand forecasts for demand first response tariff classes that contain more than one customer. The quantities that are removed from the first response are to be allocated to appropriate demand coastal tariff classes the AA proposal to reduce the demand first response discount to 25 per cent clause 1.2F (d) of schedule 2 the AAI to reduce the demand first response discount to 25 per cent in section 14.3.4 the additional revenue recovered by JGN as a consequence of the amendments in this amendment 12.3, must only be used to reduce tariffs for all coastal demand customers on an equal percentage basis.	Incorporated with modification	Section 12.3.5

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
12.4	Amend: The AA proposal to remove the premium associated with the legacy services in section 2.4 The AAI to remove the premium associated with the legacy services in section 13.3.2 The AAI to remove the premium associated with the legacy services in Schedule 2 – Initial Reference Schedule	As JGN has removed legacy contract concept from the AA this amendment is no longer relevant	Not relevant
12.5	Amend the AA proposal to delete the words "Reference Tariff Policy" in the heading of section 3 and replace them with "Reference Tariffs and Reference Tariff Variation Mechanism". Make any and all subsequent amendments necessary to reflect this change.	Incorporated	Not relevant
12.6	Amend the AA proposal to delete section 1.5(b) of Schedule 3 and replace it with the following: "If there is any inconsistency between section 3 of the AA and the Reference Tariff Schedule, unless otherwise provided, section 3 of the AA takes precedence"	Not incorporated	Not relevant

12.3 JGN response to AER draft decision

12.3.1 Principles of tariff reform and STTM

The Ministerial Council on Energy (**MCE**) has initiated the STTM which is a major market reform in the NSW gas supply system. This reform establishes a wholesale gas market in the coastal NSW area and aims to deliver efficient wholesale gas prices and thereby support more efficient gas production and transmission connection investment signals which will ultimately improve the security of supply for NSW customers.

In a nutshell, the reform provides a significant advancement towards the NGO in elements of the supply chain that are not directly associated with the provision of network services.

The reforms affect certain aspects of JGN's network services and JGN has sought to accommodate these in a manner that best facilitates the reforms achieving their intent.

One of the key ways that JGN has sought to accommodate the movement towards the STTM is to establish charges that reflect the new hub nature of the NSW coastal network, and which do not discriminate between different sources of gas into that network. This can be expected to best support the efficient expansion of wholesale gas supply to the STTM.

JGN does not benefit from the changes to its charging structure set out above. Under the NGR, JGN will receive the same total allowed revenues regardless of its charging structures.[338]

End use customers impacted by changes to network charging structure will accrue benefits arising to all parties that purchase gas traded in the STTM. These benefits are expected to arise through increased wholesale market competition leading to lower prices for gas delivered to STTM hubs. JGN welcomes the AER's draft decision to approve this STTM facilitating network tariff restructure, which facilitates the STTM and affects a small percentage of JGN's customers.

12.3.2 Volume tariff classes

JGN has retained the two volume tariff classes proposed in its original AA proposal: coastal and country.

JGN has updated its proposed tariffs for volume customers to reflect the revised cost of service, demand forecasts and resulting price path set out in this submission. The resulting prices are detailed in schedule 2 of JGN's revised AA.

12.3.3 Demand tariff classes

JGN has retained the 24 demand tariff classes proposed in its August 2009 submission. These comprise 23 location-based demand capacity and demand capacity first response tariff classes, and a non-locational throughput tariff.

In addition, in its revised proposal JGN has included 10 new tariff classes as a result of two new demand tariff categories DMT (major end-customer throughput) and DMTFR (the corresponding first response category) for the five Sydney tariff locations. The DMT and DMTFR tariffs offer users an opportunity to cap the DC and DCFR charges payable for large Sydney customers.

The DMT tariff recognises that the combined effects of the underlying cost of service increases reflected in the P_0 and the restructure to accommodate the STTM in Sydney is significant. JGN observes from some stakeholders'

338 NGR rule 92(2).

submissions a concern about some large users' ability to respond to these new price signals in the timeframe envisaged in JGN's original AA proposal. Having regard to the fact that certain large users may have made significant capital investments and cannot rapidly adjust their usage to the new pricing arrangements, notwithstanding the anticipated gas price savings of the STTM, JGN has sought to cap the price transition for these large users. At the same time, JGN has included the DMTFR tariffs to maintain an incentive for large Sydney customers to participate in JGN's first response enhancements to curtailment effectiveness.

When adding these two new tariffs JGN has had regard to 'whether customers belonging to the relevant tariff class are able or likely to respond to price signals' in accordance with rule 94(4)(b)(ii). JGN has updated its proposed tariffs for demand customers to reflect the new proposed tariffs, the revised cost of service, demand forecasts and resulting price path set out in this submission. The resulting prices are detailed in Schedule 2 of JGN's revised AA revision.

12.3.4 Minimum bill within demand tariff class

JGN has retained its proposed minimum bill for demand customers with the same transitional provisions set out in its original AA proposal submission. This tariff feature is essential to remove perverse incentives that currently exist at the threshold between volume customers and demand customers.

The present situation cannot be considered consistent with the NGO and it is critical that the amendments JGN has proposed in this regard are approved.

JGN's proposed minimum bill charge applies to demand customers that transition from the volume to the demand customer classes and who in doing so would otherwise experience a price decrease due to the regional cost allocation constraint previously imposed on JGN's demand tariffs. This sought to address a perverse incentive effect that arises under the current AA at the threshold between these two customer classes.

In making this proposal, JGN acknowledges that there may be a short-term pricing adjustment for some customers that they potentially could not respond to immediately. To address this, JGN proposes a transitional introduction of the minimum bill for existing customers as set out in Table 12-2.

Table 12-2: Monthly minimum bill transition path

	2010-11	2011-12	2012-13	2013-14	2014-15
Target minimum bill to achieve efficient use incentive ($, 2010 real)	5,000	5,000	5,000	5,000	5,000
Minimum bill charge ($, 2010 real)	1667	2500	3333	4167	5000

	2010-11	2011-12	2012-13	2013-14	2014-15
Share of target	33%	50%	67%	83%	100%

This path provides a five year adjustment window for users and customers to take the efficient pricing signal into account in their budgeting and usage decisions.

The AER's draft decision rejected this part of JGN's tariff proposal. The AER stated that:

> the proposed solution to address the inefficient use of gas by volume customers may have the reverse effect for large volume users. In effect the minimum bill may result in some large volume users seeking to constrain consumption to avoid the minimum bill charge contra to the objective to promote the efficient use of gas. The large volume users may avoid their gas consumption increasing above 10 TJ a year in order to avoid being reclassified as a small demand user which is charged at capacity rate.[339]
>
> and
>
> The AER considers that a volume customer receives a very different service to a demand customer. Since demand customers are offered a more constrained service, it should be the case that the distribution charges for a given quantity of gas should be lower for a demand customer in comparison to a volume customer.[340]

JGN considers that both the AER's points reflect a misunderstanding of JGN's proposal and the facts relevant to its consideration. They also constitute an overly simplified representation of the principles underlying efficient network tariff setting.

JGN's proposed minimum bill will smooth the transition to the demand customer charges. It does not involve a price increase relative to the top end of volume customer charges. In fact, the transition path proposed by JGN means many customers at this threshold will still receive a price reduction if they pass this threshold in the first four years of the AA period. Even once the transition path finishes in 2014-15, customers will still face a flat rather than increased charge.

This means the AER's statement that 'the minimum bill may result in some large volume users seeking to constrain consumption to avoid the minimum bill charge' is incorrect.

The correct assessment of customers near to, on or just over the 10 TJ threshold set out in JGN's proposed minimum bill is that for all these instances JGN's proposal is the only way to support efficient consumption signals. The smoothed (as opposed to increased or decreased) transition path is the only way this can be achieved.

339 Draft decision, p. 274.

340 Draft decision, p. 273.

Table 12-3 sets out worked examples of these three scenarios that prove this point, both during the transition period and once the transition is complete.

Table 12-3: Minimum bill threshold scenario analysis - $/month

Tariff	No minimum charge			Transition (2011)			Post transition		
	9.5TJ	**10TJ**	**12TJ**	**9.5TJ**	**10TJ**	**12TJ**	**9.5TJ**	**10TJ**	**12TJ**
DC-1	$4,891	$1,386	$1,561	$4,891	$1,847	$1,847	$4,891	$5,180	$5,180
DC-2	$4,891	$1,477	$1,672	$4,891	$1,847	$1,847	$4,891	$5,180	$5,180
DC-3	$4,891	$1,799	$2,064	$4,891	$1,847	$2,064	$4,891	$5,180	$5,180
DC-4	$4,891	$2,601	$3,037	$4,891	$2,601	$3,037	$4,891	$5,180	$5,180
DC-5(DT)	$4,891	$4,741	$5,576	$4,891	$4,741	$5,576	$4,891	$5,180	$5,576
DC-6	$4,891	$981	$1,070	$4,891	$1,847	$1,847	$4,891	$5,180	$5,180
DC-7	$4,891	$1,928	$2,220	$4,891	$1,928	$2,220	$4,891	$5,180	$5,180
DC-8	$4,891	$3,377	$3,980	$4,891	$3,377	$3,980	$4,891	$5,180	$5,180
DC-9	$4,891	$757	$798	$4,891	$1,847	$1,847	$4,891	$5,180	$5,180
DC-10	$4,891	$1,214	$1,353	$4,891	$1,847	$1,847	$4,891	$5,180	$5,180
DC-11(DT)	$4,891	$4,741	$5,576	$4,891	$4,741	$5,576	$4,891	$5,180	$5,576
DC-Country	$4,686	$987	$1,077	$4,686	$1,847	$1,847	$4,686	$5,180	$5,180
DT	$4,891	$4,741	$5,576	$4,891	$4,741	$5,576	$4,891	$5,180	$5,576

Notes:

- DC-5 and DC-11 tariffs are greater than DT tariff. Assignment to DT has been assumed.
- Load factor 65 % and 2 km assumed for DC-Country.
- Charges include Reference Haulage Service and Meter Data Service.
- 9.5TJ columns contain V-Coastal or V-Country Tariff as appropriate.

The AER statement that demand customers who pay capacity charges receive a more constrained service and should pay less for this is an oversimplification of network pricing principles.

JGN is obliged under the NGR to have regard to the relative costs that different categories of users impose on the network.[341] Hypothetically, JGN could charge a specific tariff for every customer of the network. However the transaction costs of doing so will likely outweigh the benefit as contemplated by rule 94(2)(b).

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[341] NGR, rule 94 (2) and (4)

In practice, once a customer hits a certain threshold level of consumption, their cost impost on the network changes in a manner that warrants a charging differential. JGN has traditionally grouped customers into two classes at the 10 TJ consumption threshold. JGN has implemented this differentiation based on both capacity—i.e. the 'demand' part of the tariff class—and location.

In contrast to the volume customer tariffs, the location part of demand customer tariffs is an important factor. Whereas volume tariffs are averaged across the NSW network, demand customers pay a charge that reflects their position within that network.

JGN's minimum bill seeks to manage the transition between these two very different billing bases. Asserting that a customer should pay less when they move from a volume to a capacity charge ignores this important location cost reflectivity feature of JGN's tariff structure.

12.3.5 Demand first response tariff

Context and consequences of load shedding

JGN's experience from the load shedding events that have occurred in the past 5 years is that the rate of response from the entire demand market to load shedding requests must be improved. If load shedding does not operate effectively then the consequences may be the uncontrolled supply failure within the network, which may involve hundreds of thousands of customers and may take weeks or months for supply to be re-established.

An effective first response tariff is necessary to provide an incentive for the few largest customers to establish the operational procedures necessary to interact with JGN during emergencies that threaten the safety and integrity of supply in the network so that a meaningful level of immediate demand reductions can be reliably achieved.

Notwithstanding the new first response tariff, current obligations on all demand customers to participate in load shedding will still apply, and all demand customers will still be required to reduce demand in accordance with the load shedding priorities relevant to an event. First response reductions are not intended to prevent or substitute for other demand customers from being called to load shed. After first response has been initiated, the load shedding process will continue to work down through other demand and volume customers until the required total demand reduction has been achieved for safety and integrity of the network.

Customer survey

In the light of the clear need for a first response tariff JGN conducted a survey of end customers with hourly utilisation of around 100 GJ per hour or more, to test their reaction and level of interest in the first response tariff. The results of the survey demonstrate that both JGN's revised demand assumptions and required discount for its demand first response tariff are appropriate.

Results of the survey are set out in Table 12-4.

Table 12-4: Customer survey results

	Very large customers (> 350 GJ/hr)	Other major customers (100-350 GJ/hr)
Invited to participate:	9	10
Written responses	7	2
Did not respond	2	8
Is your plant physically able to reduce by 40 per cent in 6 hours?		
Yes	5	0
No	2	2
Would your plant participate in the demand first response tariff at a 25 per cent discount?		
Yes	1	0
No	5	2
Would your plant participate in the demand first response tariff at a 50 per cent discount?		
Yes	6	0
No	0	2
Do you wish to work with JGN to establish curtailment plan etc. to qualify for demand first response tariff?		
Yes	7	0
No	0	2

Notes on survey for >350GJ/hr customers:
One customer that responded did not comment on discount levels.
The two customers that did not respond have indicated that they will consider the tariff.

The survey shows a strong interest from the larger major customers in participating in the tariff with a 50 per cent discount, however virtually no interest at the reduced level of 25 per cent. 100 per cent of the very large customers responding to the survey have registered with JGN to work towards developing the ability to qualify for the tariff.

End customers with hourly demand in the range of 100 to 350 GJ per hour either did not respond or responded that they were not interested in participating in the tariff.

