Jemena Gas Networks (NSW) Ltd

2015-20 Access Arrangement

Response to the AER's draft decision & revised proposal

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ABBREVIATIONS

AA	Access Arrangement
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator’s
B2B	Business to Business
B2M	Business to Market
CCP	Consumer Challenge Panel
Core Energy	Core Energy Group Pty Ltd
CPA	Commercial Pulse Accumulator
CPI	Consumer Price Index
CSG	Coal Seam Gas
DAE	Deloitte Access Economics
DDM	Dividend Discount Model
DRP	Debt Risk Premium
E to G	Electricity to Gas
EBSS	Efficiency Benefit Sharing Scheme
ECI	Electronic Corrector Interface
ECM	Efficiency Carryover Mechanism
EDD	Effective Degree Days
EI	Economic Insights
ESS	Energy Saving Scheme
FEED	Front End Engineering Design
FSA	Field Services Agreement
GAW	Government Authority Work
GDHI	Gross Household Disposable Income
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
HIA	Housing Industry Association
I&C	Industrial and Commercial
IPART	Independent Pricing and Regulatory Tribunal of NSW
IT	Information Technology
JAM	Jemena Asset Management

JGN	Jemena Gas Networks (NSW) Ltd
MDLs	Meter Data Loggers
MDQ/CD	Maximum Daily Quantity/Chargeable Demand
MRP	Market Risk Premium
NBN	National Broadband Network
NECF	National Energy Customer Framework
NER	National Electricity Rules
NERL	National Energy Retail Law
NGER	National Greenhouse and Energy Reporting
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
OB	Opportunity Brief
PIAC	Public Interest Advocacy Centre
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RoLR	Retailer of Last Resort
RPPs	Revenue and Pricing Principles
RSA	Reference Service Agreement
RY	Regulatory Year
SCC	Stress Corrosion Cracking
SFD	State Final Demand
SGSPAA	SGSP (Australia) Assets Pty Ltd
SLCAPM	Sharpe-Lintner Capital Asset Pricing Model
STTM	Short Term Trading Market
TAB	Tax Asset Base
TPC	Total Planning Costs
TSS	Tariff Structures Statement
WACC	Weighted Average Cost of Capital

OVERVIEW

1. Jemena Gas Networks (**JGN**) delivers a safe, reliable and affordable natural gas service to our 1.3 million residential and business customers across NSW. This is what our customers expect from their gas service, and these expectations have been monitored and met for over 150 years.

2. Our revised proposal offers our customers a continuation of this safe and reliable service for the five-year period commencing 1 July 2015. We are pleased we can also offer to reduce our charges for our residential and small business customers by up to 40 per cent in real terms over the same period.

3. However, the Australian Energy Regulator's (**AER's**) draft decision[1] (**draft decision**) on our 2015-20 access arrangement proposal (**initial proposal**)—if reflected in the AER's final decision—will jeopardise the safe and reliable level of service our customers have told us they value. This is because we would not have sufficient funding to prudently invest in and manage the NSW gas distribution network in the long-term interests of our customers.

4. We consider that many of our concerns with the draft decision are the result of three underlying issues:

   - *NSW energy market changes not appreciated*—the draft decision appears detached from the widely-acknowledged structural changes occurring in the NSW energy market, including the level of competition facing grid-delivered natural gas in NSW and the implications this has for us and our proposal
   - *no customer engagement by the AER*—the draft decision has not benefitted from direct engagement with NSW energy customers, unlike our initial proposal which was founded on a robust customer engagement program
   - *errors of fact and logic*—the draft decision and associated consultant reports contain statements, positions and conclusions unsupported by evidence and without any reference to the requirements of the National Gas Rules (**NGR**) and National Gas Law (**NGL**).

THE NSW ENERGY MARKET IS CHANGING

5. Our initial proposal sought to clearly explain the NSW energy market conditions that shaped the plan for our network from 1 July 2015. These market conditions are characterised by rising wholesale gas prices[2], falling electricity prices[3], competition from non-traditional energy sources[4], gas appliance substitution[5], challenging government policy settings[6] and improving energy efficiency[7].

6. These conditions place JGN squarely in a competitive market environment with other fuels that can power NSW homes and businesses.

7. This environment drives JGN to seek out lowest sustainable cost solutions in delivering the safe and reliable level of service our customers expect for their money. It drives us to market the lifestyle benefits of natural gas

1 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014.

2 JGN, *2015-20 access arrangement information*, 30 June 2014, para 83.

3 Ibid, para 152.

4 Ibid, para 120.

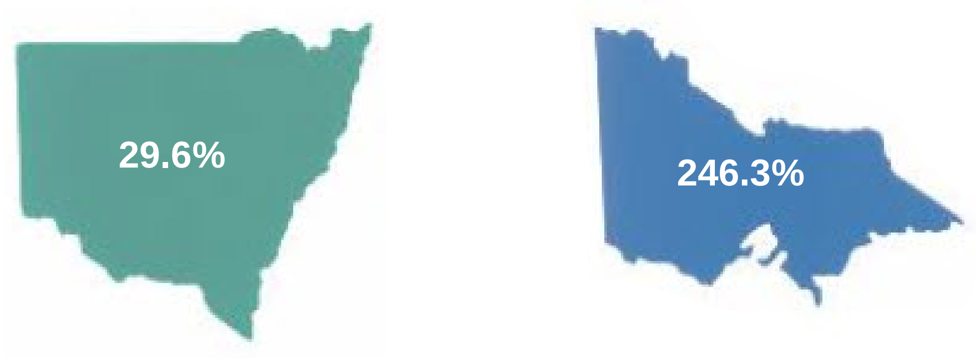
5 Ibid, para 126.

6 Ibid.

7 Ibid.

as a fuel of choice in NSW—residential natural gas consumption in NSW is only a small fraction of total electricity consumption compared to cooler states such as Victoria,[8] as set out in Figure OV–1.

Figure OV–1: Ratio of 2012-13 residential natural gas to electricity (inc. solar) consumption in NSW and Vic



Source: BREE, 2014 Australian energy statistics, July 2014, table F

8. It is not sustainable, and makes no business sense, for us to spend our customers' money carelessly or price our services in a manner that does not promote the efficient use of natural gas. In circumstances where customers are increasingly concerned by their energy bills and have viable energy alternatives increasingly available to them, this only serves to increase the pressure on our business and our customers.

9. Almost all market participants and observers have publicly acknowledged this evolving market paradigm. The competitive environment facing natural gas in NSW has been observed by government bodies, customer groups, industry and media:

- the Public Interest Advocacy Centre (**PIAC**) believes that because gas is a discretionary fuel for many consumers, JGN has had to be more mindful of its consumers and what they want[9]
- the AER's Consumer Challenge Panel (**CCP**) has noted that natural gas is a discretionary fuel, so JGN needs to be proactive to ensure that it remains an attractive fuel option[10]
- Origin Energy agrees that gas is a discretionary fuel of choice in NSW, with increasing fuel options available to households and small businesses for cooking, heating and hot water, and as a result, demand is more sensitive to movements in gas prices and other factors, relative to demand in cooler climates[11]
- retailers more generally have observed to the Australian Energy Market Commission (**AEMC**) that retailers are not going to be in the gas market without being in the electricity market because there are more customers in electricity than in gas, and gas is a fuel of choice rather than an essential energy source like electricity[12]

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8 This was also discussed at meetings with AER staff on 22 July 2013 and 26 September 2013 (refer appendix 1.7).

9 PIAC, *Submission to the AER's review of prices for Jemena Gas Networks from 1 July 2015*, August 2014, p 2.

10 AER Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 7 regarding Jemena Gas Networks (NSW) Access Arrangement 2015-2020 proposal,* September 2014, p 12.

11 Origin Energy, *Submission to Jemena's access arrangement proposal*, August 2014, p 7.

12 Sapere*, Report prepared for the AEMC - Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales - Report of Interviews with Energy Retailers,* February 2013, p 49.

- energy market analysts have observed the “death of the gas bill” and that natural gas “is at a crossroads”[13] as customers look for alternative fuels
- the print media has noted that demand for gas is soft, especially as large industrial users close factories or look to switch to cheaper fuel sources, hence the push to reduce prices to try to protect the competitive position of gas.[14]

10. In light of this recognised reality and our explanation of the NSW gas market environment in our initial proposal and stakeholder submissions, we were particularly troubled by the portrayal of our business in the draft decision. The following extract is contained in the JGN draft decision overview, and is replicated, word-for-word, in the draft decision overviews for the Networks NSW electricity businesses, Transgrid, TasNetworks and ActewAGL electricity networks[15]:

> *…in the energy networks industry the usual competitive disciplines do not operate. The service providers are largely natural monopolies. Many of the products they offer are essential services for most consumers. Consequently, in a non-competitive environment, consumers have little choice but to accept the quality and price service providers offer.*
>
> *The NGL and NGR aim to remedy the absence of competition by empowering us, as regulator, to make decisions that are in the long term interests of consumers.*[16]

11. We feel it is vital that the application of economic regulation to network businesses needs to take into account their individual operating circumstances, market environment and the resulting extent to which workable competition already curtails many of the market power concerns that economic regulation would otherwise seek to address. Failure to recognise this will likely deliver regulatory outcomes that are not fit for purpose and risk increasing the cost of regulatory intervention beyond what is warranted by the market circumstances.

12. The above identical statements across all current AER gas and electricity draft decisions suggest that the AER:

- does not appreciate the important differences between gas and electricity as energy options for NSW customers
- considers that regulated energy businesses make ambit claims not in customers’ interests, and therefore it is incumbent on it, as economic regulator, to always disallow material elements of the business’ proposal.

13. We submit that this traditional regulatory presumption threshold—that some level of costs must always be disallowed—should not apply to JGN. Our business is exposed to the realities of operating in a competitive energy market, particularly for small customers from which over 90 per cent of our revenue is generated. Like our customers, our owners expect the JGN business to be managed at lowest sustainable cost over the long-term. Our owners have invested in network businesses for the long-term and want gas to remain an attractive energy source in NSW.

14. We asked expert economists HoustonKemp to examine the competitive tensions in the NSW energy market, the potential for our customers to switch to an alternative form of energy supply, and the implications of these

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13 Climate Spectator, *Gas death spiral will not help utilities*, 16 December 2014; Grattan Institute, *Gas at the crossroads: Australia’s hard choice*, 19 October 2014. The Melbourne Energy Institute has also noted future uncertainty for gas demand: Melbourne Energy Institute, *The dash from gas. Could demand in New South Wales fall to half?*, January 2015.

14 SMH, *Gas jitters fuel price-cut push*, 30 June 2014.

15 AER, *Ausgrid draft decision – overview*, November 2014, p 17; AER, *Transgrid draft decision – overview*, November 2014, p 15; AER, *TasNetworks draft decision – overview*, November 2014, p 14; AER, *ActewAGL draft decision – overview*, November 2014, p 16. We also note that the overview refers to the National Electricity Objective rather than the National Gas Objective.

16 AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, p 15.

competitive pressures for JGN in providing network services, and the AER in regulating these services. HoustonKemp's report is provided in appendix 1.1. HoustonKemp found that[17]:

- *customers are more aware of the choices they have between energy products and suppliers*
- *technological, market and policy developments have increased the attractiveness of alternative energy sources for space and water heating*
- *the changes in relative prices of electricity and gas are increasing the competitiveness of electricity for many energy consumers.*

15. We feel the AER's presumption threshold when assessing our expenditure and price path proposals needs to reflect these market realities, which differ markedly to those facing electricity networks. HoustonKemp agrees[18]:

> *With JGN facing increased downstream market-driven incentives to be cost efficient, thereby affecting its ability to exercise any market power, the AER should approach its regulatory task differently from that it adopts in relation to electricity networks. In particular, the AER should apply a stronger presumption that the regulatory proposal reflects efficient costs and promotes efficient use of the network. This approach acknowledges that the long-term interests of consumers are best served by minimising the scope for regulatory error, given the risk and so potential costs of JGN reducing service levels, investing unnecessarily or inappropriately raising prices above efficient levels, is likely now to be lower than in the past.*

IMPLICATIONS FOR THE AER'S PRESUMPTION THRESHOLD

16. There is a real risk that a mechanical application of traditional regulatory processes and presumptions by the AER will result in JGN being under-funded. This leaves us with little choice but to underinvest in the network to the long-term detriment of our customers and the long-term viability of our business.

17. In light of the NSW market circumstances we described in our initial proposal, and now again in our revised proposal, and consistent with the Council of Australian Government's Best Practice Regulation Guideline[19], we consider that, before the AER seeks to disallow aspects of our proposal, it should clearly establish a clear evidence-base following extensive consultation with stakeholders, including JGN. As HoustonKemp observe[20], this would involve:

- *acknowledging and explicitly taking into account the incentives for cost and price efficiency arising from increasing opportunities for substitution between gas and electricity by exercising caution in its use of regulatory discretion, so as to minimise the scope for regulatory errors and associated inefficiencies*
- *the AER applying a stronger presumption that the regulatory proposal reflects efficient costs and promotes efficient use of the network.*

18. It must be acknowledged that it is not in our interests to damage the gas brand through either productive, allocative or dynamic inefficiency, for example by:

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17 HoustonKemp, *Implications for JGN of increasing competition in the consumer energy market*, February 2015, p ii.

18 Ibid, p i.

19 COAG, *Best practice regulation – a guide for ministerial councils and national standards setting bodies*, October 2007.

20 Ibid, p 25.

- *overstating our connection unit rates*—new economic connections have always been the foundation of our business' commercial success because they drive lower average network prices and growth in our customer base
- *proposing a price path that works against customers choosing natural gas*—we want a price path that mitigates the impact of wholesale gas price rises on end-retail prices (to support end-retail price stability), which will help gas remain an attractive fuel option in NSW
- *requesting an unreasonable rate of return*—our investors are committed to our assets for the long-term, and expect both fair and sustainable returns from the long-lived assets in which they have invested
- *failing to adapt our tariff offerings for changes in how our customers use gas*—our regulatory asset base (**RAB**) is subject to NGR redundancy provisions[21], so JGN is strongly incentivised to ensure its network price offerings foster innovation in how customers use gas, and the nature of the appliances and generation technologies that they seek to connect to our network.

19. These views could be difficult to accept because they require a different presumption threshold when applying economic regulation to JGN. However, we encourage the AER to step back and consider the incentives that currently face a business in JGN's circumstances before seeking to reject our proposed expenditure, financing costs, tax allowance and price path.

NO CUSTOMER ENGAGEMENT TO INFORM DECISIONS

20. The National Gas Objective (**NGO**) is to promote efficient investment in, and the efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas.