JGN's revised proposal for its demand first response tariff

Based on the above survey results, JGN has revised its proposal for the first response tariff as follows:

- *discount* – JGN has retained its proposal for a 50 per cent discount
- *eligibility threshold* – JGN has changed the assignment criteria for the proposed discounted tariff from sites greater than 100 GJ per hour to greater than 350 GJ hour
- *forecast take-up* – JGN has reduced its original forecast for the take-up of its demand first response tariff to be the consumption of customers greater than 350 GJ per hour.

In its draft decision, the AER stated that:

> Jemena is required to support its revised proposal with information detailing the basis for the discount and the proportion of customers that are proposing to take-up the demand first response tariff (as substantiated by user negotiation).[342]

Below JGN expands upon the basis for:

- its demand first response tariff discount
- its forecast of the proportion of customers that will take-up the demand first response tariff.

The demand first response tariff discount

The survey responses from the larger customers were clear that the level of tariff participation likely to result from a 25 per cent discount would not provide the desired operational benefit to JGN, and that a 50 per cent discount is required to secure a level of take up that provides the operational benefits of load shedding.

The survey confirmed JGN's previously expressed view that the discount must be significant in order to motivate first response emergency curtailment because network charges are only a small part of delivered gas prices and curtailment costs can be significant. In its additional information to the AER,[343] JGN explained that for the larger end customers, network charges are estimated to represent only a

[342] Draft decision, p. 273.

[343] JGN, *Response to AER 17 December 2009 Questions*, 8 January 2010.

minor proportion of their delivered gas cost - around 5 to 10 per cent. At a 50 per cent discount, the financial incentive for customers to participate in the first response tariff would be around a 2.5 to 5 per cent reduction in their total gas costs.

An obligation to have a curtailment plan in place for the site is likely to be significant. As well as the initial establishment of the curtailment plan, ongoing training and integration of the plan into plant operations to maintain readiness to participate as a first response site will require a significant continuing commitment by plant management. If the level of saving is trivial in comparison to the competing normal workday demands and other opportunities for the plant to make operational savings then there will be inadequate financial incentive for plant staff to invest the time to meet and maintain the tariff assignment criteria.

In the survey, 7 of the 8 very large customer respondents have indicated that they wish to work with JGN and their retailer between now and commencement of JGN's revised AA to establish a curtailment plan and matters relevant to the other assignment criteria for the plant so that the delivery point is able to qualify for a discounted tariff from the start of the AA.

Demand for first response tariff

JGN has reduced its original forecast for the take-up of its demand first response tariff to be the consumption of customers greater than 350 GJ per hour.

Along with its survey results, JGN's changes to its eligibility criteria for the demand first response tariff make it more straightforward to forecast accurately the level of demand that will be subject to the tariff. An accurate forecast is important to JGN and to users and customers because:

- if the forecast is higher than the actual, JGN will receive less than its forecast revenue for the related default demand capacity tariff, and this will impede its ability to recover its efficient costs

- if the forecast is lower than the actual, JGN will recover more than its forecast revenue from customers on the related default demand capacity tariff.

JGN has changed the eligibility criteria for the proposed discounted tariff from sites greater than 100 GJ per hour to greater than 350 GJ per hour. This change recognises that the operational benefits to the network of the first response tariff depend on involving the largest customers and the administrative cost savings of targeting the tariff towards those customers most likely to take it up. It also enables JGN and AER to exclude customers who consume less than 350 GJ per hour from the take-up group whose demand needs to be forecast.

JGN has applied the additional revenue recovered as a result of the above amendments to reduce the tariffs of all coastal demand customers on an equal percentage basis.

12.3.6 Prudent discounts

JGN has retained the prudent discount arrangements set out in its original proposal, to which the AER has provided its approval in the draft decision.

12.3.7 Pricing rule compliance

JGN has updated its long run marginal cost, stand alone cost and avoidable cost estimates to incorporate the inclusion of ancillary activities into the references services. Appendices 12.2 and 12.3 set out JGN's revised proposal using the same methodology detailed in JGN's original AA proposal.

13 Tariff variation mechanism

- JGN proposes a tariff basket tariff variation mechanism that is structurally the same as tariff basket controls that have been adopted and proven in Victoria, South Australia and NSW and provides an efficient means of passing through cost variations.
- The AER's draft decision requires a number of amendments that would change the structure of the proposed mechanism significantly. JGN has incorporated only some of those amendments.

13.1 Summary of JGN original proposal

In its original AA proposal JGN proposed adopting a tariff basket form of price control with a pass through mechanism for its haulage reference service which provides 90 per cent of JGN's regulated revenues. JGN currently earns its revenue through a schedule of prices that it varies annually for inflation and UAG. Unlike a fixed tariff schedule, a tariff basket control sets formulae that govern how JGN may vary tariffs.

JGN proposed retaining a fixed tariff schedule approach for its meter data reference service that does not relate to haulage. This reference service accounts for only 1.3 per cent of JGN's revenues as at 2010-11 and does not warrant a more complex form of annual tariff variation.

The tariff basket variation mechanism (**TVM**) proposed by JGN provided for tariffs to be adjusted for:

- an X factor set originally at -1.96 per cent to give effect to the price path set out in section 13.8 of JGN's original AAI and aligns the NPV of JGN's cost of service with its forecast revenues
- inflation (CPI)
- an annual variation factor which includes a UAG adjustment, weather variation adjustment and licence fee adjustment as well as pass through events.

13.2 Summary of AER draft decision

The AER draft decision approved JGN's move to a tariff basket form of price control. However, the draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal so that the tariff basket variation mechanism includes only X factor and CPI changes, with the annual variation factor not being approved by the AER.

Other changes to tariffs are the result of the pass through tariff variation mechanism.

The draft decision also included a requirement that JGN add a 10 per cent side constraint on annual tariff rebalancing and remove JGN's ability to introduce new tariffs or tariff categories during the AA period without reopening the AA.

Table 13-1 sets out the amendments that the AER stated in its draft decision would be required to make the TVM aspects of the proposal acceptable to the AER.

Table 13-1: Amendments the AER required in its draft decision – TVM

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
12.1	Amend the AA proposal to remove references to the introduction or withdrawal of haulage reference tariffs: delete clause 3.6 (including 3.6H and 3.6I) delete clauses 3.2(b), 3.2(d), 3.2(e) and 3.2(f) delete clause 3.4(c)(iii) delete clause 3.2(g) and replace it with the text provided at p279 o the draft decision delete clauses 3.3(d), 3.3(e), 3.3(f), 3.3(g)(ii) and 3.3(i) delete clause 3.4(a) and replace it with the text provided at p280 of the draft decision delete clause 1.1B(d) of schedule 2 – Initial Reference Tariff Schedule make all consequential amendments to the AA proposal and AAI to reflect the above	Not incorporated	Section 13.3.2

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
13.1	Delete clause (b) of schedule 2 – Initial Reference Tariff Schedule and replace with the following: The Initial Reference Tariffs are expressed in real 2010/2011 dollars. Delete clause (e) of schedule 2 – Initial Reference Tariff Schedule and replace it with the text provided at p303 of the draft decision. Delete the tables in clause 1.2F(a) (b), (c), (e), (f), (g) and (h) of schedule 2 – Initial Reference Tariff Schedule and replace with the tables provided on pages 304-307 of the draft decision. These tables replace the initial reference tariff schedule. Delete clause 1.2F(i) of schedule 2 – Initial Reference Tariff Schedule Delete the tables in clause 1.2G(a) and (b) of schedule 2 – Initial Reference Tariff Schedule and replace with the tables provided at p308 of the draft decision. Delete clause 1.2H of schedule 2 – Initial Reference Tariff Schedule and replace with the tables provided at pp308-310. This amendment is to include ancillary service tariffs in the Reference Tariff Schedule.	Incorporated with modification	Section 13.3.3

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
13.2	Amend the AA proposal to delete section 3.5A and replace it with the provided text at pp310-11 of the draft decision which include a 10 per cent side constraint on annual tariff rebalancing. Amend section 15.4.1 of the AAI to delete the annual variation factor from the second formula and the final two paragraphs about the variation factor. Delete the annual tariff variation events from table 16-1 in the AAI and update the list of pass through events to take into account the AER's draft decision on pass throughs in the draft decision. Amend section 16.1 of the AAI to delete the last paragraph. Amend the AAI to delete section 16.4 and replace with the text on pass through criteria provided at p312 of the draft decision. Delete section 16.5 of the AAI (annual tariff variation factors).	Incorporated in part	Section 0
13.3	Delete section 3.5C (Tariff adjustments and pass through events) and replace it with the provided text at pp312-313 of the draft decision. Delete section 3.5D (Calculation of the UAG Adjustment) and replace it with the provided text at pp314-315 of the draft decision. Delete section 3.5E Calculation of the Weather Variation Adjustment. Delete section 3.5F Calculation of the pass through adjustment for a Licence Fee Event. Delete section 3.5G Calculation of the Other Events adjustment.	Incorporated in part	Section 13.3.5
13.4	Amend section 3.4(b) (Submission to the AER) in the AA proposal to include a rounding convention.	Incorporated	Section 13.3.6

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
13.5	Amend section 3.4(b) in the AA proposal to include a new paragraph (vi) stating: If it appears that any past tariff variation contains a material error or deficiency because of a clerical mistake, accidental slip or omission, miscalculation or misdescription, the AER may change subsequent tariffs to account for these past issues.	Not incorporated	Section 13.3.7
13.6	Amend the AA proposal to delete sections 3.4(b)(i) and (ii) Submission to the AER and replace with the text provided at p315 of the draft decision. Amend the AA proposal to delete section3.4(b)(iii) Amend the AA proposal to delete sections 3.4(b)(iv), (d)(i), (d)(ii) and (d)(v) and replace with the text provided at pp315-316 of the draft decision. Amend the AA proposal to delete section 3.4(e) Amend the AAI to delete the first sentence of section 15.4.2 (Tariff variation process) and replace it with the text provided at p316 of the draft decision.	Incorporated in part	Section 13.3.8
13.7	Amend AA to delete section 3.5B Calculation of CPI adjustments and replace with text provided at pp316-317 of draft decision to require JGN to use December quarter CPI for its annual tariff variations.	Incorporated	Section 13.3.9
13.8	Amend the AA proposal to include a new paragraph (iv) in section 3.4(c) to provide for a verified statement of past actual gas quantities used to determine tariffs each year of the AA period.	Incorporated	Section 13.3.10

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
13.9	Amend the AA proposal to delete section 3.4(c)(ii) and replace with the text provided at p317 of the draft decision to add requirement that JGN provide its workings, demonstrating how the proposed tariffs have been calculated in accordance with the tariff variation mechanism.	Incorporated	Section 13.3.11
13.10	Amend the AAI so the cost pass through events described at section 16.6 are described and named according to the cost pass through categories set out in section 3.5C(c) of the AA proposal.	Incorporated with modification	Section 13.3.12
13.11	Amend the AA proposal to include a new paragraph (vii) in section 3.4(d) provided at p317 of draft decision with criteria to be applied by AER when considering whether to approve a pass through event.	Incorporated with modification	Section 13.3.13
13.12	Amend the AA proposal to include a new paragraph (viii) in section 3.4(d) provided at pp317-318 of draft decision with requirement to provide the AER with: a statement verifying that the costs of any pass through events are net of any payments made by an insurer or third party which partially or wholly offsets the financial impact of that event (including self-insurance) information from the relevant taxation or regulatory authority in support of any application for a Change in Tax Event a statement verified by an auditor in support of any application for UAG Adjustment Event	Incorporated in part	Section 13.3.14
13.13	Amend the AA proposal to include a new paragraph (ix) in section 3.4(d) provided at p318 of draft decision: Tariffs will only change once a year on 1 July as a result of Change in Tax events and UAG Adjustment Events.	Incorporated with modification	Section 13.3.15

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
13.14	Amend the AA proposal to include a new paragraph (x) in section 3.4(d) provided at p318 of draft decision to require JGN to notify AER within 90 days of costs being incurred from a cost pass through event.	Incorporated with modification	Section 13.3.16

13.3 JGN response to AER draft decision

13.3.1 JGN's tariff variation mechanism

Rule 97(2) offers (by way of example) a number of alternative TVMs. JGN has adopted the tariff basket price control option[344].

Tariff basket price controls are well established for both electricity and gas in a number of jurisdictions. In particular, those tariff basket price controls provide for adjustments to be made for a variety of factors other than CPI and X. JGN has taken the general form of those controls and adapted it to its circumstances by including adjustments for weather variations, UAG cost variations and licence fee variations as part of normal annual tariff variations.

The TVM that JGN has proposed also provides for the introduction and removal of haulage reference tariffs.

13.3.2 Introduction and removal of reference tariffs – amendment 12.1

The AER requires JGN to remove provisions of its proposed TVM that deal with the introduction and removal of tariffs on the basis that "the relevant process to consider changes to reference tariffs is through an access arrangement revision process, this may be scheduled as outlined in chapter 14 or unscheduled."[345]

JGN has not incorporated these amendments.

JGN agrees that the access arrangement revision process is one option for considering changes to reference tariffs. However, that option would be costly and add to uncertainty. Logically, opening the AA should be reserved for consideration of changes that affect all reference tariffs.

Gas is a competitive fuel and it is important that JGN should be able to respond quickly to changes in the market and external factors such as changes in energy

344 NGR, s97(2)(b)

345 Draft decision, p. 278.

efficiency policy, carbon emissions policy, and emerging technologies. For example, JGN may seek to introduce tariffs for cogeneration proponents, or natural gas vehicles. Similarly, the ability to close and grandfather tariffs is a necessary tool to avoid duplication and confusion as tariff offerings evolve.

The tariff basket price control structure is particularly well suited to the introduction and removal of tariffs and there is regulatory precedent for such arrangements:

- The current tariff basket controls for electricity and gas distribution in Victoria, as approved by the ESC, both provide for the introduction and removal of tariffs. [346]

- The tariff basket control approved by ESCOSA for Envestra's gas network in South Australia provides for the introduction or withdrawal of tariffs and tariff components. [347]

- The tariff basket controls approved by the AER for the electricity distribution businesses of Energy Australia, Country Energy, Integral Energy provide for the introduction of new tariffs and tariff components. [348]

The AER has not provided any reasons why changes to reference tariffs (including the introduction and withdrawal of tariffs) should not be made through the TVM in the case of JGN.