21. The NGO is an important objective to achieve. Fundamentally, it is an economic efficiency objective that requires the optimisation of service attributes and price for the long-term. This requires an appreciation of what the relevant customer-base values by way of service levels and price, and the consequences of trading one for the other(s).

22. This objective and our competitive circumstances place our customers at the centre of our commercial incentives and the regulatory process.

23. The AER established consumer engagement guidelines for network businesses in December 2013. The AER also established a CCP to help it make better regulatory decisions that reflect customers' long-term interests. These are both commendable steps.

24. We welcomed the AER's view that we undertook our pre-lodgement engagement in accordance with its guideline.[22] Comprehensive engagement was fundamental to ensuring our proposal balanced customer preferences for a safe, reliable and affordable service. We undertook robust engagement processes including with:

- the JGN Customer Council, which comprises consumer and industry representatives of residential, small business, large industrial customers, local government representatives and retailers
- residential and small business customers through a series of deliberative forums held in both metropolitan and regional locations
- large industrial customers through one-on-one interviews

[21] NGR rule 85(1).

[22] AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, p 53.

- retailers and other network users as well as other market participants and stakeholders including energy intermediaries through forums and one-on-one discussions
- the Australian Energy Market Operator (**AEMO**), the AEMC, the Independent Pricing and Regulatory Tribunal of NSW (**IPART**) and the NSW Government through one-on-one discussions
- the broader NSW community through the Jemena website and other targeted channels, including distribution of information pamphlets.

25. Since we lodged our initial proposal we have:

- held a public forum on our initial proposal on 15 August 2014, where we fielded questions on our proposal from energy customer advocates, large customers and the Energy and Water Ombudsman of NSW
- responded directly to customer submissions on our initial proposal, including invitations for further engagement if considered helpful
- presented our initial views on the draft decision at the AER's public forum on 8 December 2014
- held three meetings with the JGN Customer Council, two of which involved briefing the Council on the draft decision (16 December 2014) and explaining our revised proposal tariffs and consult on price path options (13 February 2015)
- written to and met with retailers and large customers and discussed a range of matters relevant to our proposal, including price path options.

26. Given that a representative sample of our 1.3 million mass market customers are supportive of our proposed levels of safety and reliability, we feel that it is incumbent on the AER to explain the consequences of its expenditure disallowances on future network safety and reliability, and how these consequences are consistent with our customers' stated preferences.

27. We also consider there are fundamental gaps in the AER's attempts to involve customers in the JGN price review process. As detailed in appendix 1.2, the AER, itself, has not undertaken any meaningful customer engagement as part of the JGN review process. This is despite the AER's commitment, expressed almost two years ago, that it was[23]:

> *seeking to enhance consumer engagement in our processes and improve our decision making under the new rules for network regulation…*

28. Direct AER engagement with customers is particularly important because, as the CCP has previously advised the AER[24]:

> *It makes sense for the regulator to use a number of different means of consumer engagement to assess the consumer interest, so that it can "sense check" specific ideas....it is not likely to be a good idea to create a monopoly provider of the consumer view…*
>
> and
>
> *…the Consumer Challenge Panel is only part of a consumer engagement strategy for the AER, that will also include consultation with consumer organisations and individual consumers and the outcomes of consumer engagement undertaken by the network businesses.*

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23 AER, *AER's Consumer Challenge Panel: description, charter and evaluation criteria*, April 2013, p 1.

24 Dr Gill Owen, *The potential role of the Consumer Challenge Panel in energy network regulation in Australia: a think piece for the Australian Energy Regulator*, 13 March 2013.

29. Despite this AER commitment, and the advice from the CCP, the CCP sub-panel assigned to the JGN proposal has observed that the AER[25]:

- has "leant" on the CCP for customer insights as part of the JGN review
- could have provided clearer explanations of how consumer engagement has influenced the outcome of the draft decision.

30. These observations from the AER's own customer advisors are particularly concerning in light of the AER's publicly stated objectives of making regulatory decisions that clearly set out how it considered stakeholder views, and achieving high levels of stakeholder satisfaction with the quality of its engagement program during regulatory reviews.[26]

31. The AER is required to make decisions in accordance with the rules and exercise judgement to promote the long-term interests of customers. There was an opportunity for the AER to undertake robust customer and stakeholder engagement to support its draft decision in order to confirm that its draft decision on both expenditure allowances and the price path was in customers' long-term interests. We feel that absent such engagement, it is very difficult for the AER to assert that its decision is preferable to JGN's proposal. This is consistent with the AER's own statements on the importance of its engagement with customers[27]:

> *Recent energy policy reforms and review recommendations identified ways for us to engage more productively with energy consumers and businesses. This improvement is vital; a lack of consumer engagement in network pricing decisions makes it difficult for us to assess whether network business proposals reflect the services consumers want.*

32. JGN has gone to considerable lengths and expense to ensure that each time we state customer support for a position, or that customer interests are better served, we have provided probative evidence of that in the form of our engagement feedback and survey results. We expect at least an equivalent level of evidence to support any counter claims.

ERRORS OF FACT, LOGIC AND APPROACH—DRAFT DECISION DOES NOT DELIVER ON THE REVENUE AND PRICING PRINCIPLES OR PROMOTE THE NGO

33. We have difficulties with the proposition that the draft decision reflects proper consideration of the NGO or the revenue and pricing principles (**RPPs**).

34. We think that the NGO is best promoted by determining the best forecasts of the different cost building blocks and demand forecasts. Just as importantly, the determination must give proper consideration to the RPPs.

35. The RPPs reflect a form of regulatory commitment to network businesses that is necessary to underpin continued investment in providing services in the long-term interests of our customers. Three commitments in the RPPs are particularly essential for the achievement of the NGO, namely:

- we should be provided a reasonable opportunity to recover at least the efficient costs we incur in providing service to customers

[25] David Prins, *Jemena Gas Networks public forum presentation*, 8 December 2014. The first observation was made verbally by Mr Prins at the forum.

[26] AER, *AER strategic priorities and work program 2013-14*, p 9.

[27] AER, *AER Annual Report 2013-14*, p 16; See also AER, *AER strategic priorities and work program 2013-14*, p 9.

- our prices should provide for a return commensurate with the regulatory and commercial risks involved in providing services to customers
- regard should be had to the economic costs and risks of the potential for
  - under and over-investment in the gas network
  - under and over-utilisation of our network.

36. It is vital that these principles are met and that the AER ensures each building block component reflects the NGR requirements and contribute to these principles, in achieving the NGO. This view is supported by expert regulatory economist Geoff Swier.[28] Our initial proposal reflected a thorough and balanced building block proposal formulated in consideration of these important principles, in order to best promote the NGO.

37. In our view, the draft decision does not reflect a proper consideration of the RPPs and does not promote the NGO.

38. First, the draft decision contains multiple material errors of fact and logic in assessing the building block components and demand forecast, which means that it will not meet the requirements of the RPPs and will not promote the NGO.

39. Second, the draft decision lacks any real assessment of the whether the decision best promotes the NGO. The draft decision states that[29]:

> *…for the first time, we have specifically assessed our overall revenue decision and its contribution to the achievement of the NGO. We consider this is an appropriate change as we determine an overall revenue allowance… As the overall revenue allowance is the key binding feature of our draft decision, it is important that we specifically assess its contribution to the achievement of the NEO* (sic)*.*

40. This statement presents the AER as taking a holistic approach to its decision-making. It is, of course, critical that the AER consider whether the overall revenue allowance and approved tariffs will allow JGN to recover at least its efficient costs and an appropriate commercial return, as required under the RPPs and to promote the NGO.

41. However, we have not been able to identify any evidence that the draft decision, in fact, reflects a considered assessment of the contribution of the overall revenue decision and approved tariffs to the NGO, beyond mere formulaic assertion.[30] There is no meaningful consideration of whether the overall revenue allowance and approved tariffs will allow JGN to recover at least its efficient costs and an appropriate commercial return as required under the RPPs, and certainly no meaningful consideration of the risks that the decision will result in under-investment in, and under-utilisation of, our network.

42. The only mention of the overall revenue decision is in the overview section, where the AER states:

> *We are satisfied the overall revenue allowance for JGN provides a return sufficient to promote efficient investment, while incentivising JGN to operate its network efficiently.*[31]

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28 G Swier, *Economic considerations for the interpretation of the NGO – expert report for Jemena Gas Networks (NSW) Ltd*, 23 May 2014.

29 AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, p 14.

30 We also note that AER considers that a decision will contribute to the NGO where consumers are provided a "reasonable level of service at the lowest sustainable cost". It is not clear what is meant by "reasonable level of service", including how reasonableness is determined.

31 AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, p 22.

and

Based on our assessment of the building block costs, we determine a total revenue requirement of $2477.3 million ($nominal, smoothed) for JGN over the 2015–20 access arrangement period. We are satisfied that this amount meets the requirement of rule 76 of the NGR.[32]

43. In our view, such statements do not constitute an assessment and they certainly do not reflect any considered assessment.[33]

44. The draft decision overview suggests that the AER considers it can, in some generalised way through the exercise of unclear regulatory judgment, look at a potential range for a final revenue allowance and satisfy itself that it meets the rule requirements and RPP and NGO requirements.

45. The AER's references to the NGO are very formulaic and do not demonstrate any substantive critical assessment or analysis of alternatives and how they better promote the NGO. We think the AER needs to consider the NGO in a more substantive way. We believe the NGO will be promoted by faithfully and objectively applying the building block methodology specified in the NGR in a balanced way, to ensure the RPP requirements are met. To illustrate this point, there is compelling probative evidence that the AER's approach to determining the allowed rate of return will result in a biased low estimate.

46. Critically, we note that the draft decision does not contain any material consideration and analysis of the specific requirements of the RPPs enshrined in the NGL. The draft decision overview simply says that the AER is aware of the consequences of underinvestment for the long-term interests of customers, and it has therefore consistently selected estimates that provide JGN with a reasonable opportunity to recover efficient costs. Beyond this generic statement, there is no evidence of specific consideration of those consequences and the risks of its decision.

47. As a result, it is not clear to JGN that the AER can be confident that its draft decision delivers on the key RPPs and in doing so better promotes the long-term interests of NSW gas consumers relative to our initial and revised proposals, which do not contain these deficiencies.

CONSEQUENCES OF UNDER-FUNDING JGN

48. The AER's draft decision—if made final—would result in a material reduction in our expected revenues over 2015-20. The draft decision does not consider whether this outcome would reflect the RPPs or best promote the NGO. This is despite our 20-year asset strategy[34] clearly setting out the customer outcomes under different expenditure and service scenarios, and our customers telling us directly they were not willing to forgo current service levels for materially lower prices in the short term.[35]

49. Guided by our 20-year asset strategy, we have considered the implications for JGN and our customers if the draft decision revenue outcomes were reflected in the final decision. In that scenario, the final decision would result in materially negative consequences for the long-term interests of customers. For example, we would:

- reduce asset replacement expenditure, reduce or delay non-urgent gas mains repairs and lower short-term maintenance expenditure resulting in the public experiencing an increasing frequency of gas leaks

32 Ibid, p 23.

33 We assume that the draft decision would have included any assessment to provide stakeholders (including JGN) an opportunity to review the assessment.

34 JGN, *2015-20 access arrangement information – appendix 6.1*, 30 June 2014.

35 JGN, *2015-20 access arrangement information – appendix 1.4*, 30 June 2014.

- downsize resourcing for emergency response, increasing response times
- connect fewer new dwellings to our network due to cash constraints, resulting in higher average prices for all existing customers.

50. Clearly there would be a material negative impact on the short and long-term forecast of number of customers connected to the network as result of the AER's position. We would look to unwind these negative outcomes as quickly as practical from 2020, to promote customers' long-term interests. Unfortunately, but necessarily, this would result in a step-up to higher network prices from 2020 for all our customers.

51. A more detailed explanation of the long-term consequences for customers, if the AER's draft decision is made final, is set out in appendix 1.3.

OUR REVISED PROPOSAL

52. Our revised proposal reflects our view of the minimum funding necessary to provide our customers a safe, reliable and affordable gas service now, and into the future. It substantially reflects our initial proposal except for adjustments to account for new circumstances and market data available since our initial proposal was prepared.

OUR SERVICE PROPOSAL

53. Our customers have told us they expect a continuation of the safe and reliable natural gas service we have historically provided. On behalf of our customers, we do not accept the service level outcomes that would result from the draft decision. Consistent with our initial proposal, our revised proposal would allow us to deliver an affordable gas service that is safe and reliable, responsive, supports public amenity and provides a standard level of service to all residential customers.

OUR COST PROPOSAL

54. We need to invest in and maintain our network to deliver the service outcomes that our customers have told us they value. As a result, we do not accept the expenditure allowances reflected in the draft decision. Broadly, our revised expenditure proposals are consistent with our initial proposal, updated for new information and changed circumstances. Our rate of return proposal is lower than our initial proposal, reflecting lower prevailing interest rates relative to when our initial proposal was prepared. In summary we propose, over the 2015-20 AA period (in real $2015):

- gross capex of $1.1B, compared with the draft decision allowance of $942M
- opex of $805M, compared with the draft decision allowance of $780M[36]
- a rate of return of 7.15 per cent p.a., compared with the draft decision allowance of 6.80 per cent p.a.

55. Importantly, we have also not accepted the demand forecasts set out in the draft decision. The draft decision demand forecasts reflect the application of erroneous methods that will not provide us a reasonable opportunity to recover at least our costs. Our revised proposal demand forecasts generally retain the methods adopted in our initial proposal, updated for new available information to ensure they remain the best forecasts in the circumstances.

OUR PRICE PROPOSAL

56. Our price proposal for each customer type is set out in Table OV–1. We have targeted savings to our residential and small business customers, while offering an ongoing small real price increase for our largest business customers (demand market) to return to these customers to cost-reflective network price levels.

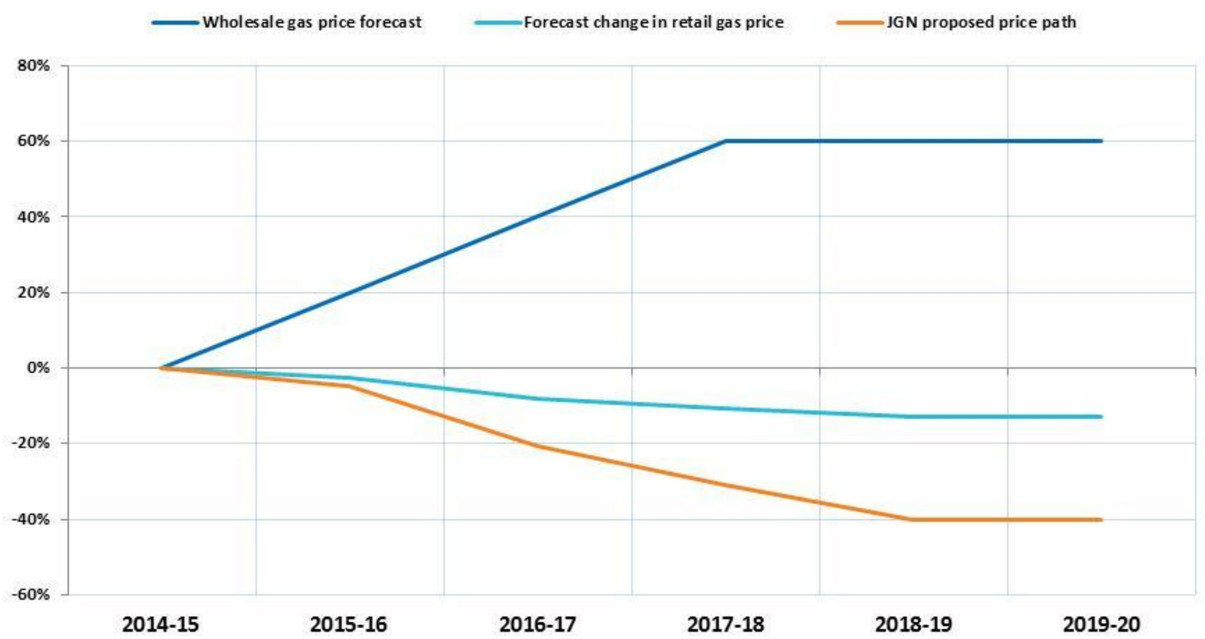
36 Opex excludes debt raising costs.

Table OV–1: Individual customer type network price changes

Customer type	Typical network bill 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Cumulative % total	Total network savings over the period
Small residential (15 GJ pa)	$412	(4.88%)	(16.51%)	(13.16%)	(13.16%)	(0.12%)	(40.18%)	$563
Medium coastal residential (25 GJ pa)	$506	(5.07%)	(14.23%)	(12.62%)	(11.16%)	(0.03%)	(36.80%)	$638
Large coastal/medium country residential (50 GJ pa)	$717	(5.57%)	(11.11%)	(11.50%)	(10.21%)	1.68%	(32.17%)	$809
Small I&C (200 GJ pa)	$2,161	(9.40%)	(5.76%)	(8.82%)	(9.77%)	4.44%	(26.63%)	$2,216
Medium I&C (2000 GJ pa)	$17,927	(11.02%)	(2.69%)	(6.29%)	(7.87%)	5.34%	(21.25%)	$16,099
Large I&C (8000 GJ pa)	$56,787	(12.93%)	0.65%	(6.19%)	(6.49%)	5.16%	(19.15%)	$48,461
Average demand customer	n/a	2.5%	2.5%	2.5%	2.5%	2.5%	13.14%	n/a

57. Figure OV–2 shows that our proposed price path targets our price decreases in years when wholesale price increases are forecast, providing stable end-retail prices for our residential customers.

Figure OV–2: Wholesale, retail, and network price paths for our residential customers



1. INTRODUCTION

1.1 PURPOSE OF THE 2015 AA REVISED SUBMISSION

58. Jemena Gas Networks (NSW) Ltd (ACN 003 004 322) has prepared a revised 2015-20 access arrangement (**AA**) submission (**revised 2015 AA submission**) that responds to Australian Energy Regulator's (**AER**) draft decision on JGN's initial proposal for the NSW natural gas distribution network owned, controlled and operated by JGN for the period 1 July 2015 to 30 June 2020.

59. The revised 2015 AA submission comprises several documents:

- this document, the response to the draft decision[37] (**response to the draft decision**)
- a revised AA proposal (which includes a revised reference service agreement (**RSA**)), that reflect our response to the draft decision
  - detailed explanations of our revised AA and RSA relative to our initial proposal, and for the AA also relative to our 2010AA (provided as appendices 1.4 (AA) and 1.5 (RSA))
- a revised access arrangement information (**AAI**), which provides the information that is reasonably necessary for users and prospective users of the JGN network to understand:
  - the background to the revised AA proposal
  - the basis and derivation of the various elements of the revised AA proposal.

60. This response to the draft decision addresses each element of the draft decision, explains the long-term implications for customers and presents a revised proposal for the AER's consideration. Where appropriate we:

- accept the draft decision where that decision:
  - approves (explicitly or implicitly) sufficient funding to enable us to invest efficiently in, and safely and sustainably manage, the network in the long-term interests of our customers
    - should the AER consider changing its position on any of these issues, we would expect the opportunity to make submissions on these matters before the final decision, in accordance with section 28 of the NGL
  - requires immaterial amendments to our proposal, to allow our response to target issues of particular importance to the promotion of the long-term interests of our customers
- re-frame and/or support the basis for our initial proposal to address the concerns raised by draft decision where we disagree that the draft decision better promotes the long-term interests of our customers.
- update our initial proposal to take into account new circumstances since the initial proposal was prepared and to ensure our proposal forecasts reflect the lowest sustainable cost of delivering safe, reliable and affordable services to our customers from 1 July 2015.

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[37] The response to the draft decision includes all the appendices listed in chapter 13, and the supporting information.

1.2 INTERPRETATION

61. This response to the draft decision adopts the following drafting conventions:

- monetary values are reported in real 2014-15 Australian dollars i.e. ($2015), unless indicated otherwise
- annual values are reported on a 1 July to 30 June regulatory year (**RY**) basis, unless indicated otherwise
- numerical values in tables may not tally due to arithmetic rounding
- reference to a "rule" is a reference to a rule from the NGR
- the document "Access arrangement JGN's NSW gas distribution networks 1 July 2010 – 30 June 2015, amended by order of the Australian Competition Tribunal, 30 June 2011, further amended with regard to mines subsidence expenditure, 26 September 2011, June 2010" is referred to as the **2010 AA**
- the document "Access arrangement information for the access arrangement, JGN's NSW gas distribution networks 1 July 2010 – 1 July 2015, amended by the order of the Australian Competition Tribunal, 30 June 2011, further amended with regard to mine subsidence expenditure, 26 September 2011, June 2010" is referred to as the **2010 AAI**
- the document "Jemena Gas Networks, 2015-20 Access Arrangement Information, 30 June 2014" is referred to as the **initial proposal**
- the document "Jemena Gas Networks, Access Arrangement, JGN's NSW gas distribution networks, 1 July 2015 – 30 June 2020, 30 June 2014" is referred to as the **initial AA proposal**
- the document "AER, Draft decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20, November 2014" is referred to as the **draft decision**
- references to the '2010-15 AA period' or 'current AA period' refer to the period commencing 1 July 2010 and ending 30 June 2015
- references to the '2015-20 AA period' or 'next AA period' refer to the period commencing 1 July 2015 and ending 30 June 2020.

62. An abbreviations list is also provided in this response to the draft decision. Our confidentiality claim is provided as appendix 1.6. We have also provided a set of pre-lodgement engagement materials as appendix 1.7. These materials provide evidence of our engagement with stakeholders and the AER.

2. PIPELINE SERVICES

Box 2–1 Key messages – pipeline services

With new alternative energy sources becoming increasingly attractive, and the expected doubling of the wholesale gas price, we expect customers to closely review their energy bills to ensure they are continuing to receive a value for money gas service.

To facilitate such assessments, it is important that we do what we can to simplify gas pricing arrangements where appropriate. This will ultimately support allocative efficiency because customers will make more efficient gas consumption choices.

We think that bundling our haulage, meter and meter data services into a single reference service will help streamline network pricing arrangements over the next 5 years. It will facilitate retail market participation and customer choice. There are no material negative customer impacts, recognising that this decision can be revisited in five years' time, if required.

Most importantly, this is what our customers have told us they want, and we therefore welcome the draft decision's acceptance of our proposal in this regard.

2.1 AER DRAFT DECISION

63. The draft decision approved JGN's services proposal.[38] As noted by the AER[39]:

- the market to implement gas meter reading contestability in NSW has not changed since 2000 and there is no evidence that it may change in the next AA period
- the provisions to facilitate contestable meter data services were removed from NSW and ACT gas retail market procedures in 2000
- the existing approved RSA requires that services be taken as a bundled service
- there is no gas network or retail cost imperative for time of use pricing and associated customer behavioural change
- our consumer engagement identified the aggregation of pipeline services as a way to simplify small customer bills and better facilitate effective customer participation in the retail gas market.

64. We note that the draft decision states:

> *…if retailers can provide to us compelling reasons not to merge metering data services into a single reference service, we may review our draft decision position when making the final determination.*[40]

[38] AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 1-7.

[39] Ibid, p 1-9.

[40] Ibid, p 1-10.

2.2 JGN RESPONSE TO THE DRAFT DECISION

65. JGN accepts the AER's draft decision. JGN agrees with the AER decision-making factors and considers they provide a strong basis for accepting JGN's proposal in favour of avoiding unnecessary complexity in network services and tariffs.

66. As distribution charges make up 50 per cent of a residential gas bill, it is important that customers are able to transparently and efficiently assess our network charges that, in combination with JGN's published tariff structures statement (**TSS**), facilitates customers' ability to make longer-term energy usage and appliance investment choices.

67. With new alternative energy sources becoming increasingly attractive, and the expected doubling of the wholesale gas price, we expect customers to closely review their retail energy bills and retailer offers in the competitive retailer market, to ensure they are continuing to receive a value for money gas service. Our proposal assists customers to compare retail offers that include a pass through of network changes.

68. We are unaware of any credible desire for NSW gas metering contestability. We have undertaken another review of publicly available information regarding NSW gas metering contestability and are unable to identify any evidence of such a trend. We would expect that any trend would be limited to cooler states such as Victoria, where gas bills are more driven by heating load, which is more controllable than cooking and hot water loads.

69. If such a trend was to arise in NSW, our service offerings would be reconsidered in consultation with stakeholders when we propose a revised AA in 2019. We note that a necessary precondition for NSW gas metering contestability would be to introduce provisions to facilitate contestable meter data services into the NSW gas retail market procedures. The prescribed process[41] for amending these procedures involves significant stakeholder engagement requirements, including mandatory consultative forums and potentially specialist working groups, and impact and implementation reports. JGN therefore considers that all stakeholders would have ample time to prepare for any resulting amendments to JGN's AA in 2019, should this eventuate.

70. Should the AER receive any further relevant evidence from retailers on this issue, we would expect the opportunity to review and make submissions on the evidence prior to the AER's final decision, in accordance with section 28 of the NGL.

41 Rule 135EC of the NGR.

3. DEMAND

Box 3–1 Key messages – demand

The demand forecasts are a key input into the capex and opex forecasts for the next AA period, and are used to calculate prices from the AER's overall revenue allowance. Establishing the best, reasonably-based demand forecasts in the circumstances is critical to afford JGN a reasonable opportunity to recover at least its efficient costs and thereby supports our ability to deliver the safe and reliable gas service our customers expect.

JGN's demand forecasts have been prepared by Core Energy, an expert in energy demand forecasting. The AER's demand forecasting consultant, Deloitte Access Economics (**DAE**), found Core Energy's demand forecasts to be transparent, clear and generally sound in terms of methodology.[42] Nonetheless, the AER rejected these demand forecasts.

We believe the AER's rejection was based on clear and material errors of fact, analysis and reasoning.

The AER rejected Core Energy's gas consumption forecasts for tariff V residential and I&C customers based on the incorrect finding that these forecasts underestimated forecast per customer consumption because they did not include a separate allowance for economic activity as a driver of per customer consumption. This finding is factually wrong. To include a separate allowance for economic activity, it must be demonstrated that economic activity is a driver of per customer consumption for these customers, and that economic activity is also forecast to be materially different relative to the historical period. However, there is no statistically reliable evidence that economic activity is a relevant driver of gas consumption for these customers and there is no evidence that DAE's selected economic activity parameters will be different over the forecast period compared to the historical period. Therefore, the AER's finding that Core Energy's methodology is likely to underestimate forecast per customer consumption is in error.

In rejecting Core Energy's forecasts, the AER adopted annual changes in forecast per customer consumption for tariff V residential and I&C customers based on "desktop"[43] regression modelling by DAE and applied those changes within Core Energy's forecasting models.

JGN has re-engaged Core Energy to review the AER's draft decision and update the demand forecasts for current information. JGN also engaged demand forecasting and econometrics experts HoustonKemp and Frontier Economics to review DAE's methods and forecasts for tariff V customers.

The three experts have found that DAE's forecasting methods are flawed and do not produce reasonable tariff V residential and I&C per customer consumption forecasts, including because DAE's regression models contain data selection errors and DAE have used a model specification which is statistically biased, unstable and produces spurious results.

Further, these experts have found that DAE applied the results of their regression models for tariff V residential and I&C per customer consumption forecasts to prepare forecasts which are materially higher than the forecast results derived from DAE's actual regression models. In fact, the results of the DAE models (if they were to be relied on) are closer to Core Energy's forecasts.

The AER also relied on other selective and flawed forecast assumptions from DAE and adopted the erroneous DAE forecasts, resulting in substantial increases in estimated annual per customer consumption for tariff V residential and I&C customers. As a result, the AER draft decision approved prices fall substantially below those required to allow JGN a reasonable opportunity to recover at least its efficient costs. The effect of the AER's application of the

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[42] DAE, *Australian Energy Regulator, Review of Core Energy Group gas demand forecast for Jemena's NSW network*, 11 August 2014, p ii (**DAE Report, August 2014**); DAE, *Australian Energy Regulator – Gas demand forecast for Jemena's NSW network*, 24 November 2014, p 7 (**DAE Report, November 2014**).

[43] DAE Report, November 2014, p 7.

erroneous DAE forecasts is that JGN expects to under-recover revenues by approximately $90 million relative to the amount required to cover its efficient costs over the next AA period.

Accordingly, JGN does not consider that the AER's substituted demand forecasts are reasonable or the best estimates in the circumstances. Core Energy's demand forecasts are both reasonably-based and the best in the circumstances, in accordance with the requirements of rule 74(2). When used in deriving prices and expenditure forecasts, Core Energy's forecasts afford JGN a reasonable opportunity to recover at least its efficient costs as required under the RPPs.