Providing for the introduction and removal of tariffs by way of the TVM, as proposed by JGN, is consistent with maintaining the efficiency of tariff structures (Rule 97(3)(a)); is administratively less costly than re-opening the access arrangement (Rule 97(3)(b)); and is consistent with pre-existing arrangements in other jurisdictions (Rule 97(3)(c)).

[346] See:

ESC, *Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination*, October 2005, section 2.4.2, p. 25.

Multinet Gas, *Access Arrangement, Part B – Reference Tariffs and Reference Tariff Policy*, 2 June 2008, section 3, p. 6.

[347] ESCOSA, *Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System, Final Decision,* June 2006, p. 182.

[348] AER, *New South Wales distribution determination 2009-10 to 2013-14, Final Decision*, 28 April 2009, Appendix J, p. 464.

13.3.3 Initial Reference Tariff Schedule – amendment 13.1

JGN has incorporated the following changes to Schedule 2 – Initial Reference Tariff Schedule, in response to amendment 13.1:

- All reference tariffs are now expressed in 2010-11 dollars. The changes to clauses (b) and (e) of schedule 2 have been incorporated. Headings of all tables containing reference tariffs in schedule 2 now refer to 2010-11 dollars.

- All amounts in the Initial Reference Tariff Schedule have been recalculated to recover forecast revenues that are consistent with the positions that JGN has taken in relation to other amendments.

- Ancillary fees are now expressed as charge components of the reference tariffs for the Reference Haulage Service and Meter Data Service. Accordingly, those fees will now be subject to variation in accordance with the TVM.

As stated in item 8 of JGN's letter to the AER dated 3 March, 2010, JGN has continued to include a minimum chargeable quantity for the DT tariff class throughput charge and minimum charges for Provision of Basic Metering Equipment Charges for volume tariff classes where meter capacity is greater than $6m^3/hr$. These minimum charges and chargeable quantities are consistent with current terms and conditions.

JGN has not incorporated the requirement from amendment 13.1 that JGN delete clause 1.2F(i) of schedule 2 (Minimum Aggregate Charge). JGN's reasons for maintaining the Minimum Aggregate Charge are given in section 12.3.4.

JGN has also made the following additional changes to the Reference Tariff Schedule:

- Two typographical omissions in JGN's original AA proposal have been corrected. The DT demand tariff class was inadvertently omitted from the table in clause 1.2F(f)[349] and postcode 2148 was inadvertently omitted from location identifier 2 in the table in clause 1.2C[350].

- Clauses 1.1 B, 1.1 E and 1.2 F have been amended to include two new demand tariff categories (DMT and DMTFR) each with five new tariff classes. This is explained in section 12.3.3 of this response.

349 This omission was inconsistent with the forecast revenues in the pricing model and also the table in clause 1.2E(C) which specifies that a Provision of Basic Metering Charge is payable for the DT tariff class.

350 Postcode 2148 is in local network zone Sydney 2 which is the same grouping as location 2 in the proposed AA.

13.3.4 Amendments to the TVM constraints including not approving JGN's proposal to include automatic adjustments to compensate for weather variations from year to year, UAG cost variances and licence fee variations – amendment 13.2

Following its review of the draft decision, JGN has incorporated AER amendment 13.2 in part:

- *Removing the V_t term* – JGN does not consider that it should amend the tariff basket TVM formula by removing the V_t term so that the formula adjusts for CPI and X only. By requiring this amendment, the AER has denied JGN automatic tariff adjustments to compensate for variations in weather from year to year, UAG cost variances, licence fee variations, and other events.

- *Weather adjustment factor* – JGN maintains that adjustments to compensate for variation in weather from year to year, UAG cost variances and licence fee variations should occur automatically through the TVM and that other events, as approved, should also be corrected for through the TVM. JGN maintains that the inclusion of these automatic adjustments in its AA is consistent with the requirements of the NGR and, as such JGN does not agree with the AER's reasons relating to the removal of these automatic adjustments.

- *Side constraints* – JGN accepts, in principle, the amendment requiring that variations of individual tariff classes be subject to a side-constraint. JGN has incorporated such a mechanism, but not in the exact form specified by the AER because the form required by the AER does not include the V_t term. JGN has also described the side constraint in a new paragraph in section 3.1 of the proposed AA.

- *General pass through event* – JGN will add General Pass Through Event to the list of risk events in Table 16-1.

Accordingly, JGN has amended the description of the component terms of the TVM formula as required by amendment 13.2 except that it has not removed the second paragraph under the definition of the term q_{t-2}^{xy}, viz:

> for the Financial Year $t-2$ which is the Financial Year ending 30 June 2010, is the quantity of component y of Reference Tariff x forecast by the Service Provider for Financial Year ending 30 June 2011 for the purpose of determining the values of X_t as submitted to the AER;

That provision is required so that the quantities to be used in applying the TVM formula for the 2011-12 year are defined. Without that provision they would undefined.

The form of the TVM constraint

In the draft decision, the AER considers that the TVM should not include automatic compensation for variations in weather from year to year (the W factor[351]), UAG cost variances (the U factor[352]), licence fee variations (the L factor[353]) or variations for other events (the O factor[354]). The AER justifies its position in part on the basis that "tariff variation mechanisms in other access arrangements…generally only reflect CPI adjustments".[355] Even if that statement was correct, it is not a valid reason not to approve JGN's proposal. The NGR specifically contemplates the tariff basket approach for tariff variation[356] and does not impose any general limitations as to form. In any event, innovation should be encouraged rather than discouraged.

There is relevant precedent for the form of tariff basket proposed by JGN. The AER, ESC and IPART have all approved tariff baskets with parameters additional to CPI and X.

ESC has routinely approved tariff basket TVMs for both gas and electricity distribution in Victoria that include one and sometimes two adjustment terms besides CPI and X. [357] It is also notable that the ESC allows automatic recovery of licence fee variations in the TVM for both electricity and gas (equivalent to the L factor in JGN's proposal (AA section 3.5F)). While the mechanisms approved by the ESC may involve adjustments for fewer and different factors than JGN proposes, the principles are the same.

Similarly, IPART approved a "weighted average price cap" control formula for electricity distribution businesses in NSW for the period 2004-09. The tariff basket constraint in that case included a demand management cost recovery factor (D factor) in addition to CPI and X adjustments.[358] It is notable that the AER "[has decided] to apply the D–factor scheme to the NSW DNSPs over the [2010-14]

351 AA proposal, section 3.5E

352 AA proposal, section 3.5D

353 AA proposal, section 3.5F

354 Original AA proposal, section 3.5G

355 Draft decision, p. 291.

356 NGR, s97(2)(b).

357 See for example:

Multinet Gas, *Access Arrangement Part B Reference Tariffs and Reference Tariff Policy*, Part B: Appendix 2, Formula 6, 2 June 2008 and

ESC, *Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination,* October 2005, p.12.

358 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09*, Final Report, June 2004, p. 16.

regulatory control period, in the form applied by IPART over the [2005-09] regulatory control period."[359]

JGN's proposed TVM is modelled on, and is a logical extension of, the approach that has been adopted and proven in Victoria, South Australia and NSW.

Efficiency of tariffs

In dismissing both the W factor and the U factor the AER refers to the possibility that the efficiency of tariffs will be compromised if those factors were included in the TVM.[360]

While JGN's proposal as to the allowable cost of UAG differs from current and past practice, the principle of passing on UAG cost variances automatically in the TVM is well established. During the current AA period and the period before that, the adjustment has been made automatically as part of annual tariff adjustments in accordance with Clause 3.11.2 of the current AA and Clause 3.10 of the AA for the preceding AA period.

The overall tariff basket constraint proposed in AA s3.5A determines the maximum amount by which tariffs in aggregate may vary. As proposed, weather variation and UAG cost variances will contribute to the quantum of that maximum through the W and U factors respectively. The efficiency of individual tariffs is a consideration in the process of allocating that total variation amount to individual tariffs and will be governed by any side-constraint(s) around that process. There is no direct connection between the inclusion of the W and U factors in the TVM and the efficiency of individual tariffs.

It is notable that the proposed TVM tariff basket constraint includes an X factor which effectively sits alongside the W and U factors in the proposed TVM just as X sits alongside other factors in the TVMs approved by the ESC and IPART. If the efficiency of tariffs is a relevant consideration in deciding whether the W and U factors should be included in the TVM for JGN then X (which is likely to be far more significant in determining the outcome) should be examined in the same way. Clearly there is no precedent or justification for that.

Compensation for time value of money

The AER proposes not to approve JGN's proposal to adjust variation amounts by the WACC to account for the time value of money.[361] The AER cites Rules 76, 78 and 87 in support of its position but without reasoning. JGN does not accept the AER's position or that the rules cited support that position.

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359 AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, 28 April 2009, p. xliii.

360 Draft decision, pp. 291 and 292.

361 Draft decision, p. 293.

Rule 76 lists the building blocks that go to make up the service provider's total revenue requirement for each year of the access arrangement period. JGN agrees that there is no building block that would describe the WACC uplift proposed as part of JGN's TVM or, for that matter, the sorts of retrospective adjustments that are implicit in the W, U, L and O factors and pass through amounts generally. However, Rule 76 is only relevant to the determination of total revenue requirement before the next AA period. Rule 76, and rules 78 and 87, are irrelevant to the question of what adjustments should be allowed during the AA period and how those adjustments should be quantified. What rules 76 and 87 do teach is that the time value of money results in a cost that the service provider is entitled to recover.

The position taken by the AER here is also inconsistent with one of the reasons upon which the AER does not approve the W factor. In that case the AER argues that the W factor will "invariably impact the relationship between the present value of the expected revenue and total revenue which is required to be equalised through the tariff variation mechanism".[362] As is the case with the W factor itself, the proposed WACC uplift for the W, U, L and O factors and pass through amounts generally preserves rather than distorts present value and is therefore consistent with rule 92(2).

Finally, JGN notes that the ESC allows a WACC adjustment for the factors that are included in the tariff basket TVMs that it has approved for gas and electricity.[363] And the national electricity rules specifically provide for the time value of money to be taken into account:

> [In assessing the amount to be allowed for a cost pass through event] the AER must take into account:
>
> (4) the time cost of money based on the *weighted average cost of capital* for the provider for the relevant *regulatory control period*;[364]

Thus, inclusion of compensation for the time value of money as proposed would improve consistency across Australian jurisdictions and between gas and electricity, which would be consistent with the recommendations of the Ministerial Council on Energy's expert panel.[365]

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362 Draft decision, p. 290.

363 See for example:

Multinet Gas Access Arrangement Part B Reference Tariffs and Reference Tariff Policy, Part B: Appendix 2, Formula 4, 2 June 2008 and

ESC, Electricity Distribution Price Review 2006-10 Final Decision Volume 2 Price Determination, October 2005, pp. 16 and 23.

364 National Electricity Rules, s. 6.6.1(j).

365 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

Costs of administering a TVM that includes automatic adjustments for weather and UAG

In not approving JGN's proposal to include a W factor in the TVM, the AER cites "higher administrative costs for [JGN], users and the AER"[366]. A similar argument is made to support the draft decision to deal with UAG cost variances as a cost pass through event rather than automatically through the TVM.[367]

Firstly it should be noted that including the W and U factors in the TVM does not add to the administrative costs of users and prospective users. Tariff variations will occur irrespective of whether the TVM includes those factors.

Secondly, as noted above, JGN has included automatic adjustments for UAG cost variances in annual tariff variations throughout the current and preceding AA periods, and the ESC allows automatic adjustment for licence fee variations (L factor) in the tariff basket TVMs that it has approved for gas and electricity. The AER currently administers these annual variation arrangements for JGN and Victorian electricity and gas businesses. This means there would be no discernable incremental cost beyond current practice.

The TVM will involve JGN submitting a tariff variation proposal to the AER which the AER will review and approve if it satisfies the constraints and any other criteria established in the AA. Including the W and L factors in the TVM will add incrementally to the cost of that process for both JGN and the AER but not for users or prospective users. The question is how would those incremental costs compare with the cost of JGN preparing and the AER assessing ad hoc pass through applications? In JGN's view, it would be less costly and more efficient to allow for weather variations, UAG cost variances and licence fee cost variances through the TVM as an incremental step in a routine annual process, rather than as cost pass through events involving separate ad hoc processes.

Matters specific to the W factor:

JGN proposes a weather variation factor (W factor) in the following form as part of its tariff basket tariff variation mechanism (TVM):

$$W_t = wf_{t-2}(1+WACC)^2(1+CPI_{t-1})(1+CPI_t)$$

wf_{t-2} is the financial impact of weather variations in the Financial Year *t* – 2 and is calculated as:

[366] Draft decision, p. 291.

[367] Draft decision, p. 292.

$$wf_{t-2} = (HDD_{forecast} - HDD_{actual})(R_{avg})(\alpha)$$ [368]

The W factor is intended to adjust prices to compensate for the effects on demand of heating degree days (HDD) for a year being above or below normal. The AER proposes not to approve the weather adjustment[369].

Submissions criticise the W factor on the grounds that it is complex, that it is not transparent, and that the value of α (17,100 GJ per HDD in JGN's original AA proposal) is not substantiated. [370]

Mathematically the adjustment is very straight forward: it is neither complex nor opaque. The values of $HDD_{forecast}$ and α are set in the AA itself while HDD_{actual} is readily derived from data published by the Bureau of Meteorology. (JGN obtains and analyses the relevant temperature data in the normal course of business.) The R_{avg} term is based on a subset of the data (quantities and tariffs) that is used to determine the overall variation constraint (AA section 3.5A) and to calculate the overall variation factor V_t (AA section 3.5C(e)).

The AER asserts that the "inputs to the [W factor] are not readily discernable and verifiable by third parties including the AER"[371]. We note above that HDD_{actual} is derived from data available from the Bureau of Meteorology. As to the other inputs, NIEIR in their updated report have established a base annual level of HDD of 490 for 2009-10 and identified a declining trend of 5.56 HDD per year[372]. The values of $HDD_{forecast}$ are set out in the AA for each year of the next AA period and have been determined by applying the trend to the base. NIEIR have also determined the value of α (17,000 GJ per HDD)[373]. ACIL Tasman, in assessing NIEIR's earlier report, suggested a 5.5 HHD per year declining trend was supportable[374] and endorsed the annual base level of 489 HDD (in NIEIR's earlier report) and the value of α (17,100 GJ per HDD in NIEIR's earlier report) indirectly by accepting NIEIR's approach to normalisation[375] and the resultant normalised values as the basis for the regression calculations reported in Figure 11 of ACIL Tasman's report.

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368 AA proposal, s3.5E.

369 Draft decision, pp. 290-291 and amendments 13.2 and 13.3.

370 Draft decision, p. 291.

371 Draft decision, p. 291.

372 NIEIR, *Natural gas projections NSW Jemena Gas Networks to 2015*, March 2010, p. 31.

373 NIEIR, *Natural gas projections NSW Jemena Gas Networks to 2015*, March 2010, p. 31.

374 ACIL Tasman, *Review of Demand Forecasts for Jemena Gas Networks NSW For the Access Arrangement period commencing 1 July 2010*, 2 February 2010, p. 22.

375 ACIL Tasman, *Review of Demand Forecasts for Jemena Gas Networks NSW For the Access Arrangement period commencing 1 July 2010*, 2 February 2010, p.10.

The EUAA, and the AER in agreeing with the EUAA, misinterpret the nature and purpose of the adjustment. The weather variations that the W factor compensates for cannot be addressed by "appropriate demand forecasting methodologies".[376]

Load in the volume market is particularly sensitive to weather as evidenced by the 17,000 GJ per HDD α coefficient determined by NIEIR and, over the 58 years to 2008, the average absolute difference in HDD count between years has been 65 with a maximum difference of 162 between 1973 and 1974. When preparing a forecast of the type required for the AA the only reasonable assumption is that HDD for a year will be "normal"—apart from allowing for the observed warming trend of -5.56 HDD per year, it is not possible to predict whether a particular year in the future will be colder or warmer than normal. JGN's forecast has been prepared on that basis.

Differences between actual consumption and forecast consumption for a year can be attributed to one or both of the following causes:

1. Underlying market growth is not as predicted. Many factors can contribute to that variation, for example:

    - economic or market conditions are not as predicted

    - government policy changes and initiatives affect consumption

    - JGN's marketing efforts are more or less successful than anticipated.

    Where these underlying changes occur during an AA period and suggest an ongoing trend, JGN may review and adjust its expenditure particularly on expansions and extensions. In that way it can take advantage of trends that lead to higher than forecast consumption and protect itself (to some extent) from the adverse effects of consumption being below forecast.

    The proposed W factor is not intended to and will not compensate for this type of variation which can be characterised as "forecasting inaccuracies".

2. The number of HDD in a particular year is different from normal.

    The HDD for a year is the sum of HDD for each day of the year. There is no reliable basis for predicting even 1 year in advance (let alone 5) that a particular year will have more or fewer HDD than normal. Moreover, because variations in HDD from year to year are unpredictable (apart from the established trend), JGN cannot and does not modify its plans in response to those variations.

376 Draft decision, p. 290.

> Users consume and pay more and JGN benefits when HDD for a year are above normal and JGN loses and users consume less if HDD are below normal. Of course the overs and unders should balance out over time but not necessarily within the 5 year term of an access arrangement. There can be "runs" of warm and cold years in the short and medium term or there can be single years with very high or low numbers of HDD. It is these sorts of occurrences that the W factor is primarily intended to address.

The W factor as proposed will work symmetrically and while it operates ultimately through tariffs, it is designed to return/recover revenue that is gained / foregone as a result of HDD for a year being above/below normal. Contrary to the AER's suggestion,[377] the present value of revenue will be more closely aligned to expected revenue over the AA period with the W factor operating than without it.

JGN also notes that the ACCC has approved a weather adjustment factor for GasNet [378]. That is, there is regulatory precedent for an adjustment of the type that JGN proposes. The GasNet approach is similar in structure and effect to that proposed by JGN. Relevantly, the starting point for both approaches is to determine the change in volume that is attributable to weather being warmer or colder than normal. For JGN that is α x ($HDD_{forecast}$ – HDD_{actual}) and for GasNet it is TS x (Target EDD – Actual EDD) [379]. GasNet's TVM is fundamentally different from the tariff basket TVM proposed by JGN so the two weather compensation approaches cannot be compared beyond these formulae. In GasNet's case the volume change calculated by the formula flows indirectly into the calculation of a "Volume Adjusted Target Revenue".

13.3.5 Amendments to section 3.5 of the AA – amendment 13.3

- JGN has incorporated amendment 13.3 insofar as it:
  - Changes the method of calculating the UAG Adjustment (the U_t term described in section 3.5D in JGN's proposed TVM) except as noted below
  - Introduces the General Pass Through Event.

377 Draft decision, pp. 290-291.

378 See APA Group, *Revised GasNet Australia Access Arrangement*, 1 January 2008, schedule 4, clause 4.6.

379 In Victoria, Effective Degree Days (EDDs) have been adopted to explain the effect of "weather" on gas demand for a day. The EDD measure includes terms that take account of insolation, wind chill, and an adjustment for season, as well as HDD. The number of EDDs for a year is therefore greater than the number of HDD so, for a particular market, the GJ/EDD coefficient will be smaller than the GJ/HDD coefficient. JGN sees no value in adopting EDD as the measure of "weather" for the proposed W factor. NIEIR and ACIL Tasman both support the use of HDD.

JGN has not incorporated:

- The removal of section 3.5C(b) and the associated removal of the Weather Variation Adjustment and reclassification of the UAG Adjustment Event as a cost pass through event. This issue is discussed further in JGN's response to amendment 13.2 in section 13.3.4.

- The deletion of sections 3.5E, 3.5F and 3.5G. JGN has retained these sections to be consistent with JGN's position that the TVM should provide for automatic recovery of the costs of weather variation, licence fee variations, and that the TVM is the appropriate means by which to adjust for the approved costs of other pass-through events.

- The required change in the definition of UAG purchasing cost.

- The introduction of the materiality threshold, the level of the threshold, and related classification of cost pass through events.

- The change from 1 July 2009 to 1 July 2010 in the datum against which Market Cost Events are to be assessed.

Classification of cost pass through events

For reasons discussed in response to amendment 13.2 in section 13.3.4, JGN remains of the view that UAG Adjustments and Licence Fee Adjustments should (along with Weather Variation Adjustments) be dealt with automatically in annual tariff variations via the TVM. It follows that JGN has not incorporated the AER's view that UAG Adjustment events and Licence Fee Adjustments should be classified and dealt with as cost pass-through events subject to the materiality thresholds specified in amendment 13.3.

As discussed below, JGN now proposes to establish the Carbon Pollution Reduction Scheme (CPRS) Event as a separate class of cost pass-through event in section 3.5C(c) of the AA rather than recover that type of cost as a component of the UAG Adjustment.

Accordingly, JGN has retained sections 3.5C(b) and 3.5C(c) in the AA, moving the Licence Fee Adjustment from 3.5C(c) to 3.5C(b) and, for clarity, moving the definitions of UAG Adjustment, Licence Fee Adjustment and Weather Variation Adjustment from 3.5C(c) to 3.5C(b).

Materiality threshold for cost pass through events

JGN has not incorporated amendment 13.3 to the extent that it requires changes to the materiality criteria for cost pass-though events.

The 1 per cent of revenue threshold (approximately $4-5 million) proposed for cost pass-through events other than Change in Tax events and UAG Adjustment events is unreasonably large and out of proportion to:

- the costs that would be incurred by stakeholders in assessing an application for any such adjustment
- the dollar amounts associated with many of the amendments that the AER requires in the DD.

If it is reasonable to require that the Service Provider's revenue requirement be adjusted by amounts that are very much less than $4-5 million before the event in an AA review, then it must be reasonable to allow variations for amounts of similar magnitude after the event where those variations are beyond the control of the service provider as is the case, by definition, for cost pass through events.

It is inconsistent with the national gas objective and the revenue and pricing principles to restrict recoveries to those events that impose a cost greater than 1 per cent of revenue. Such an approach will not promote efficient investment in, and efficient operation of, natural gas services. Most significantly, such an approach will deny JGN a reasonable opportunity to recover at least the efficient costs JGN incurs in providing reference services and complying with regulatory obligations or requirements or making regulatory payments.

Even if the 1 per cent threshold was reasonable it is unreasonable that each individual pass through event should be subject to that threshold. At the very least it should be the aggregate value of events for a year that is tested against the threshold. The requirement that the threshold applies per event is also inconsistent with the revenue and pricing principles insofar as it further denies JGN a reasonable opportunity to recover at least the efficient costs JGN incurs in providing references services and complying with regulatory obligations or requirements or making regulatory payments.

The proposal that the threshold for Change in Tax events and UAG Adjustment events (classified as low administrative cost events) should be "where the change in cost is greater than the administrative costs of the Service Provider, users and the AER"[380] appears unworkable. Those costs cannot be known until an application has been made and assessed. Alternatively, JGN cannot know the administrative costs for users and the AER before making an application.

A Licence Fee Adjustment should be included in the low administrative cost event class given that the basis for and amount of any such change is readily verifiable.

[380] Draft decision, p. 314.

The definition of UAG Purchase Costs and the exclusion of Carbon Permit costs

JGN has not incorporated those aspects of amendment 13.3 requiring that the UAG purchase cost be defined, in essence, by the words "pursuant to the gas being purchased by the cheapest means (for example via an open tender, Short term trading market (STTM) or any other cheaper alternative)".

JGN maintains that its definition of UAG Purchasing Cost (now referred to in the AA as UAG Costs) i.e. "[the costs associated with] purchases of gas by the Service Provider as UAG, including costs for transmission haulage and other direct costs reasonably incurred by the Service Provider to acquire UAG through a competitive market or process" should be retained. The AER's amendment limits the allowable actual average price of UAG by adding "pursuant to the gas being purchased by the cheapest means (for example via an open tender, Short term trading market (STTM) or any other cheaper alternative)". The use of the terms "cheapest means" and "or any other cheaper alternative" in particular, renders the AER's limitation imprecise and unworkable.

JGN maintains that the costs associated with a CPRS are an uncontrollable cost that JGN will necessarily incur so variations in those costs should be recoverable as a cost pass through. However, rather than provide for adjustment for these costs as a component of the UAG Adjustment as proposed in its original AA proposal, JGN now proposes to establish the Carbon Pollution Reduction Scheme (CPRS) Event as a separate cost pass-through event in section 3.5C(c) of the AA.

Change in datum for assessment of Market Cost Events

JGN maintains that the datum against which Market Cost Events are assessed should be 1 July 2009 as proposed.

JGN was required to submit its original AA proposal on or before 26 August 2009. At that time it was not possible to forecast the full impact on costs of a Market Costs Event occurring after 1 July 2009.

The legislation, rules, procedures and changes to retail market procedures to accommodate the STTM in NSW were still being drafted at the time that JGN prepared its original AA proposal and have yet to be finalised. Under JGN's proposed datum, pass through would apply to unforseen changes to JGN's costs during the next AA period which arise from the finally drafted and enacted law. The AER's proposal to change the datum to 1 July 2010 could prevent JGN from recovering significant unforseen costs required to comply with the STTM as a Market Costs Event. That is, by changing the datum to 1 July 2010, JGN could be denied a reasonable opportunity to recover at least the efficient costs incurred in providing reference services.

13.3.6 Include a rounding convention – amendment 13.4

JGN has incorporated the following rounding convention in clause 3.4(b) of the access arrangement.

- all proposed tariff components before be rounded before being applied in a tariff variation formula
- the number of decimal places used for rounding a component will be consistent with that used for the relevant Reference Tariff component.

13.3.7 Provision for the AER to correct past errors – amendment 13.5

JGN has not incorporated this amendment in the form proposed by the AER.

The AER's intention in requiring this amendment is unclear. JGN understands the AER's intent to be that if there is an error in the calculation of tariffs in year t – 1, the error in the calculation of that tariff may be corrected for the purposes of determining what the dollar amount of the tariff in year t – 1 would have been but for that error, and the corrected dollar amount of that tariff is then an input into the calculation of tariffs for year t.

If JGN has misunderstood the AER's intention, JGN requests that the AER inform JGN of this as soon as possible and provide JGN with an opportunity to respond once JGN has been properly appraised of the AER's intent.

Following its review of the draft decision and the AER's statement of reasons for the draft decision, JGN does accept that, if an error is made in setting tariffs for one period such that all future tariffs would be affected (for example where an incorrect value of CPI is used), then the corrected value should be used in establishing those future tariffs. However, the error, if accepted as part of an approval, should stand in respect of the period to which the approval relates.

JGN notes that, apart from the AER's draft decision in its review of Country Energy's Wagga Wagga distribution network, there is no precedent for provisions of the type required by this amendment. The ESC, ESCOSA, ERA and QCA, as well as the AER itself, have all approved tariff basket TVMs in gas and/or electricity without such a provision. In particular, the AER did not include such a provision in its recent determinations for the New South Wales and South Australian electricity distributors.

The amendment as required is also unsatisfactory because:

- the AER may act if an error "appears" to have been made
- the action that the AER may take is unspecified and, on its face, could be unilateral.