3.1 REQUIREMENTS OF THE RULES

71. The NGR requires an AA to include a forecast of pipeline utilisation (which has been driven by gas consumption) over the next AA period and the basis on which the forecast has been derived.[44] Under rule 74(2), all forecasts and estimates must be arrived at on a reasonable basis and must represent the best forecast estimate possible in the circumstances.

72. The demand forecasts, comprising forecasts of per customer consumption and connections for each customer segment, are critical inputs into:

- opex and capex forecasts used in determining the overall revenue allowance[45]
- the derivation of network tariffs, where tariffs (in simple terms) are set as a function of allowed revenue divided by forecast demand.

73. Establishing the best demand forecasts possible in the circumstances is critical because if the demand forecasts are affected by errors they will:

- *result in either over or underestimates of forecast capex and opex*—consequentially, capex and opex forecasts will also not satisfy r 74(2)
- *not provide JGN a reasonable opportunity to recover at least its efficient costs*—it is a fundamental requirement under the RPPs in s 24(2) of the NGL that JGN is afforded a reasonable opportunity to recover at least the efficient costs incurred in providing reference services.

3.2 JGN'S APPROACH TO FORECASTING DEMAND—USE OF THE ROBUST CORE ENERGY TREND APPROACH

74. JGN's demand forecasts were prepared by Core Energy Group Pty Ltd (**Core Energy**).

[44] Rule 72(1)(d) provides that to the extent that it is practicable that the access arrangement information must include a forecast of pipeline capacity and utilisation of pipeline capacity over the access arrangement period and the basis on which the forecast has been derived.

[45] For example: (i) the market expansion capex forecast reflects the forecast of new connections to the network and the forecast efficient unit rate for those connections; (ii) the trend escalation component of the opex forecast subject to the base, step, trend method reflects, in part, new connections to the network; (iii) the UAG component of the opex forecast is forecast as the product of the forecast total volume of gas consumption, the UAG target rate and the forecast wholesale gas price.

75. Core Energy is an expert in demand forecasting with extensive experience in developing advanced, fit-for-purpose models and simulation systems to facilitate comprehensive analyses of electricity and gas demand and supply. Core Energy has completed energy demand forecasts for every jurisdiction in Australia.[46]

76. Core Energy's approach for JGN is broadly consistent with the approach approved by the AER for Envestra's South Australian, Queensland and Victorian networks, including the approach to weather normalisation.[47] The approach involves forecasting connections and average per customer consumption to provide total forecast demand.

77. In preparing forecasts, Core Energy splits JGN's customer base into four customer segments to reflect the *a priori* expectation that different drivers will influence demand in each segment. The four segments are:

- *tariff V residential*—residential customers consuming less than 10TJ p.a.
- *tariff V small business*—small business customers consuming less than 10TJ p.a.
- *tariff V I&C*—industrial and commercial (**I&C**) customers consuming less than 10TJ p.a.
- *tariff D*—I&C customers consuming more than 10TJ p.a.

78. Table 3–1 sets out the nature of the forecasts that Core Energy has prepared for each of its customer segments, which reflect the manner by which each customer group is billed.

Table 3–1: Nature of Core Energy forecasts

	Customer numbers	Consumption	Maximum Daily Quantity (MDQ)
Tariff V (all three)	Yes	Yes	Not required
Tariff D	Yes	Yes	Yes

79. The methodology applied by Core Energy for each tariff V customer segment involves a balance of both "bottom up" and "top down" steps, namely:

- *step 1*—normalise historic consumption data to remove the influence of abnormal variations caused by weather effects. The normalised consumption is extrapolated to form the base starting point for the consumption forecast
- *step 2*—identify material factors that influence changes in consumption per connection for each customer segment, and collect data to support forecasts of consumption per connection
- *step 3*—identify material factors that influence changes in the net change in connections (i.e. new connections minus disconnections) for each customer segment, and collect data to support forecasts of net connections
- *step 4*—select a preferred methodology for quantifying all material factors affecting per customer consumption and net connections

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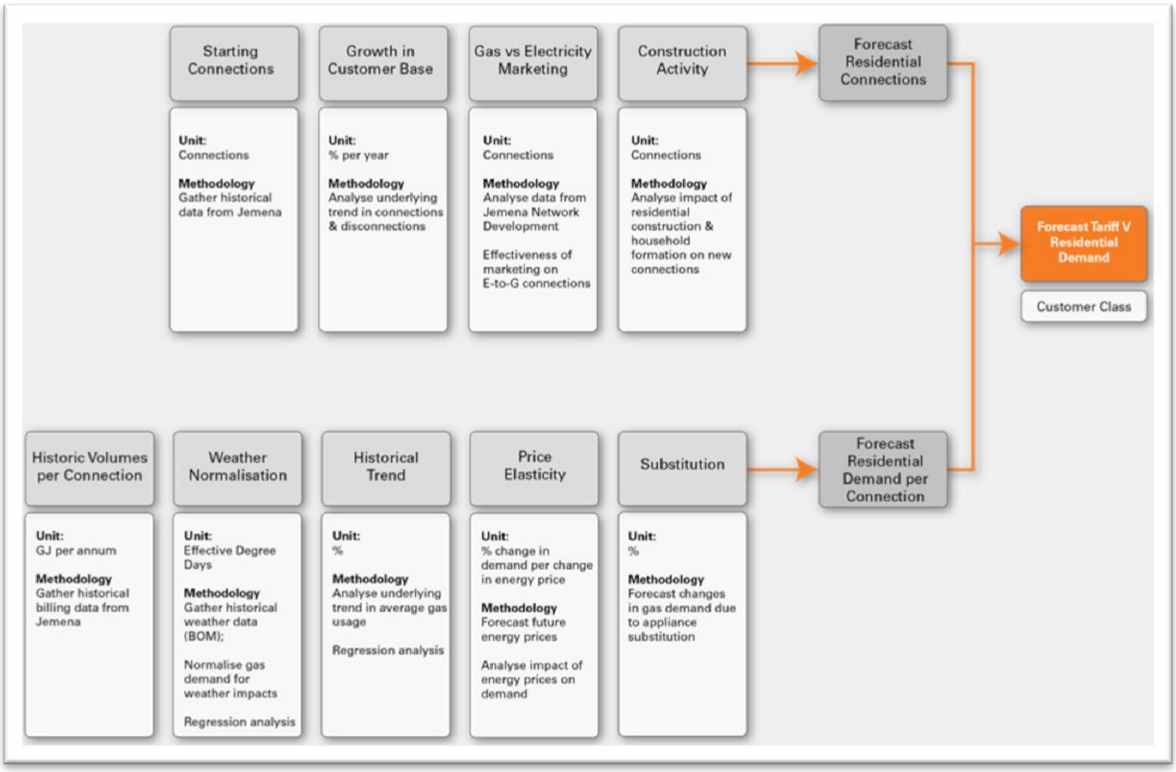
46 Core Energy Group, *Jemena Gas (NSW) Ltd Access Arrangement – Response to AER Draft Decision – Gas Demand Forecast, Core Energy Expert Report*, February 2015 (**Core Energy Report in response to AER Draft Decision, February 2015**), p 13.

47 See e.g., AER, Access arrangement final decision – Envestra Limited 2013-17, March 2013.

- *step 5*—adjust extrapolated gas consumption based on quantified material factors affecting per customer consumption and net connections
- *step 6*—review and validate results based on literature and discussions with JGN.

80. Figure 3–1 provides a summary of Core Energy's approach to forecasting demand for tariff V customers (using tariff V residential customers as an example). For tariff V customers, Core Energy uses a 'historical trend' approach which relies on relevant drivers of consumption to be reflected in forecast consumption outcomes, with any expected "step changes" to these drivers being reflected as out-of-trend adjustments.[48]

Figure 3–1: Core Energy – demand forecasting approach – tariff V residential



3.2.1 APPROACH TO FORECASTING PER CUSTOMER CONSUMPTION

81. Core Energy's approach to forecasting per customer consumption for each tariff segment involves:

- normalising total demand per annum for the effects of weather
- dividing total demand by the number of connections to determine per customer consumption
- determining the historical trend in per customer consumption to establish a base for projection
- adjusting per customer consumption forecasts for factors which are not present in the historical trend.

[48] Core Energy Group, *Gas Demand and Customer Forecasts, Jemena Gas Networks – NSW Gas Access Arrangement 2015-20*, Final Draft, April 2014, p 21 (**Core Energy Report, April 2014**).

82. Core Energy determined that an approach which analyses the historical trend and adjusts it for the impact of each material factor which is reasonably expected to influence per customer consumption and deviate from the historic trend to be the best available approach in the circumstances.[49] This approach is consistent with the approach proposed by Envestra and accepted by the AER.[50]

83. The key features of Core Energy's approach to forecasting per customer consumption are summarised below.

3.2.1.1 Weather normalisation

84. Gas demand is significantly influenced by the effects of weather. Specifically, the need to adjust historical data on gas consumption to take account of variations in weather has been noted by the AEMO.[51]

85. Accordingly, weather influences must be isolated to arrive at normalised consumption to provide a consistent basis for forecasting purposes.

86. Core Energy weather normalised the historical gas consumption data using Effective Degree Days (**EDD**), where cooler temperatures below a given threshold, result in higher gas use for heating purposes.[52] The EDD approach is preferred by AEMO because it not only takes into account the effects of temperature data, but also other relevant factors—such as wind velocity, sunshine hours and seasonal variations in consumer propensity to consume gas.

3.2.1.2 Use of historic trend and evaluation of key forecast drivers

87. Core Energy's approach to forecasting involves an analysis of the historical trend, adjusting for the impact of each material factor which is reasonably expected to influence per customer consumption.

88. The advantage of a trend approach to forecasting per customer consumption is that it is logical, simple and transparent. It assumes the historic trend will continue into the future and adjusts this trend to account only for deviating or "out-of-trend" factors that are material and can be robustly established to influence per customer consumption—through both economic theory and evidence. It also avoids the pitfalls of more complex statistical techniques which can often only rely on a limited set of parameters, and when aggregated, those parameters may not produce outcomes representative of commercial reality.[53] In summary, Core Energy's approach takes into account all relevant drivers of consumption in the trend, which cannot feasibly be taken into account in a multi-variable regression approach.

89. In identifying relevant 'out-of-trend' factors that may alter the extrapolated historic trend in per customer consumption, Core Energy considered a wide range of information, views and data regarding the outlook for gas demand in NSW.[54] Core Energy developed a list of variables which may have the potential to materially influence forecast per customer consumption for each tariff segment.

90. Specifically, Core Energy considered:

- *for connections*—population data, household density and stock data, construction trends

49 Core Energy Report, April 2014, p 22.

50 AER, *Access arrangement final decision – Envestra Limited 2013-17*, March 2013.

51 AEMO, *2012 Review of Weather Standards for Gas Forecasting*, April 2012.

52 Core Energy Report, April 2014, pp 19-20.

53 Core Energy Report in response to AER Draft Decision, February 2015, p 12.

54 Core Energy Report, April 2014, p 62.

- *for per customer consumption*—energy efficiency, appliance trends, dwelling type, forecast retail energy prices and energy substitution.

91. Importantly, the approach used by Core Energy captures all relevant influences on forecast per customer consumption within the historic trend. Specifically, the historic trend will capture characteristics which may have influenced changes in consumption over time, but cannot be directly used in quantifiable terms—for example, the historic trend will capture economic activity relevant to the gas industry, trends in appliance use, substitution and efficiency gains, as well as government energy policies affecting gas demand.[55]

92. This means that it is only anticipated material changes to the factors that influence per customer consumption in the future that need to be accounted for via adjustments to the forecast trend. As explained further below, Core applied empirical data testing to determine whether 'out-of-trend' adjustments for key drivers were required and were quantifiable on a reasonable basis.

93. In summary, Core Energy's approach takes account of relevant drivers of gas consumption per connection which exist within the historic trend, combined with explicit modification for anticipated changes in those same consumption drivers which deviate materially from the extrapolated trend. Core Energy considered this to be a preferable approach, in circumstances where a range of factors influence consumption, but where there may be a weak empirical basis to determine the relationships of each of these factors.

3.2.1.3 Price elasticities

94. In economic theory, the price and price of substitutes are considered to be important determinants of consumption of goods or services. In this case, projected retail gas and electricity prices impact on forecast gas consumption.

95. Core Energy identified that expected movements in retail energy prices in NSW over the next AA period are sufficiently material to warrant step changes from the historical trend.

96. Specifically, Core Energy determined the following factors as reasonably likely to affect the historical trend for per customer consumption:

- *increase in the price of retail gas*—leading to additional declines in gas demand (own-price elasticity response); and
- *decreases in the price of energy substitutes*—specifically grid-delivered electricity, leading to additional declines in gas demand (cross-price elasticity response).

97. To capture the declines in per customer gas consumption as a result of: increases in gas prices, Core Energy captured long-term own-price elasticity through factors of -0.3 for residential customers and -0.35 for non-residential customers. Core Energy's estimates of own-price elasticity are consistent with the estimates adopted and approved in the AER's decision for Envestra (Victoria).[56]

98. To capture the declines in per customer consumption as a result of decreases in retail electricity prices relative to gas prices, Core Energy adopted a long-term cross-price elasticity of 0.1 for residential customers and non-residential customers. Core Energy's extensive international literature studies indicated that 0.1 was a conservative estimate.

99. While the AER has not considered this substitution effect previously, Core Energy considered that material increases in retail gas prices relative to electricity prices and increasing fuel choice will impact NSW customers' decisions in the:

[55] Core Energy Report, April 2014, p 34.

[56] Core Energy Report, April 2014, pp 88-89.

- *short term*—particularly given the high penetration of reverse cycle air-conditioning in NSW that provides customers with heating choice
- *longer term*—as customers make appliance replacement decisions, such as the choice of hot water heaters.