For the reasons set out above, JGN does not consider that the amendment required by the AER that allows for the correction of otherwise approved tariffs is necessary and JGN does not propose to incorporate this amendment in its AA. To the extent that the AER maintains its position that the AA should be amended to provide for the correction of otherwise approved tariffs for the purposes of setting the dollar value of the tariffs in a later year, JGN has proposed some alternative drafting that is set out in the AA. JGN does not consider that the AER's proposed drafting is consistent with the AER's stated intent and therefore JGN has proposed alternative drafting that JGN considers is consistent with the AER's stated intent. If an amendment is to be made that allows for correction of errors then, to be acceptable, it should be clear that:

- adjustments can only be made to correct demonstrated material errors that have effect beyond the period in which the error first has effect, and then only to correct the effect in those later periods
- any such adjustments to tariffs must be done within the framework provided in Section 3 of the AA including notification by JGN, discussions between JGN and the AER and approval by the AER. The AER must not make such adjustments to tariffs unilaterally.

13.3.8 Submission and approval of tariff variations – amendment 13.6

Following its review of the AER's draft decision, JGN has incorporated the requirements of amendment 13.6 in part.

Amendment requiring submission of annual tariff variation proposals by 15 April

JGN has amended section 3.4(b)(i) of the AA so that the date for submission of an annual tariff variation proposal is "on or before the 15th of April or the next closest business day prior to the commencement of the next Financial Year" but maintains that the words "or Tariff Classes" should be retained to be consistent with JGN's position that the TVM should permit JGN to introduce and withdraw tariffs (see section 13.3.2).

Amendment relating to submission of tariff variation proposals within a year

The AER has advised JGN that it made an error in its draft decision[381] and the AER's proposed amendment to section 13.4(b)(ii) is:

> Variation of a Reference Tariff within a Financial Year: Where the Service Provider proposes to vary one or more Haulage Reference Tariffs within a Financial Year it will submit a variation notice to the AER at least on (sic) 50 business days prior to the date upon which it intends to vary the amount of the Haulage Reference Tariff.

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381 Letter from the AER to JGN dated 3 March 2010, *Clarification of AER's reasons for draft decision*.

JGN has not incorporated the amendment which amounts to deleting the words "or Tariff Classes" from JGN's proposal. JGN maintains that those words should be retained to be consistent with JGN's position that the TVM should permit JGN to introduce and withdraw tariffs (see section 13.3.2).

Amendment relating to the introduction and removal of tariffs and tariff classes

JGN has not deleted section 3.4(b)(iii) of the AA. This clause relates to the introduction and removal of tariffs and tariff classes. JGN maintains that it is essential to the tariff basket approach that JGN have the flexibility to introduce and remove tariffs and tariff classes through the TVM as discussed in JGN's response to amendment 12.1 (see section 13.3.2).

Amendment of compliance requirement

JGN has not incorporated the amendment required to section 3.4(b)(iv) of the AA. The amendment amounts to the deletion of the words "new Haulage Reference Tariffs or" from JGN's proposal. JGN maintains that those words should be retained to be consistent with JGN's position that the TVM should permit JGN to introduce and withdraw tariffs (see section 13.3.2).

Amendments relating to the AER's process for reviewing tariff variation proposals

JGN has incorporated the amendments required to sections 3.4(d)(i) and 3.4(d)(ii) of the AA. However, as a consequence of accepting this amendment, JGN has added section 3.4(f)(ii) which provides for the situation where the AER's approval of an annual tariff variation proposal is delayed beyond the point where it can be implemented by 1 July. The additional provision is based on the presumption that, if the AER's approval of JGN's proposal is delayed, it is most likely to be because the AER is deliberating on the cost pass through elements of the proposal and that other aspects of the proposal can be implemented from 1 July as planned. To the extent that implementation of part of the proposal is delayed it will be allowed, with financing costs, as part of the next year's variation so that JGN is kept whole.

In making this change, JGN notes that IPART and the AER (for one year) has generally been able to approve tariff variations in good time under the current AA which provides for variation applications to be made at least 50 business days prior to the variations taking effect. For a 1 July change, that means the application must be made no later than about 23 April.

As a consequence of the change described above, it has been necessary to introduce an additional pass through event, being the "Held Over Cost Pass Through Event". This provides for any pass through amounts or adjustments that were not able to be incorporated in the setting of tariffs for year t are able to be incorporated (together with financing costs) in the setting of tariffs for year $t + 1$.

JGN has not incorporated the amendment required to section 3.4(d)(v). In JGN's view it is unreasonable and a denial of due process for the AER to have the right to "specify a tariff variation that is consistent with the Annual Tariff Variation Mechanism" without JGN being given the opportunity to:

- understand and test the AER's objections
- be heard
- amend its proposal in a way that addresses the AER's objections.

Amendment relating to default haulage tariffs

JGN has not deleted section 3.4(e) as required by the AER's draft decision. It is very unlikely that JGN would fail to submit a tariff variation proposal in accordance with other provisions of the AA. However, it is reasonable to provide for that possibility. JGN maintains that section 3.4(e) (now 3.4(f)(i)) is an appropriate provision but with the following changes:

- replace the phrase "at least 30 business days prior to the commencement of the financial year" with "on or before the 15th of April or the next closest Business Day prior to the start of the next Financial Year"
- add a qualification that, for purposes of the scaling referred to in section 3.4(f)(i), the term V_t will be taken to equal one (1) so that the scaling will result in tariffs being adjusted only for CPI and X.

Amendment of section 15.4.2 of the AAI

JGN has amended section 15.4.2 of the AAI as required by the AER's draft decision.

13.3.9 Calculation of the CPI adjustment – amendment 13.7

JGN has amended section 3.5B of the AA as required by the AER's draft decision.

13.3.10 Verification of Gas Quantity inputs in the tariff variation formula – amendment 13.8

JGN has added a new section 3.4(c)(iv) in the AA as required subject to the costs of obtaining the independent audit or verification being allowed as a recoverable cost.

13.3.11 Explanation of how the tariff variation proposal complies with the TVM – amendment 13.9

JGN has amended section 3.4(c)(ii) in the AA as required by the AER's draft decision except that it has used the words "comply with the Tariff Variation Mechanism" instead of "have been estimated".

It is not clear to JGN how the words "demonstrating how the proposed tariffs have been estimated" in the amendment as proposed could be applied in practice.

13.3.12 Amendment of section 16.6 of the AAI to describe cost pass through categories consistently with section 3.5C of the AAI – amendment 13.10

JGN has amended section 16.6 in the AAI so that it is consistent with the amendments that it has made to section 3.5C of the AA as described in section 13.3.5.

13.3.13 Addition of factors to be taken into account by the AER is assessing a cost pass-through event – amendment 13.11

JGN has incorporated this amendment by including a new section heading "(e) Cost Pass-Through Event: Notification by the Service Provider and assessment by the AER" in section 3.4 of the AA and adding a new paragraph 3.4(e)(iv) which adopts the form of rule 6.6.1(j) in the national electricity rules which sets out the factors that the AER must take into account in assessing cost pass through events under those Rules. As noted previously, rule 6.6.1(j)(4) provides specifically that the AER must take into account "the time cost of money based on the *weighted average cost of capital*" when assessing a cost pass through amount.

13.3.14 Addition of factors to be taken into account by the AER is assessing a cost pass-through event – amendment 13.12

JGN has incorporated:

- provisions that address the amendment as it relates to cost pass-through events in paragraph (iii) in the new section 3.4(e) of the proposed AA. In drafting this paragraph 3.4(e)(iii), JGN has adopted the form of rule 6.6.1(c) in the national electricity rules. That rule sets out the information that a service provider must provide to the AER when seeking approval of a positive pass through amount

- an additional paragraph 3.5D(e) in section 3.5D of the proposed AA that addresses the amendment as it relates to UAG adjustments.

As to the requirement that an application for a Change in Tax Event "be supported by information about the financial impact of the taxation changed event from the relevant taxation or regulatory authority", that requirement is, in JGN's view, unworkable. For example, if there was a change in the rate of payroll tax (or any other tax for that matter), the change in tax payments for the periods before and after the rate change would be due in part to the rate change and in part due to the change in the size of JGN's business between periods (the change in the size of JGN's payroll in the case of a change in payroll tax).

The recoverable amount attributable to a Change in Tax Event will not be reflected directly in JGN's actual tax payments or in an audited tax statement. Ascertaining the recoverable amount will require analysis based on knowledge of the business and the amounts of tax paid. Moreover, where the Change in Tax Event is the result of a change in the corporate tax rate or other aspects of taxation that would normally be allowed for on a benchmark basis, for example, in the WACC calculation, the amount of the adjustment will be calculated on a benchmark basis and not by reference to JGN's actual tax position.

If the cost of Change in Tax Events is to be recovered after the event, then a WACC adjustment is all the more important.

JGN has adapted the language of the amendment in recognition of these issues.

13.3.15 Limiting frequency of tariff changes for Change in Tax and UAG Adjustment Events – amendment 13.13

JGN has incorporated a new paragraph (vii) in section 3.4(d) of the AA to specify that tariff changes on account of Change in Tax events, Weather Variation adjustments, UAG adjustments, and Licence Fee adjustments will occur only once a year on 1 July.

JGN has extended the limitation to include Weather Variation adjustments and Licence Fee Events because, as explained in section 0 JGN maintains that those events should be passed through automatically via the TVM.

13.3.16 Time within which JGN must notify the AER of the occurrence of a Cost Pass-through Event – amendment 13.14

JGN has incorporated a new paragraph (i) in section 3.4(e) of the AA to require that JGN notify the AER of a cost pass-through event other than a Change in Tax Event and Held Over Cost Pass Through Event, within 90 business days of incurring the costs of the event. As the pass through events that make up the amount of any Held Over Cost Pass Through Event will have been assessed by the AER when they were notified to the AER as any of the other pass through events, it would be circular and inefficient to subject the Held Over Cost Pass Through Event to the notification requirements.

JGN has not included UAG Adjustment Events in the list of exceptions because, as explained in section 13.3.4, it maintains that UAG Adjustments (as well as Licence

Fee Adjustments) should be passed through automatically via the TVM. As discussed previously, JGN does not classify Licence Fee adjustments, UAG adjustments and Weather Variation adjustments as cost pass-through events.

JGN has also added a provision (paragraph 3.4(e)(ii)) that deals specifically with Declared Retailer of Last Resort (ROLR) Event. For those events JGN proposes to provide an estimate the effect of the event as part of an initial notification within 90 Business Days and full details in a final notification no later than 120 Business Days after the event. The allowance of additional time to finalise full details of ROLR events is consistent with established arrangements in Victoria.

Finally, as explained in section 13.3.14, JGN has added provisions that address the requirements of amendment 13.12 as it relates to cost pass-through events.

13.4 Amendments to the access arrangement proposal and information

JGN has made extensive changes throughout section 3 of its revised AA revision consistent with JGN's responses to amendments 12.1 and 13.1 to 13.14 as described above.

14 Non-tariff components

- JGN proposes a change to the way that terms and conditions of access are presented in the AA. The terms and conditions are now in a contractual form that is designed to facilitate the contracting process between JGN and prospective users.
- The AER requires 38 amendments to the non-tariff conditions contained in JGN's original AA proposal. JGN has incorporated some without modification and some with modification, and not incorporated others.

JGN's current AA contains a description of the minimum terms and conditions for access to the network. These are "policy based" and are interspersed throughout the AA as high level principles as the basis of contract negotiation.

The proposed AA contains terms and conditions that act as a reference service agreement to cater for all prospective users (supplying both small and large end consumers) where they are seeking reference services. The terms and conditions are in contractual form.

This change is designed to make the process of contracting with JGN more straight forward for both JGN and prospective users. JGN considers that the reduction in administrative burden associated with the new form of the terms and conditions and the enhanced certainty for JGN and users promotes the NGO.

14.1 Summary of AER draft decision

The AER draft decision provided that, in order to make the proposal acceptable to the AER, JGN would be required to amend the access arrangement proposal to make the amendments set out in Table 14-1.