100. Accordingly, DAE and the AER accepted that cross-price elasticity was reasonable to include in the particular circumstances.[57]

3.2.1.4 Consideration of other potentially relevant drivers

101. As noted above, in determining relevant drivers for changes in forecast per customer consumption, Core Energy considered a wide range of information, views and data regarding the outlook for gas demand in NSW. Most relevantly, a standard element of the Core Energy forecasting approach was to consider the relationship between economic aggregate measures such as Gross State Product (**GSP**) and per customer consumption.[58]

102. Core Energy undertook a series of regression analyses to assess whether an economic activity parameter such as GSP should be included as an explanatory variable for tariff V per customer consumption forecasting. However, Core Energy found that the relationship between such parameters and per customer consumption was not statistically significant and therefore was excluded from further consideration as a meaningful variable.[59]

103. At this time, Core Energy also completed an analysis of the relationship between a broader range of variables including, but not limited to: appliance mix trends, energy policy, appliance and dwelling efficiency, and price impact.[60]

104. In Core Energy's opinion a range of factors influence per customer consumption but there was insufficient information to arrive at reliable conclusions as to the statistical significance of each variable. This is the advantage of the trend approach adopted by Core—whereas the reliability of a multi-variable regression approach will depend on the statistical significance and predictive value of its parameters, a historic trend approach overcomes such data limitations. This is because each of the relevant drivers of demand (whether that includes NSW economic activity, or not) will be incorporated in the historic trend.[61]

105. In the Victorian access arrangement for Envestra, Core Energy did use a relationship of gross household disposable income (**GDHI**) as an explanatory variable to forecast residential consumption per connection in Victoria (and GSP for business consumption per connection). In those circumstances Core Energy observed statistically significant relationships, which were not observable in similar analysis undertaken in forecasting consumption for JGN's NSW network.[62] The difference in statistical significance of the economic activity driver on gas consumption between the jurisdictions could be explained by a number of factors—for example, a materially higher penetration rate of gas in Victoria, a materially different climate, and gas consumption per connection in Victoria, which is significantly higher than in NSW.[63]

106. JGN also notes the NSW Government's policy announcement to expand the NSW Energy Saving Scheme (**ESS**) to cover gas and create a further financial incentive for gas efficiency from January 2016 (refer appendix

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57 DAE Report, November 2014, p 29.

58 Core Energy Report in response to AER Draft Decision, February 2015, p 13.

59 Core Energy Group, Response to Deloitte Report, August 2014, section 4.1.1.

60 Core Energy Report in response to AER Draft Decision, February 2015, p 14.

61 Core Energy, Response to Deloitte Report, August 2014, p 8.

62 Core Energy Report in response to AER Draft Decision, February 2015, p 14.

63 Core Energy Report, August 2014, p 7.

3.6). This will be given effect through an increase in ESS targets, and the introduction of a new conversion factor in the "ESS Rule" to enable gas savings activities to generate energy savings certificates. While it is clear that the outcome of the ESS amendments will be further downward pressure on gas demand, Core Energy has not sought to account for this additional 'out-of-trend' factor given the limitations in quantifying the impact without further detail on the legislative amendments. Rather Core Energy has focused on key 'out-of-trend' factors that are quantifiable and can be validated by independent third party analysis.

3.2.2 APPROACH TO FORECASTING CONNECTIONS

107. Core Energy undertook a similar "bottom up" approach to forecasting tariff V connections by customer segment and within the tariff V residential customer segment, for different dwelling categories.[64] Specifically, Core Energy's approach to forecasting customer connections involves:

- using regression analysis to determine the historical trend in new connections to derive a suitable forecast for each year
- analysing the historical trend in the rate of disconnections to derive a suitable forecast for each year
- adjusting connection forecasts for factors which are not present in the historical trend, including forecast changes in the relative prices of gas and electricity.

108. Relevantly, Core Energy determined a step change from the historical trend based on a time series from 2002 to 2013 in relation to the dwelling mix for new connections. Specifically, through third-party analysis and validation testing, Core Energy determined that there would be an increase in the weighting of new, lower gas usage dwellings (i.e. new medium/high density, rather than new estates), as a result of a clear trend towards inner-city living and a higher density dwelling mix—resulting in an allocation split of 48 per cent and 52 per cent for medium/high density dwellings and new estates, respectively.[65]

3.2.3 CONCLUSION: CORE ENERGY METHODOLOGY: TRANSPARENT, CLEAR AND SOUND

109. In summary, Core Energy's forecasting methodology can be characterised as principally a "bottom up" approach—forecasts are developed for each customer segment by modifying the historic trend in per customer consumption for any material "out-of-trend" change that will influence per customer consumption and net connections. Core Energy uses a "top down" approach to validate results using rigorous data testing and third party analysis.

110. Specifically, Core Energy's trend approach to estimating tariff V forecast demand over the next AA period represents a simple, transparent, and well-accepted methodology. As concluded by DAE, "the approach adopted by Core was transparent, clear and generally sound in terms of methodology".

111. JGN notes that the Core Energy trend (or time series) methodology was accepted by DAE and used by the AER for tariff V small business customers.[66]

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64 For residential, these dwelling categories include: existing connections, E-to-G, new estates, new medium density/high rise.

65 Core Energy Report, April 2014, p 58.

66 "*For tariff V small business per customer consumption Deloitte advised that 'the strength of the downward trend over the historical period was larger than the effect of any potential explanatory variables (including price and economic conditions)". For this reason it did not modify Core Energy's trend based forecast method. Core Energy forecast tariff V small business consumption per customer on the basis of the historical trend between 2002 and 2013*": AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, Attachment 13, p 13-13 (**AER Draft Decision, Attachment 13 – Demand**).

3.3 AER DRAFT DECISION

112. The AER engaged DAE to advise on JGN's demand forecasts, and in particular Core Energy's methodology, and to assist it in developing alternative demand forecasts. DAE advised the AER that Core Energy's approach was "transparent, clear and generally sound in terms of methodology".[67]

113. DAE agreed with JGN's proposed tariff D demand forecasts, and they were accepted by the AER. However, DAE did not agree with Core Energy's approach to forecasting tariff V demand and prepared alternative regression models for forecasting. Specifically, the AER adopted annual changes in forecast per customer consumption for tariff V residential and tariff V I&C customers, derived from the results of a "desktop"[68] review by DAE, and provided alternative estimates, on the following bases:

- DAE challenged the non-inclusion of a variable to capture future economic activity (for example, State Final Demand (**SFD**) or GSP) for tariff V residential and tariff V I&C customers.[69]

  Therefore, DAE derived an economic regression model which included SFD and GSP variables for tariff V residential and I&C customers respectively, incorporating own-price elasticity within the model. [70]

- DAE challenged the calculation of the historical trend in per customer consumption for the tariff V small business segment based on 2002-2013 data, having regard to an apparent step change in the data from 2008.[71] Therefore, DAE used a 2008-2013 time period.[72]

- DAE challenged the estimate of an electricity/gas cross-price elasticity estimate of 0.1.[73] Instead, DAE applied a reduced cross-price elasticity of 0.05.[74]

114. DAE also raised issues with JGN's tariff V forecasts for connections on the following bases:

- DAE challenged the dwelling split for new estates and medium/high density connections.[75] DAE applied a different dwelling split based on alternative data.[76]

- DAE challenged the use of the 2002-2013 time period for estimating the historical trend for small business connections, having regard to an apparent step change in the data from 2008.[77] Instead, DAE used a 2008-2013 time period.[78]

- DAE also challenged the use of 2002-2013 time period for estimating the historical trend for residential disconnections.[79] Instead, DAE used a 2011-2013 time period.[80]

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67 DAE Report, August 2014, p ii; DAE Report, November 2014, p 7.

68 DAE Report, November 2014, p 7.

69 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-12, 13-13.

70 DAE Report, November 2014, pp 11-12.

71 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-17.

72 DAE Report, November 2014, pp 17-18.

73 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-13, 13-14.

74 DAE Report, November 2014, pp 28-29.

75 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-15, 13-16.

76 DAE Report, November 2014, pp 14, 16.

77 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-16, 13-17.

78 DAE Report, November 2014, pp 17, 18.

115. The application of DAE's tariff V forecasting method results in increases to forecast annual per customer consumption of:[81]

- up to 8 per cent for tariff V residential customers
- up to 6 per cent for tariff V small business customers
- up to 17 per cent for tariff V I&C customers.

116. When these higher demand forecasts are applied in deriving final approved prices, the expected revenue differential over the next AA period is approximately $90 million.

117. The AER has appeared to accept DAE's revised estimates of tariff V demand without any apparent critical assessment of DAE's conclusions and results. Based on DAE's report, the AER did not accept JGN's proposed demand forecasts. Specifically, the AER's reasons for rejecting JGN's demand forecasts were summarised as follows:[82]

> *In particular, in forecasting demand Core Energy:*
>
> - *Did not include a variable to capture future economic activity, for example, GSP or SFD in its forecasts. As discussed below, economic activity is expected to increase over the next access arrangement compared with the current access arrangement. As a result, the absence of such a variable in Core Energy's forecasts means they are likely to under estimate per customer consumption. On the basis of Deloitte's advice, we have included GSP or SFD in our per customer consumption forecasts for tariff V residential and I&C customers. Deloitte estimated "own price elasticity" within the model. This resulted in different own price elasticities (the sensitivity of gas consumption per customer to changes in the gas price) being applied to tariff V residential and I&C per customer consumption forecasts compared to those applied by Core Energy.*
> - *Calculated a trend in per customer consumption over 2002 to 2013, which was then applied to forecast tariff V small business per customer consumption. As we consider there has been a structural change since 2008 in small business per customer consumption use, we have estimated the trend using 2008 to 2013 data.*
> - *Applied a cross price elasticity (the sensitivity of gas consumption per customer to changes in electricity prices) of 0.1. On the basis of advice from Deloitte, we have reduced this to 0.05.*
> - *Included the carbon price in its forecasts. We have removed the carbon price given the repeal of the carbon tax.*
>
> *In forecasting connections:*
>
> - *we were not satisfied that Core Energy's assumption that 48 per cent of new dwellings are new estate connections and 52 per cent are medium/high density connections was arrived at on a reasonable basis. Based on historical HIA data, we consider that a 44 and 56 per cent*

79 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-11, 13-17.

80 DAE Report, November 2014, pp 19-21.

81 AER Draft Decision, Attachment 13 – Demand, p 13-7. There was no change for tariff D I&C customers.

82 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-11.

allocation respectively for new estate and medium/high density connections produces a better estimate in the circumstances.

- *we consider that Core Energy's forecast of business connections results in an overstated number of connections. This is due to the inclusion of data from 2003 to 2007 in estimating the historical trend which is projected forward. As discussed in greater detail below, we consider that this data should be excluded due to a structural break in the series in 2008, where there was a significant step change in the number of connections. We consider that a trend calculated using 2008 to 2013 data produces the best estimate in the circumstances.*

- *we consider that Core Energy's forecasts of the number of residential disconnections are overstated. This is due to the inclusion of 2002 to 2010 data in estimating the historical trend in the disconnection rate. In contrast to the 2002 to 2010 period, for the three years, 2011 to 2013, the number of disconnections has been stable. Therefore, we are not satisfied that using an increasing trend over this period is appropriate. Rather, we consider that 2011-13 data provides a more reasonable basis for forecasting disconnections than the trend over the 2002-13 period.*

118. As discussed in section 3.4 below, the AER's reasons for rejecting Core Energy's forecasts are based on clear and material errors. Critically, as observed in section 3.5, the AER then go on to adopt forecast per customer consumption estimates provided by DAE which are based on regression models with spuriously specified parameters and containing data selection and other modelling errors that make the outputs from those models unreasonable and unreliable.[83]

119. For completeness, we note that the AER did not adjust Core Energy's initial forecast of tariff V small business per customer consumption in the same manner, and accepted Core Energy's trend approach notwithstanding that it did not include any separate economic activity adjustment.[84]

120. JGN estimates that, because of the AER's error in approving the DAE forecasting method, it should expect to under-recover revenues by approximately $90 million over the next AA period, relative to the AER's revenue allowance.

3.4 AER ERRORS IN REJECTING CORE ENERGY FORECASTS

3.4.1 OVERVIEW

121. The AER did not approve JGN's proposed gas consumption forecasts for tariff V customers. Specifically, the AER was "not satisfied that elements of JGN's forecasting methodology, some of the assumptions applied, and some of the data used, are arrived at on a reasonable basis and represent the best estimate possible in the circumstances".[85]

[83] Notably, for small business gas consumption per connection, DAE applied the same methodology as for the other tariff V customer segments. DAE advised that "the strength of the downward trend over the historical period was larger than the effect of any potential explanatory variables (including price and economic conditions)". For this reason it did not modify Core Energy's trend based forecast method. It found that the historic trend differed from that implied by the econometric modelling, and so concluded that, "… the structural econometric equation for this customer group did not produce reliable and robust results". DAE chose to forecast small business gas consumption per connection applying the same methodology as used by Core Energy: DAE Report, November 2014, p 27.

[84] Core Energy forecast tariff V small business consumption per customer on the basis of the historical trend between 2002 and 2013: AER Draft Decision, Attachment 13 – Demand, p 13-11.

[85] AER Draft Decision, Attachment 13 – Demand, pp 13-9, 13-10.

122. JGN engaged Core Energy to review DAE's findings and respond to the AER's draft decision. Core Energy's report is provided as appendix 3.1. JGN also engaged demand forecasting and econometrics experts Frontier Economics and HoustonKemp to review the Core Energy methodology and DAE's findings relating to the inclusion of a specific variable to capture future economic activity when forecasting per customer consumption for tariff V residential and tariff V I&C customers. The Frontier and HoustonKemp expert reports are provided as appendices 3.4 and 3.5 respectively.

123. Based on this expert advice, JGN is of the view that the AER's rejection of Core Energy's forecasts for tariff V per customer consumption was based on the following three errors:

- the absence of a specific variable to capture future economic activity (for example, the exclusion of GSP or SFD in Core Energy's forecasts) does not mean Core Energy's forecasts are likely to underestimate per customer consumption for tariff V residential and tariff V I&C customers given that economic activity is not a relevant driver of per customer consumption in NSW. Further, there is no clear evidence that economic activity will be different over the forecast period compared to the historical period that merits inclusion of an 'out-of-trend' change in per customer consumption. The inclusion of an economic activity variable as applied by the AER will overestimate forecast consumption
- there is no evidence of a structural change since 2008 in tariff V small business per customer consumption. Use of the full data set available—noting that the full data set is already small—to estimate the trend in small business per customer consumption, as Core Energy have done, is a reasonably-based method to derive the best estimates of small business per customer consumption in the circumstances
- there is no evidence to support DAE's selection of 0.05 for cross-price elasticity. This is simply an arbitrary reduction from the estimate applied by Core Energy, which is a reasonably-based estimate derived by reference to the best available evidence in the circumstances. The DAE finding and AER draft decision to halve the proposed cross-price elasticity variable is based, in part, on the erroneous assumption that there is likely to be an increase in the price of alternative energy products. This is inconsistent with independent third party analysis on forecast decreases in the up-front costs of alternative products such as solar and recent policy reviews, including the Australian Government's Expert Panel's review and recommendation to retain the significant subsidies currently available to households and businesses to install solar panels under the Renewable Energy Target (**Warburton Review**).

124. The AER's rejection of Core Energy's forecasts of tariff V net connections was based on the following three errors:

- for tariff V residential connections:
  - *new connections mix*—the AER's dwelling allocation assumptions are based on a single data set and therefore, do not take into account broader, relevant factors as considered by Core Energy. Core Energy's rigorous analysis of all relevant drivers provides the proper foundation for deriving the best estimates in the circumstances
  - *disconnections*—there is no evidence of a structural change from 2011 onwards in residential disconnections, with disconnections after 2011 representing abnormally low results. On this basis, it was unreasonable for the AER to reject Core Energy's approach to observing a longer-term trend in residential disconnections, which in this case, derives the best estimates in the circumstances.
- *for tariff V small business connections*—there is no evidence of a structural break since 2008 in small business tariff V total connections. As above, using the full data set available to estimate the trend in small business connections, as Core Energy have done, is a better and reasonably-based method to derive the best estimates in the circumstances.

125. Each of these errors is considered further below.

3.4.2 AER'S ERRORS IN REJECTING CORE ENERGY FORECASTS OF PER CUSTOMER CONSUMPTION

3.4.2.1 No under-estimation for tariff V residential and tariff V I&C segments due to absence of a specific variable to capture future economic activity

126. For Core Energy's methodology to underestimate tariff V residential and tariff V I&C per customer consumption due to the absence of a specific variable to capture future economic activity (for example, GSP or SFD) two conditions need to be met:

- first, there must be reliable evidence that the level of economic activity is a driver of per customer consumption for these customer segments
- second, there must be a reliable evidence to conclude that changes in the level of economic activity over the review period—if they do impact on per customer consumption—are not sufficiently reflected in the historic trend.

127. Both of these conditions have not been satisfied by DAE's analysis. For reasons provided below, the AER's rejection of Core Energy's forecast of tariff V residential and tariff V I&C per customer consumption, because they did not include an economic activity variable, was not arrived at on a reasonable basis.

128. Further, to reject Core Energy's methodology based on these conjectures, the estimated per customer consumption for each segment derived from DAE's regression models (even if they were reliable) would need to establish that Core Energy's forecasts are too low. As discussed further below, DAE's actual regression forecasts (as opposed to the forecasts DAE ultimately submitted to the AER) produces results which are lower than Core Energy forecasts for residential customers. That is, DAE's own regression results (when calculated correctly) do not suggest Core Energy's forecasts are too low. If anything, they suggest they could be too high.

First, there is no evidence that changes in the level of economic activity impact on per customer consumption for tariff V residential and tariff V I&C customers

129. DAE's conjecture, which was accepted by the AER, that economic activity is a driver of changes in per customer consumption for tariff V residential and tariff V I&C, is not supported as a matter of economic theory or empirical testing.

There is no economic theory to support the inclusion of SFD as a variable when forecasting residential per customer consumption

130. It can be expected that the level of, and change in, economic activity may impact on overall connections and disconnections. However, it is not necessarily the case that the level of economic activity is a driver of per customer consumption.

131. For example, as a matter of rational inference, in relation to the conjecture that residential per customer consumption is influenced by changes in SFD, we note that:

- SFD, as measured by the Australian Bureau of Statistics (**ABS**), is an economic measure of "expenditure by households and governments, and also includes expenditure on fixed assets within the economy".[86] It is not rational to expect that a measure of state final expenditure, or changes in that expenditure, would be a driver of expenditure of gas by households. It is perhaps more reasonable to expect expenditure on gas is an input, or driver (though unlikely to be material), of SFD, not the other way around. If there was any relationship it may well simply reflect correlation and not causation. Accordingly, it would not be rational to conjecture that forecast changes in SFD will result in changes in residential per customer consumption

86 HoustonKemp, *Review of Gas Consumption Forecasting Methodology*, February 2015, p 9 (**HoustonKemp Expert Report**).

- SFD includes material elements that are unrelated to the residential gas market (or household or private expenditure generally which might otherwise support changes in consumption behaviour). For example, SFD comprises government expenditure (including infrastructure investment) and changes in private fixed capital formation which have no obvious rational relationship to household consumption.[87] Changes in SFD due to changes in government expenditure and fixed capital formation may differ from changes in the level of household expenditure, such that forecast (and historical) changes in SFD may not reflect changes in household expenditure. Relevantly, if forecast changes in SFD are driven by anticipated increases in government expenditure or fixed capital formation, such changes will not provide a reasonable basis to estimate changes in household expenditure (and therefore gas consumption)
- it is not clear why per customer consumption for tariff V residential customers would be materially affected by changes in macro-economic variables. Changes in macro-economic variables are not inherently likely to result in material changes in the use of gas for household heating, cooking or hot water—that is, gas consumption is not generally considered to be discretionary. For example, there appears to be no rational basis to think people will cook more, have more hot showers or heat their house more based on growth in economic activity.

132. There are no *a priori* reasons provided by the AER to include a specific variable for future economic activity in forecasting residential gas consumption per customer. Neither DAE nor the AER discuss any specific rationale for including SFD as a driver of consumption per connection or cite any third party evidence, studies or statistical analysis for why this parameter is relevant, in the circumstances.

There is no reliable empirical basis to support the inclusion of SFD and GSP as variables for tariff V residential and I&C per customer consumption respectively

133. As noted above, it is important that any explanatory variable chosen to forecast per customer consumption has a sound theoretical basis. However, it is equally important that statistical-based validation testing is undertaken to ensure that the modelling specification uncovers genuine relationships between the relevant parameters.

134. For detailed reasons set out in section 3.5, we consider that the DAE regression model also does not reliably establish any such empirical relationship between SFD and tariff V residential per customer consumption, or GSP and tariff V I&C per customer consumption. Specifically, both HoustonKemp and Frontier test whether DAE’s regression models produce reliable results by examining the data used, as well as applying standard statistical tests. These experts note that the statistical results of the regression models vary considerably to minor changes in the data used, and that variables used in both DAE’s residential and I&C consumption per connection models fail standard statistical tests.

135. Specifically, Frontier’s expert opinion is that:[88]

> *… DAE's models cannot be relied upon for the following reasons:*
>
> 1. *The specification of the economic activity variable means that the model is unlikely to have uncovered genuine economic relationships. Rather, our opinion is that the results of DAE's models reflect spurious correlation between gas consumption and the economic activity variables that DAE use, which cannot be relied upon to continue in future.*
> 2. *DAE's results are not stable with respect to changes in input assumptions (for instance, using all the data up to 2013) or to minor changes in model specification. This indicates that the models are not robust.*

87 HoustonKemp Expert Report, p 9.

88 Frontier Economics, Gas Consumption forecasts for JGN’s Tariff V customers, February 2015, p 24 (**Frontier Expert Report**).

136. Similarly, HoustonKemp finds that variables used in the DAE models for both tariff V residential and I&C per customer consumption fails "standard statistical tests" which mean that "the resultant parameter estimates are biased and unreliable".[89]

137. Frontier and HoustonKemp therefore conclude that the results from DAE's models cannot be reasonably relied on as establishing a relationship between economic activity parameters such as SFD and GSP and tariff V per customer consumption.

138. The experts' observations are consistent with Core Energy's observations as part of its initial forecasting process. Core Energy advised that they considered economic activity variables as part of their standard forecasting process, but rejected them as irrelevant, because empirical testing demonstrated that the variables had poor statistical performance for predicting changes in per customer consumption.[90]

It is necessary to consider the particular circumstances to inform the appropriateness of per customer gas consumption drivers

139. In specifying drivers of gas consumption for forecasting purposes, it is necessary to consider the particular circumstances. Relevantly, Core Energy has completed consumption forecasts for every jurisdiction in Australia and has observed material variances in the relationship between economic aggregates and per customer consumption. In their view, a case-by-case or "fit for purpose" approach to determining the relevant drivers of per customer consumption is necessary to determine reasonably-based best estimates.

140. More specifically, a case-by-case approach is demonstrated by reference to the approach taken by Core in preparing forecasts for Envestra's Victoria and Albury gas networks. The AER draft decision incorrectly states that in that case, Core Energy included GSP in its forecasting model of residential gas consumption.[91] It is clear from Core Energy's report for Envestra that Core used GSP as a driver of gas demand for I&C customers, but not for residential customers.[92] For residential customers, Core Energy identified household income as a driver of gas demand.[93] This is a clear misinterpretation by the AER.

141. The reason for Core Energy's departure in its model specification for JGN's network as compared to its approach for Envestra's network is simply that it observed a statistically significant relationship between economic activity variables for forecasting Envestra's gas consumption which it did not observe in the case for JGN.[94] Critically, Core considers that several factors could explain the significance of the relationship it observed in Victoria for Envestra, including a materially higher penetration rate of gas connection in Victoria, a materially different climate, and a materially different consumption per connection in Victoria which is approximately double that observed for NSW.[95]

142. The need to look to whether economic activity variables can be empirically validated is also supported by AEMO. In particular, a report by ACIL Allen for AEMO (and referenced by DAE in its report) suggested that residential gas consumption is likely to be related to household income. However, in that case, AEMO's preferred econometric model for tariff V per customer consumption did not include household income (or GSP

89 HoustonKemp Expert Report, p v.

90 Core Energy Report in response to AER Draft Decision, February 2015, pp 13-14.

91 AER Draft Decision, Attachment 13 – Demand, p 13-12.

92 Core Energy Group, *Demand, Energy and Customer Forecasts*, Envestra Limited - Gas Access Arrangement Review Victoria and Albury Networks (2013 to 2017), March 2012 (**Core Envestra Report**).

93 Core Envestra Report, p 32.

94 Core Energy Report in response to AER Draft Decision, February 2015, p 14.

95 Core Energy Report, August 2014, p 7.

as a potential proxy) as an independent variable because “the coefficients display poor statistics or have coefficients outside the expected range”.[96]

143. For reasons considered above, as well as further below in section 3.5, the AER has not provided sound theoretical or empirical evidence to conclude that Core Energy’s forecasts underestimate tariff V residential and tariff V I&C per customer consumption forecasts because of the non-inclusion of a specific variable for economic activity. To the contrary, by including GSP and SFD as drivers of per customer consumption, DAE’s regression models are likely to introduce bias within the forecasts—in this case, an upward bias in forecast per customer consumption.

> **Conclusion**: The conjecture that economic activity is a relevant driver of changes in per customer consumption for tariff V residential and I&C customers is not supported as a matter of economic theory and/or empirical testing. Therefore, the AER did not have a reasonable basis for concluding that Core Energy’s approach was flawed by not including a separate economic activity parameter.

Second, there is insufficient evidence that changes in level of future economic activity will be outside the trend

144. Even if it is accepted that economic activity is a driver of per customer consumption, in order to establish that Core Energy's forecasts are likely to underestimate per customer consumption it would need to be established that economic activity over the forecast period is likely to be greater than over the historical period.

145. For reasons below, we consider that the AER does not have a reasonable basis for concluding that changes in the level of economic activity in NSW, even if they do impact on per customer consumption, will deviate above the historical trend.

146. In its draft decision, the AER note that Core Energy used a time series approach as the starting point for estimating per customer consumption and concluded that:[97]

> *this approach includes problems, including a lack of information about future economic activity to alter the path from the historical trend. This approach is reasonable where there is no expectation of a change in economic outlook. However, that is not the case when we compare the outlook for the next access arrangement period compared with the current.*

147. There are a number of problems with this conclusion.

148. First, there is no reason why a time series approach cannot adequately and reliably address changes in future economic activity from the historical trend if that is relevant. The trend analysis used by Core Energy can account for circumstances in which key drivers of gas demand are expected to be above (or below) outcomes that occurred during the historical period used to support the trend analysis. For instance, if growth in GSP is accepted to be a driver of gas demand, and growth in GSP is forecast to be higher over the forecast period than the historical period used to support the trend analysis, then the effects of this “out-of-trend” GSP growth can be accounted for as a post-modelling adjustment. For these reasons, there is no inherent reason why such factors cannot be accounted for in a time series or trend approach and must be addressed in a regression or “structural” approach.

149. Second, there are considerable difficulties with econometric regression models, which are reflected in the significant problems identified with DAE’s model noted in section 3.5. Specifically, there are inherent difficulties

96 AEMO, Forecasting Methodology Information Paper, National Gas Forecasting Report 2014, December 2014 (**AEMO Methodology Paper**), p 10.

97 AER Draft Decision, Attachment 13 – Demand, p 13-12.

in establishing a regression model with a limited data set and that reliably includes all factors that influence per customer consumption (including, for example, energy policy, housing heat efficiency and appliance energy efficiency). In contrast, such factors will be captured in Core Energy's historical trend if they are relevant. This was noted by Frontier, observing that Core Energy's trend approach in this case is not inconsistent with the demand forecasts prepared for Envestra's gas networks in Victoria and Albury:[98]

> *The fact that Core identified GSP and GHDI as drivers of gas demand for Envestra's gas networks in Victoria and Albury, and developed econometric models with GSP and GHDI as variables, is not inconsistent with Core using trend analysis to forecast gas demand for Jemena's network area. Even assuming that the evidence were to support the conclusion that GSP and GHDI are drivers of gas demand for Jemena's network area, the historical trend that Core identifies for gas consumption per connection for tariff V Residential customers will reflect the historical impact of GHDI, and the historical trend that Core identifies for gas consumption per connection for tariff V I&C customers will reflect the historical impact of GSP. Trend analysis will naturally account for all factors that cause the historical trend, and specific variables are required only to adjust the trend projections for future out-of-trend changes to one or more relevant drivers.*

150. Third, and most fundamentally, the AER's conclusion rests on the premise that there is reliable evidence that forecast economic activity will be higher than the historical trend.

151. It is unclear what historical period DAE are considering in arguing that future economic activity will be greater than past economic activity. DAE refer to historical economic activity during the period used by Core Energy to support the trend analysis (2002 to 2013),[99] historical economic activity during the period of the most recent determination[100] and historical economic activity since the global financial crisis.[101] On balance, however, it would seem that economic conditions since 2008 were most important in DAE forming the view that a trend analysis of the type that Core Energy adopted was inappropriate in the circumstances:[102]

> *Given the expected changes to gas prices over the next five years, as well as the considerable economic changes that have occurred since 2008, the structural approach was deemed more appropriate for developing gas consumption forecasts over the Review Period.*

152. In this context, Frontier observe that there is a clear error in the DAE (and AER) comparison between economic activity over only part of the historical period and expected economic activity over the forecast period to determine a step-change from the historical trend:[103]

> *…in order for Core's trend analysis to under-forecast consumption over the forecast period it must at least be the case that economic activity over the forecast period is expected to be greater than trend economic activity over the historical period used by Core in its trend analysis. Core's trend analysis will naturally reflect any effect of economic activity over the period 2002 to 2013, so would*

98 Frontier Expert Report, p 11.

99 See, for instance, page 11 of the DAE Report, November 2014: "In particular, during the historical period used to support the trend analysis (2002 to 2013), NSW gas consumption was subject to considerable economic changes brought on by the global financial crisis ..." This could be taken to suggest that DAE's consideration of historical economic activity is focused on the period 2002 to 2013 or just the global financial crisis.