Table 14-1: Amendments the AER required in its draft decision – non-tariff components

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
14.1	Amend the AA and AAI to state the terms and conditions on which the ancillary services reference service will be provided	Incorporated with modifications	Section 14.2.2
14.2	Amend the AA and AAI to state the terms and conditions on which the legacy services reference service will be provided.	Not incorporated	Section 14.2.3

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
14.3	Amend the RSA to include that in the event a user believes that meter data is incorrect, they shall notify the SP in writing who will then investigate and advise the user of its findings without delay.	Incorporated with modification	Section 14.2.4
14.4	Amend AA to require that all variations of a term or condition of the AAI (including the Reference Services Agreement) should be submitted to the AER for approval under r65 of the NGR.	Incorporated	Section 14.2.1
14.5	Amend AA to delete clauses 2.2C(c) to (f) regarding the amendment of the Reference Services Agreement.	Incorporated	Section 14.2.1
14.6	Amend RSA to replace 1.4B on amendments to the RSA, with a requirement that such amendments will vary the terms of the RSA effective 10 business days from the date of written notice unless the Service Provider can satisfy the AER that it cannot comply with this timeframe.	Incorporated	Section 14.2.1
14.7	Amend RSA 1.4 to delete ambiguities from words "or is deemed to have approved" and "(or a replacement of the RSA)"	Incorporated	Section 14.2.1
14.8, 14.9, 14.10	Amend RSA so that any changes of a material nature must be amended via a revision of the AA under the NGR - includes gas quality specifications, pressure specifications at receipt points and gas balancing arrangements.	Not incorporated	Section 14.2.5
14.11	Amend RSA to delete the words “by the service provider” from the definition of “Reference Tariff Schedule” in the RSA.	Incorporated	Section 14.2.1
14.12	Amend RSA to include definition of Variation Process to mean an AA revision under the NGR	Not incorporated	Section 14.2.5

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
14.13	Amend RSA to incorporate JGN modified chargeable demand proposal - reduction in chargeable demand will take effect from the first day of the calendar month immediately following the date of receipt of the complete Reduction Request	Incorporated with modification	Section 14.2.7
14.14, 14.15	Amend RSA to remove JGN discretion to apply a different balancing arrangement	Not incorporated	Section 14.2.8
14.16	Amend RSA to include that separate forecasts for balancing only apply where the market does not set out a nomination timetable	Incorporated with modification	Section 14.2.8
14.17	Amend RSA to include that separate forecasts for balancing only apply where the market does not set out a nomination timetable	Incorporated	Section 14.2.1
14.18	Correct typographical errors in the RSA	Incorporated	Section 14.2.1
14.19	Correct typographical errors in the RSA	Not incorporated	Section 14.2.9
14.20	Amend RSA to include requirement to consult with user to determine whether their customer is intending to increase load and/or change their usage pattern when exercising discretion to downgrade basic metering equipment.	Incorporated with modification	Section 14.2.1
14.21	Amend RSA for metering access – amending process for ensuring that measuring equipment is in a safe and accessible area	Incorporated with modification	Section 14.2.12
14.22	Amend RSA re: estimating meter read where access is not possible	Incorporated	Section 14.2.1
14.23	Amend RSA for metering access – 1 days' written notice for safety issues and 5 days' written notice for other issues before JGN relocates measuring equipment at User's reasonable cost.	Incorporated	Section 14.2.1

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	Description		
14.24	Amend RSA for right to modify meters (at user’s cost) for safety - subject to reasonable notice if possible	Incorporated with modification	Section 14.2.13
14.25	Amend RSA so that JGN can only recover uncharged amounts if the user can pass costs through to its customer.	Incorporated with modification	Section 14.2.14
14.26	Amend RSA on scheduled interruptions to delete the word ‘or’ in clause 25.2(c)(i) of Schedule 3 in the access arrangement proposal and replace it with the word ‘and’.	Incorporated	Section 14.2.1
14.27	Amend RSA so that JGN is not able to terminate the agreement for non payment of disputed amounts	Incorporated with modification	Section 14.2.15
14.28	Amend AA to remove User's liability for and indemnity in respect of any damages or claims in connection with decommissioning of delivery station or temporary disconnection and reconnection or suspension of service arising from Jemena's negligent conduct.	Not incorporated	Section 14.2.15
14.29	Amend RSA to remove "no warranty" and "scope of liability" clauses	Incorporated	Section 14.2.1
14.30	Amend AA to alter definition of "demand customer list" to remove discretion of service provider as to its form	Incorporated	Section 14.2.1
14.31	Amend AA for capacity trading requirements to refer to rule 105(3) of the NGR and to add an example as provided in draft decision	Incorporated	Section 14.2.1

AER required amendment		JGN revised AA revision	Explanation in this document
Amendment	**Description**		
14.32, 14.33, 14.34	Amend AA extensions and expansions policy so that: (1) for any "high pressure" expansion—a pipe longer than 1km to an unreticulated postcode area—not included in the calculation of reference tariffs, JGN to apply for a ruling on the coverage status of the extension. (2) any extension of expansion that is not high pressure, are covered and JGN is to provide annual reports to AER reporting on such extensions and expansions	Not incorporated	Section 14.2.16
14.35	Amend AA to add requirement to notify AER of any proposed surcharge to be levied on users of incremental services and designed to recover non-conforming capex or a specified portion of non-conforming capex.	Not incorporated	Section 14.2.16
14.36	Amend the AAI to reflect amendments 14.32 to 14.35	Not incorporated	Section 14.2.16
14.37	Amend AA for terms on which a user may change a receipt point or delivery point	Incorporated	Section 14.2.1
14.38	Amend AA to create trigger event to review AA with 6 months notice where there are inconsistencies with changes to terms and conditions of access between the approved AA and the NGL or NGR under the following circumstances: (1) amendment to NGL or NERL or NERR (2) STTM does not operate as anticipated and AA does not accommodate the STTM	Not incorporated	Section 14.2.17

14.2 JGN response to AER draft decision

14.2.1 Summary of JGN's response

The AER requires 38 amendments to non-tariff conditions contained in the Reference Service Agreement (RSA) which forms Schedule 3 of the AA. Of those, JGN has incorporated the following amendments in the form the AER in the draft decision stated would be required in order to make the proposal acceptable to the AER:

Table 14-2 – Amendments that JGN has incorporated

Amendment No	Subject matter
14.4 to 14.7 and 14.11	Amendment of the Reference Services Agreement
14.17	Typographical Error - provision of forecasts of withdrawals
14.18	Typographical errors
14.22 and 14.23	Consequence of no access
14.26	Scheduled interruptions
14.29	Liability and indemnity
14.30	Definitions
14.31	Capacity trading requirements
14.37	Terms and conditions for changing receipt and delivery points

Of the remainder, JGN has incorporated some of the amendments with modifications and has not incorporated others. The reasons for the positions that JGN has taken in respect of these other amendments are presented in the following sections.

14.2.2 Classification of Ancillary Services – amendment 14.1

Amendment 14.1 requires JGN to state the terms and conditions on which the ancillary services reference service will be provided.

With the exception of special meter reads, all activities that are associated with the ancillary fees set out in schedule 2 are already dealt with under the RSA and the activity description in schedule 2 to the AA. Requests for service, temporary disconnections, permanent disconnections and decommissioning are dealt with in relation to the reference haulage service (clauses 3.1; 24.1; 15.8). Requests for service are dealt with in the terms and conditions for the meter data service (clause 17.1(b)) but special meter reads are only mentioned in the ancillary fee schedule.

The activities associated with the ancillary fees are diverse activities which can only be efficiently provided as part of the reference haulage service or meter data service. The users that require these activities are the same users that require access to the reference haulage and meter data services.

To make it clearer that ancillary activities are not independent of the reference haulage service and meter data service, JGN has made the following changes to the RSA:

- A new clause 17.1(j) has been added to the Meter Data Service to explicitly address special meter reads. A consequential change has been included in clause 17.1(k).

- The headings of clauses 24.1 and 15.8 have been changed so that it is clearer that these clauses concern activities that are subject to ancillary fees. A consequential change has been made to clauses 15.8(a), (b) and (d).

In addition, JGN has made changes to the service descriptions in the AA, and now treats the individual ancillary fees as reference tariff components of either the reference haulage service or the meter data service. JGN has elected to maintain the term “ancillary fee” because the term is useful due to its common past usage to identify transaction charges.

14.2.3 Classification of Legacy Services – amendment 14.2

Amendment 14.2 requires JGN to include legacy services as reference services. JGN has not incorporated the required amendment.

The legacy services are unlikely to be sought by a significant part of the market during the term of the AA, in particular as a result of the commencement of the STTM and the reclassification by the National Competition Council of the Northern Trunk (Wilton to Newcastle) and Southern Trunk (Wilton to Wollongong) pipelines as distribution pipelines[382]. The legacy services therefore do not fall within the definition of Reference Services and should not be included in JGN’s AA as Reference Services. JGN has removed the references to “Legacy Services” and associated pricing guideline from the revised AA proposal. JGN has amended the defined term "Legacy Services" in the RSA to "Pre-STTM Contracts/Services" so that it is clear that these services are not reference services for the purposes of the AA. It is necessary to refer to previous forms of contracts in the RSA to deal with the transition between contracts.

Pre-STTM Services are the services that are provided as reference services under JGN’s current AA as approved by IPART in 2005. These services are point to point services, that is, they are defined by reference to receipt points and delivery points (see JGN’s current AA pp. 5-31). They are provided by JGN under existing contracts with users. Under those contracts, JGN must comply with a number of obligations that relate specifically to receipt points:

- receive gas from or on behalf of a user at specified receipt points

- transport gas from a specified receipt point to a specified delivery point

382 NCC, *Jemena Pipeline Reclassification – National Gas Law: Application by Jemena Gas Networks (NSW) Limited for Reclassification of the Northern Trunk and Southern Trunk Pipelines*, 29 June 2009.

- permit the specified receipt points to be changed or new receipt points added
- comply with gas balancing obligations.

Similarly, users are subject to a range of obligations that relate to receipt points, including:

- *Gas source* – The user must have measures in place to prevent gas that does not meet the specification from being delivered at the receipt point.
- *Specifications* – The user is required to ensure that gas delivered to the receipt point complies with the specifications.
- *Title* – The user warrants it has title to gas at the time it is delivered at the receipt point.
- *Receipt Point Nomination* – Users are required to have gas delivered on their behalf to the network and are required to nominate the quantity of gas deliveries each day at a receipt point basis.
- *Operational Balancing Cost* – Users are required to pay JGN for its portion of the operational balancing cost.
- *Receipt Point Forecast* – Users are required to provide forecasts at each receipt point on a daily basis.
- *Receipt Point Deliveries* – Users are required to deliver or cease to deliver gas to the specified receipt points.

The STTM is due to commence in early June 2010 and will have a direct and fundamental effect on JGN's ability to continue to provide services that are defined by reference to specific receipt points and delivery points. It will also affect the ability of users to comply with receipt point related obligations.

Under the STTM, gas will be scheduled for the hub as a whole. Shippers inject gas into the network and users purchase gas for delivery at a delivery point. As a consequence of these arrangements, JGN will not be able to provide any point to point transportation services and users will not be able to comply with receipt point related obligations under their current agreements. Therefore, even if it were possible that JGN could continue to provide legacy services as they are currently defined in JGN’s current AA following the commencement of the STTM, it is highly unlikely that any part, let alone a significant part, of the market will seek Pre-STTM services upon commencement of the STTM. The legacy services do not fall within the definition of Reference Services[383] and therefore cannot be included as Reference Services in JGN's AA for the next AA period.

The Draft Decision does not consider how the STTM will affect JGN's ability to continue to provide Pre-STTM services; or a user's ability to continue to comply with their obligations in relation to receipt points under a Pre-STTM service if that service was supplied.

Finally, JGN notes that the Standing Committee of Officials clarified the intended application of what are now rules 48(c) and 101 in the course of developing the NGR. The Australian Pipeline Industry Association had raised an issue in relation to clause 50(c) of the second exposure draft of the NGR as follows:

> The requirement for a service provider to describe all services that "are… sought by a significant part of the market" as reference services might inadvertently require service providers to offer currently contracted services as reference services. [384]

This is precisely the issue that concerns JGN. The SCO's response was:

> **Accepted -** The NGR requirements for the specification of reference services in access arrangements will return to a future-looking approach, where access arrangements must specify as reference services all services "that are likely to be sought by a significant part of the market." [385]

JGN is currently in the process of liaising with users to put in place a temporary arrangement that would enable the continued delivery of gas in the period between the commencement of the STTM and the commencement of the AA (at which time it is anticipated that JGN and each user will enter into a new agreement in the form of the new Reference Service Agreement). Users are aware that their existing agreements are not suitable for operation under the STTM and corrective action is required ahead of the commencement of the STTM.

14.2.4 Notification and investigation of meter data matters – amendment 14.3

Following its review of the draft decision, JGN has incorporated amendment 14.3 with two drafting changes:

1. the reference to clause 17.7 has been changed to be a reference to clause 17.5 (clauses 17.5 and 17.6 have been deleted as a consequence of incorporating amendment 14.29)

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[383] NGR, s101(2) and s59(2), Example 2

[384] Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 9.

[385] Standing Committee of Officials, *SCO Responses to Stakeholder Consultations on the National Gas Rules*, undated, p. 9.

2. the word "their" has been replaced with the word "its".

14.2.5 Amendment of the Reference Services Agreement – amendments 14.8 to 14.10 and 14.12

JGN has not incorporated amendments 14.8 to 14.10, for the reasons set out below. JGN has not incorporated amendment 14.12 either, since that amendment is related to amendments 14.8 to 14.10.

JGN acknowledges the AER's view that any variations of the AA (which includes the RSA), once it is approved, must be made in accordance with Division 10 of Part 8 of the NGR. However, JGN does not accept that the variations contemplated by clauses 10.1(a)(ii), 14.9(a) and 24.2(a)(ii)(B) of the RSA amount to variations of the AA. Rather they are proposed to be variations of the bilateral contracts between JGN and users which have been entered into using the RSA as the standard form of contract. These variations will be made by notification in accordance with the agreed terms of each bilateral commercial agreement. Such notifications will not vary the standard form of RSA contract set out in the AA, but will be commercially enforceable under the terms of the bilateral agreement between JGN and the user.

There is a distinction between the AA and the contract between JGN and a user. The AA contains a standard set of terms and conditions (the RSA) which form the basis of the separate bilateral contracts that JGN will enter into with each user. It is those contracts and not the RSA contained in the AA that will govern the relationship between the parties. The commercial contracts do not form part of the AA and can be amended by agreement between the parties. A variation to a transportation agreement that is made by commercial agreement between two parties does not vary the standard form of RSA as set out in the access arrangement on which the contract was originally based. Such variations are common in commercial contracts and do not amount to a variation to the AA. Amendments 14.8 to 14.10 fail to recognise that distinction.

The changes to bilateral contracts contemplated by 10.1(a)(ii), 14.9(a) and 24.2(a)(ii)(B) are all operational matters which are subject to variation under JGN's current transportation contracts through the issuing of a notice by JGN. A change which required such variations to be the subject of an access arrangement variation, with its associated delays, would threaten the safe and reliable operation of the network.

Clause 10.1(a)(ii)

Clause 10.1(a)(ii) deals with the ability of the network operator to vary the gas quality specification to the extent that such a matter is not dealt with under relevant law. Matters of gas specification which are not prescribed under law include

- *Odourant levels* – NSW law requires the reticulator to determine the level to which gas must be odorised (see clause 29 of Gas Supply (Safety and Network Management) Regulation 2008. Odourant is a critical control for network safety.

- *Permissible variations* – Australian Standard 4564 Specification for General Purpose Natural Gas does not address allowable excursions from the specification (see AS4564 Appendix B – Matters that may be considered in Contracts)

Under the Gas Supply (Safety and Network Management) Regulation 2008, JGN has defined responsibilities for management of gas quality. Without clause 10.1(a)(ii) JGN would be unable to make lawful amendments of the specification contractually enforceable which would create operational risk for safety and integrity of the network. JGN currently has this contractual right in network contracts, and it is not appropriate that JGN's right (and obligation) to manage the operational safety and reliability of the network should be subject to an access arrangement variation.

Clause 14.9(a) and 24.2(a)

Clause 14.9(a) and 24.2(a) deal with the minimum and maximum pressures for delivery of gas at network receipt points. Safe and reliable operation of the network depends on the pressure of gas presented to the network. In the case of many receipt points JGN does not have control of pressure regulating infrastructure and therefore depends on its contractual rights under network contracts to control the range of receipt point pressures. Examples of where JGN has used its contractual rights to vary receipt point pressures include:

- reducing maximum and minimum pressures in the network to accommodate maintenance of upstream pipelines

- reducing the maximum allowable pressure in the Wilton network to maintain safe operation during third party works which are exposing mains in a critical section of the network. Maximum allowable pressures will be reinstated once third party works are complete.

JGN currently has the contractual right to alter delivery pressures in network contracts and it is not appropriate that JGN's right (and obligation) to manage the operational safety and reliability of the network should be subject to an access arrangement variation.

Similarly the establishment of a new receipt point should not require an amendment of an access arrangement. The intent of an access arrangement is to facilitate access, including the connection of other pipelines. Requiring an access arrangement variation to accommodate a new receipt point would prevent the efficient provision of access. Amendment 14.10 would have that effect by preventing JGN from issuing a notice (in accordance with a bilaterally agreed contractual right) establishing a new receipt point. Note that JGN will need to issue such a notice when the new Albion Park receipt point comes on line in late 2010.

As noted above, JGN accepts that as the example standard contract (the RSA) forms part of the AA, amendments to the RSA can only be made in accordance with Division 10 of Part 8 of the NGR.

However, JGN does not consider that the exercise of a right under a bilateral contract to give notice of changes to operational matters such as the gas specification[386], minimum and maximum pressure specifications[387], and gas balancing[388] (the subject matter of the clauses affected by amendments 14.8 to 14.10) amounts to an amendment to the AA.

Amendments 14.8 to 14.10 would have the effect of requiring the AER to approve operational changes to those bilateral contracts. That would not be consistent with the NGO. It is also inconsistent with the agreements that are currently in place under the current AA, which permit JGN to change pressure obligations and the gas specification unilaterally[389]. That is, agreements that are currently in place contain provisions that have the same effect as clauses 10.1(a)(ii), 14.9(a), 24.2(a)(ii)(B) and Annexures 3 and 4 of the RSA[390].

In JGN's experience, some of the changes that are permitted under the clauses affected by amendments 14.8 to 14.10 may need to be introduced at short notice and be in effect for a short period and affect some but not all users. It is in the long term interests of consumers of natural gas in terms of safety, reliability and security of supply of natural gas for JGN, as the network operator, to be in a position to make and give effect to such operational decisions without first obtaining the AER's approval.

The principle reflected in the RSA is that JGN is the party responsible for setting the specifications and pressures to ensure the ongoing safe operation of the network and continuity of supply. Any specifications notified by JGN from time to time under its bilateral contracts with users in accordance with this principle do not amount to amendments to the RSA. To make this clear, having regard to the Draft Decision, JGN has incorporated amendments to clauses 10.1(a)(ii) and 28.2(a)(ii)(B) to:

386 RSA, clause 10.1(a)(ii).

387 RSA, clauses 14.9(a) and 24.2(a)(ii)(B).

388 RSA, annexures 3 and 4.

389 See, for example, paragraph (c) of Schedule 5 of the current AA (p. 111) and clause 11 of the terms and conditions on page 85.

390 See condition 6.1(a) of the Tariff Service Agreement and clause 7.1 of the MDPSA.

1. insert obligations for the user to comply with such specifications and pressures as are notified by JGN from time to time

2. describe the operational specifications in annexures 2 and 6 as the initial specifications

3. amend annexures 3 and 4 so that JGN will provide notice to the user of any actions required by the user and JGN in the event of a change of circumstances in order to ensure the continued safety, reliability and security of supply of natural gas.

It is important to recognise that the terms and conditions of the RSA have no effect unless they are executed as a bilateral agreement between the parties whereupon, the terms and conditions become a commercial agreement, and it is that agreement that is varied by the notifications of operational matters contemplated in JGN's original AA proposal. The standard form of RSA as contained in the AA is not varied by such a notice – hence the AA is not inadvertently varied.

14.2.6 Decreases in chargeable demand – amendment 14.13

JGN has incorporated amendment 14.13 but with the word "its" instead of "their".

14.2.7 Gas balancing – amendments 14.14 and 14.15

JGN has not incorporated amendments 14.14 and 14.15. Instead JGN has incorporated amendments to clause 7.4 to clarify:

4. that the clause is not intended to operate to the exclusion of any gas balancing mechanisms that JGN is required to comply with at law

5. that if a gas balancing mechanism introduced by AEMO meets the operational requirements of the network, that mechanism will apply rather than the mechanism set out in the Gas Balancing Annexures

6. that JGN will notify the user as to the gas balancing mechanism that will apply.

In requiring the amendment, the AER is concerned that clause 7.4 enables JGN to decide whether or not it will apply a gas balancing mechanism that has the force of law and does not consider it appropriate for the AA to give JGN that discretion. [391] That is not the intention of clause 7.4. It is JGN's intention to comply with any gas balancing mechanism that may be established at law.

If a gas balancing mechanism is introduced during the AA period it is most likely that it will be established by AEMO under the STTM. In particular, the STTM

[391] Draft decision, p. 330.

makes provision for a Market Operator Service (**MOS**) scheme. JGN understands that the MOS scheme is essentially a financial allocation of the cost of ex ante scheduling variances in the wholesale gas market (i.e. a financial allocation of commodity price) rather than a physical balancing scheme (i.e. a scheme that aims to ensure that line pack in the network remains sufficient to allow for continuity of supply).

The reason for this understanding is that the STTM leaves responsibility for the ongoing safe and reliable operation of the network in the hands of JGN. This is clearly stated in the Industry Guide to the STTM issued by AEMO in July 2009, which provides:

> AEMO has no statutory responsibility for managing gas quality or system security in the hub. The distributor remains responsible for the operation of the distribution system during a supply shortfall and the STTM scope does not include involuntary curtailment of distribution end-customers [392].
>
> The STTM has no involvement in any distribution processes for managing the scheduling of withdrawals from a hub[393]

The intention of clause 7.4 is to:

- implement a gas balancing mechanism provided by AEMO if the mechanism meets the network's operational requirements

- make provision for a gas balancing mechanism if AEMO does not provide a gas balancing mechanism, or if the mechanism provided by AEMO does not meet the operational requirements of the network

- give notice to Users as to the gas balancing mechanism to apply (that is, the mechanisms in the Gas Balancing Annexures or any mechanism under the STTM). It is important that notice be given so that there is no ambiguity as to which contractual provisions are in effect at any one time.

This is consistent with the NGO. It is in the long term interests of end users for JGN to be able to determine the balancing arrangements required to ensure the safe and reliable operation of its network. As noted above AEMO as STTM operator has no statutory responsibility for network balancing or for that safe and reliable operation of JGN's network.

JGN has proposed amendments to clause 7.4 to clarify:

- that the clause is not intended to operate to the exclusion of any mechanisms JGN or the user is required to comply with at law

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392 AEMO, *Industry Guide to the STTM, Version 2.0*, 11 March 2010, p. 10.

393 AEMO, *Industry Guide to the STTM, Version 2.0*, 11 March 2010, p. 24.

- that JGN will notify the user as to the gas balancing mechanism that will apply, as described above.

14.2.8 Provision of forecasts of withdrawals – amendments 14.16

Following its review of the draft decision, JGN has incorporated amendment 14.16 in modified form as follows:

> And clause 7.5(f) only applies insofar as the AEMO or a relevant industry scheme does not set out a timetable for the User to provide Forecast Withdrawals as required under this clause 7.5.

JGN has excluded the reference to sub-clauses 7.5(c)-(e) from the amendment because those sub-clauses do not relate to a timetable.

14.2.9 Typographical errors – amendment 14.19

JGN has not incorporated amendment 14.19. The date "1 July 2009" is not a typographical error and was intentionally selected to ensure that users had sufficient flexibility to consult with their customers during the establishment phase of JGN's new tariff structures and new contracts. The effect of the required amendment would be that a user may not be able to request re-assignment of a delivery point to another tariff within 12 months of the date of bulk transfer. The assignment date is used to determine whether 12 months have elapsed since a delivery point was most recently assigned to its current tariff class (the 12 month requirement is set out in JGN's Reference Tariff Policy and is a common waiting period in gas and electricity for tariff re-classification).

It is envisaged that users may wish to consult their customers on tariff options after the user has completed the contractual transition to a new contract based on the RSA. In such a circumstance the user may wish to request re-assignment to a different tariff almost immediately after the delivery point was initially assigned to a tariff in accordance with the bulk transfer arrangements. With JGN's original proposal, the assignment date will always be deemed to be at least 12 months or more in the past, allowing further re-assignment. With the AER's proposed amendment, users may have to wait until July 2011 before requesting re-assignment in the same circumstances.

14.2.10 Basic metering equipment downgrade at existing delivery station - amendment 14.20

JGN has incorporated amendment 14.20 but with the words "the User's Customers" instead of "their".

14.2.11 Safe access to measuring equipment – amendment 14.21

JGN has incorporated amendment 14.21 with modification. JGN has:

- deleted the reference to clause 16.1(b) from the new clause 16.1(d) in recognition of the fact that JGN has no rights to take any action under clause 16.1(b) and so the inclusion of the reference to clause 16.1(b) in new clause 16.1(d) (which deals with giving notice before action JGN takes action) is redundant

- added the proviso to the new clause 16.1(d) that it not be required to give notice in situations where immediate access is required due to safety risks or an emergency.

14.2.12 Right to alter measuring equipment – amendment 14.24

JGN has incorporated amendment 14.24 but with a further amendment to clause 16.8 to clarify that the provision of reasonable time in which the user may rectify the issue only applies where the issue relates to the user's compliance with the provisions of the RSA. This amendment is intended to make it clear that there are a number of reasons why changes to the measuring equipment might be required, many of which are incapable of being corrected by the user.

14.2.13 Overcharges and undercharges – amendment 14.25

JGN has incorporated amendment 14.25 with three drafting changes:

- numbering the clause 22.8(a) rather than (aa)

- using the term "correct amount pursuant to clause 22.8(b)" in place of the term "additional charges". The term "additional charges" suggests that the amounts are charges in addition to the amounts payable for the services under the RSA whereas overcharges and undercharges are corrections to ensure the amounts in fact paid accord with the charges payable under the RSA

- adding a proviso that the limitation does not apply to the extent the user has not complied with its obligations under relevant law or has not used reasonable endeavours to recover from end users or where the user is unable to recover due to the user's default. For example it would be unreasonable if JGN was unable to recover an amount because the retailer had failed to correctly issue an invoice to the customer.

14.2.14 Failure to pay – amendment 14.27

JGN has incorporated amendment 14.27 but with the reference to clause 26.2 (a typographical error) changed to refer to clause 22.6.

14.2.15 Liability and indemnity – amendments 14.28

JGN has not incorporated amendment 14.28.

Amendment 14.28 requires the deletion of the indemnities provided in clauses 15.12(b) and 24.3(b). The draft decision states that these clauses remove JGN's liability and impose indemnity liability upon the user for JGN's negligent conduct.

This is not the intent of those clauses. JGN accepts the principle that it should bear the liability where it has the potential to manage risk through its own conduct. However, the indemnity liability imposed on the user under clauses 15.12(b) and 24.3(b) is intended to cover damages or claims as a result of the cessation or suspension of the delivery of gas at the relevant delivery point, due to a temporary or permanent disconnection or decommissioning of the delivery point pursuant to clauses 15.8, 15.9 and 24.

JGN is not in the position to manage risk arising from such a cessation or suspension of gas supply. This is because the cessation or suspension of gas supply pursuant to clauses 15.8, 15.9 and 24 arises as a result of a user request or acts or events in respect of which JGN has no control as follows:

1. clauses 15.8 or 15.9 apply to the decommissioning of delivery stations by JGN at the user's request (clause 15.8) and the performance by the user of disconnections and reconnections at a delivery point (clause 15.9). JGN considers that the user is the party that has the potential to manage risks arising from decommissioning or disconnection at the user's request.

2. Similarly, clause 24 applies to the suspension of the delivery of gas at the user's request, if:

   – JGN has not received enough gas at the receipt point to meet relevant withdrawals

   – gas is delivered to a receipt point which is out of specification or does not comply with pressure requirements

   – the user is not a registered participant

   – the AEMO has instructed the user to suspend the delivery of gas at the delivery point.

   JGN is not in a position to manage any of these risks. The user is likely to have a contractual arrangement in place with the parties that deliver gas to the receipt points under the STTM and, unlike JGN, is a participant in the STTM. JGN considers that the user is therefore the party that has the potential to manage risks arising from the circumstances to which clause 24 applies.