100 See, for instance, page 12 of the DAE Report, November 2014: "Deloitte Access Economics forecasts an average GSP growth of 2.5% annually across the 7 year outlook period, compared with an average 1.9% in the last 5 years." And: "... Deloitte Access Economics is expecting both GSP and SFD to be generally higher over the Review Period than has been seen over the last five years ...".

101 DAE Report, November 2014, p 11.

102 DAE Report, November 2014, p 11.

103 Frontier Expert Report, p 34.

> *only need to be adjusted if economic activity is expected to differ from what occurred over this period 2002 to 2013.*

153. That is, whether the historical trend generates forecasts that are consistent with expected economic conditions over the forecast period should not be assessed by considering economic conditions over only part of the historical trend (for instance, over the period of the last determination or over the period since the global financial crisis)—an analysis of economic conditions over the full historical period used to support the trend analysis must be considered.

154. On the basis of this analysis, Frontier observe that Core Energy's trend analysis is based on a historical period of economic activity that was, on average, stronger than is forecast by DAE:[104]

> *For NSW SFD, DAE's forecasts are for weaker growth in economic activity over the forecast period than the average over the period from 2002 to 2013. DAE forecasts that the average of the annual change in SFD over the period 2014 to 2019 will be 2.59 per cent, compared with the average of the annual change in SFD over the period 2002 to 2013 of 2.92 per cent.*

155. In short, the key premise on which the AER rejected Core Energy's forecasts, concluding that it was likely to underestimate residential customer consumption, namely that forecast economic activity would be higher, is simply factually wrong. Contrary to the AER's conclusion, if there was such a relationship, Core Energy's extrapolated historical trend would, if anything, likely overstate tariff V residential per customer consumption over the next AA period. Simply, the AER has made a clear error in determining that Core Energy's forecasts underestimate residential per customer consumption in the absence of an economic activity (SFD) variable.

156. In any case, actual economic activity for 2014 demonstrates that DAE's forecasting approach is unable to reliably predict changes in SFD and GSP. Specifically, Frontier observes that:[105]

> *For NSW SFD, the DAE Report has a forecast of the annual change in SFD for 2014 of 3.52 per cent, while the outcome for 2014 reported by the ABS is 2.92 per cent, which is the same as the average outcome over the period 2002 to 2013 (2.92 per cent).*
>
> *For NSW GSP, the DAE Report has a forecast of the annual change in GSP for 2014 of 2.76 per cent, while the outcome for 2014 reported by the ABS is 2.08 per cent, which is close to the average outcome over the period 2002 to 2013 (2.03 per cent).*

157. In other words, using the average of the annual change in NSW SFD and GSP over the period 2002-2013 (which is the historical period used by Core in its trend analysis) would have provided a much better forecast of growth in NSW SFD and GSP for 2014 than adopting DAE's forecasts. That is, future increases in economic activity for SFD and GSP are more likely to align with the trend observed over the full data series and therefore not require a post-modelling adjustment. We have no reason to believe that DAE's forecast of average GSP and SFD growth over 2014-2019 would be more reliable than its forecast for 2014.[106]

158. For the above reasons, the evidence before the AER is simply not sufficient to sustain the conclusion that Core Energy's forecasts underestimate tariff V I&C per customer consumption in the absence of an economic activity (GSP) variable.

159. As noted above, the effects of economic activity over the historic period would already be reflected in the historical trend in per customer consumption for tariff V I&C customers. The absence of any clear evidence to support forecast material increases in economic activity to warrant a departure from that historic trend means that it was unreasonable for the AER to reject Core Energy's approach.

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104 Frontier Expert Report, p 34.

105 Frontier Expert Report, p 35.

106 Frontier Expert Report, p 35.

Conclusion: DAE's analysis and data does not provide a reliable econometric basis to conclude that the absence of a specific variable to capture future economic activity means that Core Energy's forecasts of tariff V residential and tariff V I&C per customer consumption are likely to be underestimated.

3.4.2.2 No evidence of a structural change in small business per customer consumption in 2008

160. The AER used a 2008-2013 time period for forecasting per customer consumption for tariff V small business customers, having regard to an apparent step change in data from 2008. The AER relied on DAE's advice that data before 2008 exhibited a "strong decline in per customer consumption, relative to the stable demand post-2008."[107]

161. The AER's use of the 2008-2013 data results in a forecast decline of 2.5 per cent, as compared to Core Energy's forecast decline of 3.2 per cent using the full time series available.

162. JGN assumes that a structural change refers to a material and sustained change in a material driver of small business per customer consumption to warrant the exclusion of data. The AER does not provide any specific detail on the circumstances which have changed post-2008 to support the conjecture of a structural change in small business per customer consumption or refer to any independent study or analysis.

163. Core Energy considers that there is no quantitative evidence of a structural change in 2008 for per customer consumption. Specifically, Core Energy compared the annual change in small business demand and per customer consumption over the two time series. Table 3–2 demonstrates that average annual growth in per customer consumption measured by the proportional change between the 2003-2013 and 2008-2013 is not significantly different (i.e. -2.9 per cent versus -2.7 per cent).[108]

Table 3–2: Annual change in small business consumption and per customer consumption

Growth Rates (%)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Avg 2002-13	Avg 2008-13
Weather Norm. Demand	3.89	4.48	2.64	2.90	5.51	7.30	3.40	10.71	4.58	7.05	1.86		
Demand / Connection	13.10	10.41	8.29	8.10	2.38	5.05	15.33	9.00	1.60	5.00	1.16	**-2.91**	**-2.66**

164. For a structural change to be evident, JGN would expect there to be a material difference in the trend observed between the two periods. The above analysis does not provide any evidence of a fundamental or material change in small business per customer consumption to warrant the exclusion of pre-2008 data. On this basis, we do not consider that the AER had a rational basis to exclude the 2002-2008 data (approximately half the data-set) from the time series.

Conclusion: Compared to the 2008-2013 data, the 2002-2013 time series provides better and reasonably-based estimates of tariff V small business per customer consumption.

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107 AER Draft Decision, Attachment 13 – Demand, pp 13-10, 13-13.

108 Core Energy Report in response to AER Draft Decision, February 2015, p 20-22.

3.4.2.3 No evidence to support reduction in cross-price elasticity to 0.05

165. The AER's draft decision rejected JGN's factor for cross-price elasticity based on DAE's advice, reducing it from 0.1 to 0.05. DAE considered that "on balance, it may be reasonable to include an estimate of cross-price elasticity in per customer consumption forecasts", however it considered that JGN's value was too high.[109]

166. Core Energy arrived at a cross-price elasticity of 0.1 based on extensive international literature research which provided it a useful basis for estimating the cross-price effect.[110]

167. Specifically, Core Energy took the lower end of the range of cross-price elasticity factors identified from literature results to mitigate the risk of overestimating the impact of forecast increases in electricity prices on gas demand.[111]

168. In JGN's view, DAE do not provide any persuasive or cogent evidence to support its proposition that Core Energy's estimate is too high.

169. First, DAE considered that Core Energy's value was too high as ACIL Allen, in its gas forecasting work for AEMO, had not found any modelling which produced a statistically significant estimate for cross-price elasticity. However, this an oversimplification of ACIL Allen's analysis and reasoning on cross-price elasticity in forecasting gas consumption. ACIL Allen noted there will be a material impact on gas demand caused by cross-price elasticity with substitutes including electricity[112]:

> *Increasing gas costs to businesses over the next few years – the likes of which have not been experienced before – are likely to reveal the underlying elasticity of demand for gas and also the cross-elasticity of substitute products (such as coal for steam raising in industrial settings or reverse cycle air conditioning for heating purposes within households).* ***Forecasts which rely on historical relationships are likely to over-estimate gas consumption as households and business make consumption and equipment decisions based on substantially altered financial trade-offs****.* (Emphasis added)

170. ACIL Allen's non-inclusion of a cross-price elasticity factor in its particular methodology seems to be premised on data limitations, rather than the absence of a real and material cross-price elasticity effect. Core Energy's approach to estimating cross-price elasticity, involving an extensive review of third party literature, seeks to determine the best estimate of the forecast impact of relative electricity prices on gas consumption in the circumstances (including historical data limitations, and that fact that it is clear that a material, out-of-trend relationship, will exist between electricity prices and gas per customer consumption).

171. Second, DAE contend that its own-price elasticity estimates are higher than Core Energy's and so to avoid double counting, DAE considered it appropriate to have a lower cross-price elasticity. For the following reasons we consider that DAE did not have reasonable grounds for arbitrarily reducing Core Energy's cross-price elasticity:

- Core Energy's approach to forecasting the cross-price elasticity of gas consumption takes care to ensure that double counting is avoided, through focused analysis and use of conservative factors. In particular, Core Energy notes the following:[113]

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109 AER Draft Decision, Attachment 13 – Demand, p 13-14.

110 Core Energy Report, April 2014, pp 88-89; Core Energy Report in response to AER Draft Decision, February 2015, pp 22-23.

111 Core Energy Report, April 2014, pp 88-89; Core Energy Report in response to AER Draft Decision, February 2015, p 24.

112 ACIL Allen Consulting, 'Gas Consumption Forecasting – A Methodology", Report to Australian Energy Market Operator, 24 June 2014, p A-3.

113 Core Energy Report in response to AER Draft Decision, February 2015, p 24.

Core's own price elasticity calculation focuses purely on the demand response attributable to a movement in gas prices. The elasticity factors applied are conservative relative to other international studies and DAE's own estimates and are in accordance with the approach and results previously approved by the AER.

Core's cross-price elasticity factor focuses purely on the demand response attributable to a movement in relative price of electricity and gas prices as substitute energy sources. The elasticity factor applied is conservative when considered against the full range of international studies. Further the studies used as a basis for deriving the cross-price factor have been reviewed by Core to ensure they adequately address the independent impact of cross and own price elasticity factors.

- DAE's reasoning that its higher own-price elasticity requires a lower cross-price elasticity than Core Energy's to avoid double-counting is flawed. DAE's regression model does not account for cross-price elasticity within the model, rather, DAE apply an out-of-model factor for cross-price elasticity. Given the impact of electricity prices on gas demand due to substitution, when this cross-price elasticity factor is not explicitly incorporated within the model, this effect will tend to reduce the own-price elasticity estimated by the model – such that separating out the effect of cross-price elasticity would require an increase in the own-price elasticity, not an arbitrary reduction in the allowance for cross-price elasticity.[114]
  - the fact that DAE's regression model produced higher estimates for own-price elasticity than Core Energy applied (if DAE was to accept its regression model as reliable), should have led DAE to conclude that Core Energy's forecasts are *conservative* when accounting for own-price elasticity effects. This observed lower own-price elasticity applied by Core Energy, could not rationally provide a basis for reducing Core Energy's allowance for cross-price elasticity effects.
- in any event, there is no rational basis to make an arbitrary reduction in cross-price elasticity, by reference to the allowance for own-price elasticity. There is no necessary correlation—for example, if gas prices are constant over time, and electricity prices declined, then there would be no offsetting effect.

172. Third, DAE contend that it is expected that residential customers will have a greater short-term ability to switch between gas and electricity, while I&C customers may need to amend production processes or other business infrastructure in order to make the change. However, this conjecture does not support DAE's change to the residential cross-price elasticity factor. It would only suggest that there should be a different cross-price elasticity for non-residential customers.[115] It provides no rational basis for a reduction in the cross-price elasticity for residential customers.

173. Finally, DAE contend that the 'price' of alternative (largely green) energy products, such as solar, are likely to rise in the next AA period compared to the previous period as subsidies and other factors making them attractive are reduced or eliminated. Again, this proposition provides no basis for the arbitrary reduction in cross-price elasticity. Further, there is no evidence for the DAE proposition. A review of recent market analysis and policy statements would provide DAE and AER with a range of evidence that contradicts its assumption, including:

- independent third party analysis which suggests that there is likely to be continued forecast decreases in the upfront costs of alternative products such as solar (with a range of views on how steep the decline will be)

114 Put another way, if electricity prices and gas prices move in tandem, then the combined impact of price changes on demand is captured by the sum of the own-price and the cross-price elasticity. If there is no electricity price in the regression model, then the estimated gas price elasticity in the fitted model will be an estimate of the combined own-price and cross-price effect – i.e. it will be the sum of the two elasticities. If DAE want to have the same combined effect as Core Energy, but have a bigger (negative) own-price elasticity, then they also need a bigger (positive) cross-price elasticity to get to the same combined effect as Core Energy.

115 We note ACIL Allen's view (expressed above), that there is a material fuel substitution effect expected for business customers going forward.

- recent policy reviews including the Australian Government's Expert Panel's review and recommendation to retain the significant subsidies currently available to households and businesses that install solar under the Warburton Review.[116]

174. For the above reasons, over the period of the Core Energy historical trend series, the price of alternative (largely green) energy products, such as solar, are likely to have been consistently higher than in the future.

175. In conclusion, the finding that a cross-price elasticity factor of 0.05 is appropriate appears to be simply an arbitrary reduction from the estimate applied by Core Energy, with a range of erroneous arguments advanced to support a lower number.

176. On the evidence before it, the AER could not rationally conclude that an estimate of 0.05 for the effect of cross-price elasticity has any precedent acceptance or reflects a reasonably-based, best estimate in the circumstances. JGN considers that the methodology used by Core Energy to derive a cross-price elasticity factor of 0.1 continues to provide the best estimate of gas consumption under the circumstances.

Conclusion: Use of Core Energy's cross-price elasticity factor, which was transparently determined and academically supported, results in the best, reasonably-based estimate of forecast per customer consumption in the circumstances.

3.4.3 AER'S ERRORS IN REJECTING CORE ENERGY FORECAST OF CONNECTIONS

3.4.3.1 The AER's alternative dwelling mix for new connections does not reflect the best estimate possible in the circumstances

177. The AER determined that based on Housing Industry Association (**HIA**) data, a 44 and 56 per cent allocation respectively for new estate and medium/high density connections produced a better estimate than Core Energy's allocation estimate of 48 and 52 per cent respectively. In rejecting Core Energy's allocation estimates, the AER asserted that Core Energy's allocation was based on a range of third party analysis, but Core "*did not provide the details of this third party analysis*".[117] This statement is incorrect.