The draft decision does not require any amendments to clauses 15.12(a) and 24.3(a). These clauses provide that JGN is not liable to the user or the user's customers for any damage in the circumstances stated in those clauses. JGN assumes that the words "Service Provider's actions" which appeared in proposed clauses 15.12(b) and 24.3(c) gave rise to the concern stated in the draft decision that these clauses impose liability on the user for JGN's negligence. To address this concern, consistently with the principle of assigning risk to the party who is best able to manage the risk and consistently with clauses 15.12(a) and 24.3(a), JGN proposes to:

1. amend clause 15.12(b) by deleting the words "Service Provider's actions" and replacing them with "cessation of the delivery of Gas at a Delivery Station upon the decommissioning of a Delivery Station or the disconnection of supply". This has the effect that the user is liable for and indemnifies JGN in respect of any damage or claims as a result of the cessation of the delivery of gas upon a decommissioning or disconnection that has occurred at the user's request. This is consistent with the scope of clause 15.12(a), which provides that "The Service Provider is not liable to the User or to the User's Customers for any Damage if a Delivery Station is decommissioned pursuant to clause 15.8 or supply is disconnected or reconnected pursuant to clause 15.9"

2. amend clause 24.3(b) by deleting the words "Service Provider's actions" and replacing them with "suspension of the delivery of Gas". This has the effect that the user is liable for and indemnifies JGN in respect of any damage or claims as a result of suspension of delivery of gas as a result of:

   – a suspension or temporary disconnection of supply at the user's request

   – JGN not receiving enough gas at the receipt point to meet relevant withdrawals

   – gas being delivered to a receipt point which is out of specification or does not comply with pressure requirements

   – the user not being a registered participant

   – the AEMO instructing the User to suspend the delivery of gas at the delivery point.

   This is consistent with the scope of clause 24.3(a), which provides that "The Service Provider is not liable to the User or to the User's Customers, employees, agents or contractors for any Damage if it suspends delivery of Gas under this clause 24".

These amendments limit the indemnity liability of the user to damages or claims arising from the suspension or cessation of delivery of gas pursuant to clause 15.8, 15.9 or 24. To the extent that any damage is suffered or incurred as a result of JGN's negligence (for example, damage to property at the site of the relevant delivery station that is caused by the negligent acts or omissions of JGN or its directors, officers, employees agents or contractors in performing the decommissioning or disconnection at the site), clause 28.2(b) would apply.

14.2.16 Extensions and expansions policy – amendments 14.32 to 14.36

JGN has not incorporated amendments 14.32 to 14.36.

The effect of amendment 14.32, if accepted, is that part of a network section could be declared to be uncovered. Apart from the fact that matters to do with coverage and uncoverage are properly the function of the NCC, JGN considers that declaring part of a network section uncovered through the operation of the proposed clauses 7(a)(i)-(v) would have undesirable consequences:

- The non-coverage of a part of a network section would require separate services to be provided through different parts of the same network section, and would result in different terms and conditions and processes applying to customers within that network section, as well as separate commercial operations (e.g. gas balancing).
- As well as customer discrepancies in price and services, retail market systems and structures would also have to adapt to multiple pipelines within a single network section. (The NSW retail market systems are structured around network sections.)

The avoidance of separate commercial operations for connected parts of the network, and associated inefficiencies, should be a primary consideration. The default should be that a network extension remains subject to the same access framework and market framework as the existing network section of which it is a part. If there are good reasons for an extension to be uncovered then JGN can make application to the NCC.

If prudency is the issue, then the AER already has sufficient power to deal with non-conforming expenditure.

In the event that the AER decides to reject JGN’s arguments and proceed with amendments 14.32-14.33, JGN proposes that, rather than specify the obligations proposed for clauses 7(a)(i)-(iv) by reference to “high pressure pipelines extension” they be specified by reference to “new network sections” where a new network section is a discrete sub-network that is:

- not an extension of a pre-existing network section and
- is exclusively supplied through a new connection to a transmission pipeline

where both the new network section and the new connection to the transmission pipeline are commissioned after 30 June 2010.

Amendment 14.34 would require JGN to submit a detailed annual report on "all extensions of low and medium [pressure] pipelines and expansions of the capacity of the Network during the financial year". As discussed in section 0, JGN considers it inappropriate and unnecessary for the AER to establish new information gathering powers through the AA approval process.

14.2.17 Acceleration of review submission date triggers – amendment 14.38

JGN has not incorporated amendment 14.38.

JGN accepts that if there is a change in law that means that a party can no longer comply with the RSA, the AA should be reviewed to ensure consistency with law. However, JGN considers the AER does not have the power to require a review of the AA if it considers the STTM "does not operate as anticipated" or if the RSA "does not effectively accommodate the STTM". The NGL and NGR do not give the AER any power to amend the AA in the event the AER makes an assessment that the STTM is not operating "as anticipated" or whether the AA "effectively accommodates the STTM".

To the extent a situation arises which results in the AA being inconsistent with the NGL, NGR, NERL, NERR, or the operation of the STTM, the most appropriate avenue for this to be dealt with is via Rule 65 which provides that a service provider may submit for the AER's approval a proposal for variation of the AA. As the AA (including the RSA) set out the fundamental basis for the provision of Reference Services by JGN and the acquisition of those services by users, JGN would have a very strong incentive to ensure that the AA is consistent with the requirements of the NGL, NRG, NERL, NERR and the STTM. This is consistent with JGN's position vis-à-vis legacy services not being Reference Services as the obligations on JGN and users in relation to legacy services as they are defined in the current AA are inconsistent with the STTM.

Additionally, it is simply inefficient to use the provisions in rule 51 (acceleration of review submission date) to deal with a situation where the AER perceives some tension between the AA and the NGL, NRG, NERL, NERR or the STTM. The examples given in relation to rule 51 indicate that rule 51 is intended to be used where there is a very significant event that fundamentally changes the nature and economics of the provision of pipeline services. A change in the law or the rules identified by the AER that "affects or impacts" upon reference tariffs does not fall within the types of events envisaged by rule 51. The types of events the AER is concerned with are appropriately dealt with through the pass through provisions in the AA to apply during the next AA period[394].

In addition, a review of the AA in these circumstances would not be consistent with the NGO. The NGO focuses on the efficient investment in, and use of, natural gas services. A natural gas service is defined as a pipeline service or the supply of natural gas or a service ancillary to the supply of natural gas. Amendment 14.38 is focussed on the operation of the STTM and its purpose appears to be to allow scope for the AA to be amended to better accommodate the STTM. The STTM is a financial market for the trading of gas. It uses bids, offers and forecasts to determine schedules and sets market prices and settlements based on those schedules and deviations from those schedules. It is not concerned with pipeline services and leaves responsibility for the physical delivery of gas and for reliability and security of supply with JGN. Whether the AA effectively accommodates the STTM or could more effectively do so is not relevant to the objective of promotion of efficient investment in, and use of, natural gas services.

14.3 Amendments to the access arrangement proposal and information

JGN has made extensive changes throughout its revised AA revision (including the revised RSA) consistent with JGN's responses to amendments 14.1 to 13.38 as described above.

[394] See "Market Costs Event".

Glossary

AA	access arrangement
AAI	access arrangement information
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
Access Economics	Access Economics Pty Ltd, ACN 123 967 966
Access Economics report	Access Economics, Forecast growth in labour costs, Report by Access Economics Pty Limited for the Australian Energy Regulator, 16 September 2009
ACIL Tasman	ACIL Tasman Pty Ltd, ACN 102 652 148
ACIL Tasman report	ACIL Tasman, Review of Demand Forecasts for Jemena Gas Networks NSW for the Access Arrangement period commencing 1 July 2010, Prepared for the Australian Energy Regulator, 2 February 2010
AEMA	Australian Energy Market Agreement
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
AGLGN	AGL Gas Networks Limited
AIC	average incremental cost
AMA	asset management agreement between JGN and JAM
AMP	asset management plan
APA	APA Group: the Australian Pipeline Trust and APT Investment Trust
A&O	administration and overheads
BASIX	Building Sustainability Index
BB	gas market bulletin board
BOM	Bureau of Meteorology
CEG	Competition Economists Group
capex	capital expenditure
CAPM	capital asset pricing model
CGS	Commonwealth government securities
CHOS	customer hours off supply
CLM Act	NSW Contaminated Land Management Act
COAG	Council of Australian Governments

CPI	consumer price index
CPRS	carbon pollution reduction scheme
COS	cost of service
current AA period	current access arrangement period: 1 July 2005 to 30 June 2010
customer	an end user of gas
DC	demand capacity
DCFR	demand capacity first response
DECC	Department of Environment and Climate Change
DMS	Data and Measurement Solutions
DMT	demand major end-customer throughput
DMTFR	demand major end-customer throughput first response
draft decision	Australian Energy Regulator, Jemena: Access Arrangement Proposal for the NSW Gas Networks 1 July 2010 – 30 June 2015 – Draft Decision, 10 February 2010
EBA	enterprise bargaining agreements
EBIT	earnings before interest and tax
EBS	Enterprise Business Services
EEH	energy efficient homes
EGP	Eastern Gas Pipeline
ENA	Energy Networks Association
ESF	enterprise support functions
E to G	electricity to gas hot water conversion
EUCS	energy use and conservation survey
FF	Fama-French three-factor model
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
Gas Supply Act	Gas Supply Act 1996 (NSW)
GCSS	guaranteed customer service level standards
GGAS	NSW Greenhouse Gas Reduction Scheme
GIS	geographic information system
GJ	gigajoule
GMC	Gas Market Company
GRMO	Queensland Gas Retail Market Operator
GSOO	Gas Market Statement of Opportunities
GSP	gross state product

HDD	heating degree days
ICB	initial capital base
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
ISC	Implementation Steering Committee
IT	Information technology
ITP	IT Plan
JAM	Jemena Asset Management Pty Ltd (ACN 086 013 461)
JGN	Jemena Gas Networks (NSW) Limited, ACN 003 004 322
JGN network	controller and operator of gas distribution networks in NSW
KPI	key performance indicator
LFS	Labour Force Survey
LGA	local government area
LRMC	long run marginal cost
MAOP	maximum allowable operating pressure
MCE	Ministerial Council on Energy
MCE/SCO	Standing Committee of Officials that support the MCE
MDQ	maximum daily quantity
MEM	market expansion mechanism
MEPS	mandatory energy performance standards
MMA	McLennan Magasanik Associates
MOS	Market Operator Service
MRC	Marsh Risk Consulting
MRET	mandatory renewable energy target
MRP	market risk premium
MSP	Moomba to Sydney pipeline
NCC	National Competition Council
NECF	national energy customer framework
NEET	NSW Energy Efficiency Target scheme
NEMMCO	National Electricity Market Management Company Limited
NERL	National Energy Retail Law, proposed
NERR	National Energy Retail Rules, proposed
next AA period	next access arrangement period: 1 July 2010 to 30 June 2015
NGCF	national gas connections framework
NGER	national greenhouse and energy reporting

NGERAC	National Gas Emergency Response Advisory Committee
NGL	National Gas Law, schedule of the National Gas (South Australia) Act 2008
NGO	national gas objective
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NPV	net present value
NPWG	Network Policy Working Group
NSW	New South Wales
O&M	operating and maintenance expenditure
opex	operating expenditure
ORC	optimised replacement cost
PB	Parsons Brinckerhoff
Pipelines Act	Pipelines Act 1967 (NSW)
Pipelines Regulation	Pipelines Regulation 2005 (NSW)
previous AA period	previous access arrangement period: 1 July 2000 to 30 June 2005
PJ	petajoule (10^{15} joules)
POTS	packaged off-take station
PRS	primary receiving station
PTRM	post tax revenue model
PV	photovoltaic
PwC	PriceWaterhouseCoopers
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RBSM	risk and benefit sharing mechanism
REC	renewable energy certificate
REMCo	South Australian Retail Energy Market Company
RET	renewable energy target
RFP	request for proposal
RIN	regulatory information notice under national gas rule 48(1)
RIS	Regulatory Impact Statement
ROLR	retailer of last resort
RPWG	Retail Policy Working Group
RSA	Reference Service Agreement

RSC	retail support clause
SAIDI	system average interruption duration index
SGC	Sydney Gas Company
SMP	Service Model Project
SPIAA	SPI (Australia) Assets Pty Ltd
SPM	service performance measure
STTM	short term trading market
subsequent AA period	subsequent access arrangement period: 1 July 2015 to 30 June 2020
t CO2e	tonnes of equivalent carbon dioxide
TJ	terajoule (10^{12} joules)
TVM	tariff variation mechanism
UAG	unaccounted for gas
user	a party who contracts with JGN for its use of JGN's pipeline services
VENCorp	Victorian Energy Networks Corporation
WAPC	weighted average price cap
WACC	weighted average cost of capital
WBS	work breakdown structure
WELS	water efficiency labelling and standards
Wilson Cook	Wilson Cook & Co Limited, NZ Company Number: 1232297
Wilson Cook report	Wilson Cook & Co Limited, Review of Expenditure of ACT and NSW Gas Distributors, Jemena Gas Networks (NSW) Ltd for the Australian Energy Regulator, December 2009
WOBCA	whole of business cost allocation

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List of appendices

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3b.6	CEG – Escalation factors affecting concrete forecasts – A report for Jemena Gas Networks – March 2010	Public
3b.7	Macromonitor – Forecasts of readymixed concrete costs – A report prepared for CEG – March 2010	Public

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9.1	Swier – JGN Access Arrangements 2010 – Expert opinion	Public

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9.10	NERA – Treatment of outsourcing arrangements for Multinet Gas Distribution Partnership	Public
9.11	NERA – Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins Critique for Envestra	Public
11.1	NIEIR – Natural gas projections NSW Jemena Gas Networks to 2015 – March 2010	Public
12.3	JGN – Long run marginal cost report	Public

List of supporting material – tax depreciation method

Name	File name	Date
ESC 2008 gas decision	ESC (Mar 2008) Final Decision for the Gas Access Arrangement Review 2008-12.pdf	Mar-08
ESC 2005 EDPR	ESC (Oct 2005) Final Decision for the EDPR 2006-10.pdf	Oct-05
ESC 2002 gas decision	ESC (Oct 2002) Final Decision for the Gas Access Arrangement Review 2003-08.pdf	Oct-02

List of supporting material – cost of debt

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Name	File name	Date

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List of supporting material – cost of equity

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