178. Core Energy referred to a number of third party research reports to derive an estimate of the split between new estates and medium/high density dwellings.[118] These included BIS forecasts of NSW dwellings, analysis of NSW residential property markets undertaken by NSW government agencies, councils and major trading banks and real estate organisations.[119]

179. Core Energy considers the approach used by it to arrive at the allocation between new estates and medium/high density dwellings has a strong technical and commercial basis and provides the best estimate available in the circumstances. Rather than relying on a single data source, Core Energy's approach to deriving its allocation estimate involved a consideration of HIA and BIS Shrapnel data, as well as the other third party reports.[120] Specifically, Core considered the following in deriving its allocation assumptions:

- a review of HIA housing data and forecasts which indicated a higher level of multi-unit starts in the future than historically (approximately 5 per cent higher)

116 Core Energy Report in response to AER Draft Decision, February 2015, p 25.

117 AER Draft Decision, Attachment 13 – Demand, p 13-16.

118 Core Energy Report, April 2014, pp 59-61; Core Energy Report, August 2014, pp 17-18.

119 Core Energy Report, April 2014, pp 59-61; Core Energy Report, August 2014, pp 17-18.

120 Core Energy Report, August 2013, pp 17-18.

- a review of the BIS Shrapnel indicates that higher density dwelling will fall within the range 50-52 per cent during the forecast period. Specifically, this report incorporates an average of almost 49 per cent new estate and almost 51 per cent medium/high density connections in the 2016-18 period reports from the NSW Department of Planning and other authorities on dwelling projections.

180. Specifically Core Energy's allocation assumption balances the evidence that new estates as a proportion of total dwellings have been above higher density dwelling in recent history, as well as that the NSW will observe a move toward increased higher density dwelling construction. Taking into account the range of available evidence, Core derived a split of 48 per cent to new estates and 52 per cent to medium/high density, representing the forecast allocation in 2018 based on the BIS analysis.

181. JGN considers that Core Energy's approach reflects rigorous industry and sectoral analysis, with thorough analysis of both supply and demand drivers. This is to be contrasted with the AER's decision to adopt HIA data with no further third party analysis or consideration of broader circumstances. JGN is of the view that a method that ignores relevant and current analysis does not meet the requirements of rule 74(2).

Conclusion: JGN considers that Core Energy's estimates for dwelling mix, validated by third party analysis, continues to provide the best, reasonably-based estimate for new connections in the circumstances, and the AER has not provided any evidence that causes JGN to adjust its position.

3.4.3.2 No evidence of a structural change in small business connections in 2008

182. The AER determined that pre-2008 data should be excluded from forecasting small business connections as a result of a "structural break in the series in 2008, where there was a significant step change in the number of connections".[121] The AER relies upon DAE's analysis of total new connections per year before and after 2008 to assert that by including pre-2008 data the average growth rate in connections is overstated.[122] Similar to DAE's contention that there was an apparent step change in 2008 for small business per customer consumption, DAE does not indicate any specific driver (or drivers) which underpin the step change in new connections.

183. Core Energy considers that the better view of assessing whether there has been any material step change in connections over the time series is to consider movements in *net* connections—that is, a consideration of movements in disconnections, and other balancing items, rather than just new connections.

184. Core Energy undertook this analysis to assess whether there is a structural trend in net connections. It observed that there were a material number of net connection movements accounted for within the disconnections and balancing items classification. From this analysis, it determined that it was unable to observe a structural change in 2008 given the year to year variability in net connections.[123]

185. On this basis, JGN considers that the AER did not have a reasonable basis for rejecting Core Energy's forecast because it took into account the complete trend time series.

Conclusion: The 2002-2013 time series provides a better, reasonably-based estimate for forecasting connections for tariff V small business.

121 AER Draft Decision, Attachment 13 – Demand, p 13-10.

122 AER Draft Decision, Attachment 13 – Demand, p 13-17.

123 Core Energy Report in response to AER Draft Decision, February 2015, pp 29-30.

3.4.3.3 No evidence to support structural change in residential disconnections from 2011 onwards

186. The AER determined that Core Energy's residential disconnections forecasts were overstated as a result of the inclusion of 2002-2010 data. This is because the AER observed that the number of disconnections over the 2011-2013 period were more stable than previous.

187. Core Energy has reviewed the AER's analysis and DAE's workings and observed that:[124]

- during 2011-2013, electricity prices increased at an average of 16 per cent p.a., an increase of almost twice the corresponding increase in gas price, making a gas disconnection a less compelling offer
- in contrast, during 2002-2009, electricity prices increased by an average of 4 per cent which was similar to the rate of increase in prices
- over the next AA period, electricity prices are expected to trend materially lower than gas prices and this change in trend is expected to give rise to a disconnection rate which is in line with the longer term 2002-2013 trend.

188. On this basis, JGN considers the disconnection rate over the 2011-2013 period was abnormally low and therefore, is not a reliable basis for forecasting residential disconnections. Instead, observing the trend in residential disconnections across the 2002-2013 time series will derive the most accurate disconnection rate for forecasting purposes.

189. The above conclusion is supported by a comparison between:[125]

- the actual disconnections for 2013-14 reported by JGN, which was 5,894 disconnections and
- the forecast disconnections for 2013-1414 using the alternative time series—using the complete time series results in a forecast of 5,841 residential disconnections which is comparable to the actual forecasts, whereas DAE's use of the 2011-2013 time series results in a forecast of 3,900 disconnections.

190. DAE's forecast is significantly below the actual reported outcomes. This demonstrates that DAE's approach does not derive better forecasts for residential disconnections than Core Energy's approach.

Conclusion: The 2002-2013 time data series provides the best, reasonably-based estimate for forecasting residential connections, in the circumstances.

3.4.4 CONCLUSION

191. The AER's reasons for rejecting JGN's proposed forecasts for per customer consumption and total connections were based on the following clear and material errors in factual finding and exercise of judgment:

- the absence of a specific variable to capture future economic activity (for example, the conclusion of GSP or SFD in Core Energy's forecast) does not mean Core Energy's forecasts are likely to underestimate per customer consumption. This is because there is:
  - no statistical analysis which supports the conjecture that economic activity is a reliable driver of gas consumption for tariff V customers

[124] Core Energy Report in response to AER Draft Decision, February 2015, p 30.

[125] Core Energy Report in response to AER Draft Decision, February 2015, p 31.

- no evidence which supports the conjecture that economic activity over the next AA period, will be greater than economic activity over the historical period

- there is no evidence of a structural change since 2008 in small business per customer consumption use
- there is no evidence to support the selection of 0.05 for cross-price elasticity, and the AER's reasons for rejecting Core Energy's cross-price elasticity are misguided and/or erroneous
- the AER's dwelling allocation assumptions relies on an alternate and single data set, without having regard to broader factors or available and relevant data analysis
- there is no evidence of a structural break since 2008 in small business total connections
- there is no evidence of a structural change from 2011 onwards in residential disconnections, with disconnections after 2011 representing abnormally low results.

192. Therefore, the manner in which the AER arrived at its conclusions in relation to the above matters was not reasonably-based, and should not have led it to reject Core Energy's demand forecasts.

193. For reasons below, we also consider that the AER's flawed rejection of Core Energy's forecasts should not have led it to accept the alternative consumption forecasts prepared by DAE as better estimates in the circumstances—with such forecasts being developed on the basis of an unreliable model specification, containing material errors and producing biased results.

3.5 THE AER'S FORECASTS ARE NOT REASONABLY-BASED: ERRORS IN DAE MODELLING AND ESTIMATES

3.5.1 SUMMARY

194. DAE uses an econometric approach to develop forecasts of per customer consumption for tariff V residential customers and for tariff V I&C customers.

195. DAE attempted a similar approach for tariff V small business customers but concluded that the "… the structural econometric equation for this customer group did not produce reliable and robust results".[126] Rather DAE applied the Core Energy trend forecast methodology, but as noted above, used a smaller data period to derive the trend on the premise that there was a structural change in per customer consumption in 2008.

196. The regression equation for per customer consumption for tariff V residential customers is the following:

$$lnY_t = \propto + \beta_1 \ln(P_t) + \beta_2 \ln(P_{t-1}) + \beta_3 SFD_{t-1} + \varepsilon_t$$

197. This means that the gas price (P_t), the gas price in the previous year (P_{t-1}) and SFD in the previous year (SFD_{t-1}) are used to explain residential per customer consumption.

198. The regression equation for per customer consumption for tariff V I&C customers is the following:

$$lnY_t = \propto + \beta_1 \ln(P_t) + \beta_2 GSP_{t-1} + \varepsilon_t$$

126 DAE Report, November 2014, p 27.

199. This means that the gas price (P_t) and GSP in the previous year (GSP_{t-1}) are used to explain I&C per customer consumption.

200. As noted above, DAE's econometric models include measures of economic activity as explanatory variables for per customer consumption.

201. While it is not explained in DAE's report, it is apparent that the actual forecast estimates used by the AER are not those generated from DAE's regression models. Rather, DAE has used the annual forecast per customer consumption results from their regression models to calculate annual percentage changes from one year to another. DAE then inputs these annual percentage changes in forecast per customer consumption within the Core Energy model. Specifically, for tariff V residential per customer consumption, DAE overrode Core Energy's forecast trend change in per customer consumption (-0.8) and removed the allowance for gas price elasticity. DAE then adjusted down the cross-price elasticity factor from 0.1 to 0.05.

202. DAE's models should not have been accepted by the AER as providing reasonably-based best estimates. This is because "there are serious problems with DAE's econometric modelling"[127]—it is flawed by data errors, producing spurious results and resulting in an upward bias to Core Energy's original forecasts. Accordingly, Frontier and HoustonKemp conclude that DAE's regression approach does not provide a reliable basis for forecasting per customer consumption.

203. In particular, we observe three critical deficiencies within DAE's models:

- the DAE models use a more limited time period of historical data than is available, despite the narrow data set available (see section 3.5.2.1)
- the DAE model specifications are idiosyncratic and not intuitive, based on parameters which produce biased and spurious outcomes. That is, neither of DAE's models for tariff V residential or tariff V I&C per customer consumption would be a candidate model likely to be specified *a priori* (see section 3.5.2.2 below)
- the DAE models contain a number of data errors and anomalies, correction of which results in poorer fitting regression results or otherwise statistically worse outcomes (see section 3.5.2.3).

204. In our view, these issues are sufficiently material to mean that DAE's regression models of per customer consumption are unreasonable and not reliable in the circumstances. We address each of these errors and shortcomings in DAE's approach below.

205. Frontier has also addressed the following question: if the above issues are corrected in DAE's models for tariff V residential and I&C customers, could the results be confidently relied upon. Frontier's conclusion in each case is that none of the alternative models which correct for the above issues derives statistically reliable results. We conclude then, in these circumstances, use of an econometric model is unlikely to produce reasonable and reliable forecasts of gas demand. As a result, the trend approach taken by Core Energy continues to represent the best approach to gas forecasting in these circumstances.

206. The final observation we make is that the per customer consumption forecasts generated by DAE's regression models are not submitted as the alternative forecasts to Core Energy's forecasts. As noted above, DAE have used the annual percentage changes in per customer consumption and added this as a step change in the Core Energy model (after removing for the effect of own-price elasticity). What ultimately DAE submitted to the AER, and which the AER accepted as alternative per customer consumption forecasts, was inconsistent with, and materially higher than, the results of the DAE model itself. That is, the results derived from the DAE models do not support the forecasts actually used by the AER. In fact, the results of the DAE models overall (if they were to be relied on) are closer with Core Energy's forecasts and therefore, do not provide any basis to reject those forecasts as likely to underestimate demand.

127 Frontier Expert Report, p 2.

3.5.2 ERRORS IN DAE TARIFF V PER CUSTOMER CONSUMPTION FORECASTS

3.5.2.1 Problem 1 – exclusion of valid time series data, resulting in false conclusions as to the reliability of DAE models

207. The first issue identified with DAE's regression models is that DAE uses historical data from 2002-2010 in specifying their regression equations for tariff V residential and tariff V I&C customers. However, historical data from 2002 to 2013 was available.

208. There was no statistical reason for DAE to limit the time series used. However, it appears that the reason that DAE use historical data from 2002-2010 is that they initially use this data to conduct an in-sample forecast of outcomes for 2011-2013. DAE explain in their report that: [128]

> *... the regressions were conducted on 2002 to 2010 data, with the model coefficients used to 'forecast' 2011-2013 consumption. This in-sample forecast period was then compared against actual consumption in 2011-2013.*

209. While in-sample forecasting is a common technique, there is no reason that the data for the full period to 2013 should not be used once a model specification has been settled on.[129]

210. This is a particularly significant omission given the overall limited data set. Specifically, in circumstances where there is limited data available, unless there is a sound reason not to include data, all data should be used. In particular Frontier note the following:[130]

> *Indeed, our opinion is that the better approach would be to use the historical data for the full period to 2013. Particularly given that limited historical data is available, more reliable results will be achieved by using the full dataset, unless there are sound statistical reasons to exclude specific data points (for instance, because specific data points are identified as outliers). DAE has not discussed the reason for excluding the data points for 2011 to 2013 (other than by reference to forecasting 2011-2013 for comparison with actual 2011-2013 consumption) and we can see no sound reasons to exclude them.*

211. Frontier tested DAE's models with data for the full period up to 2013 and found slight variations in the statistical results for DAE's tariff V I&C regression model and that for the tariff V residential model, the results are generally poor: either the coefficients have the wrong signs or the statistical performance of the model is worse.[131]

212. HoustonKemp also tested the choice of time period on the statistical performance of the regression parameters for both tariff V residential and I&C per customer consumption. HoustonKemp identified significant variability in the coefficients of the parameters as well as in some cases, the sign of the parameter estimates reversed. The sensitivity of the results of DAE's model to the particular data period raises real questions about the stability and robustness of DAE's approach to forecasting. Specifically, HoustonKemp note that the "specific choice of time period for the regression modelling is driving the results".[132]

213. HoustonKemp considered that the sensitivity of DAE's regression models to changes in the time series used is likely to reflect problems with some of DAE's parameters being "non-stationary". Stationary variables are

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128 DAE Report, November 2014, p 11.

129 Frontier Expert Report, p 13.

130 Frontier Expert Report, p 13.

131 Frontier Expert Report, pp 14-15.

132 Frontier Expert Report, p 13.

explanatory parameters which have constant statistical properties, such as the mean and variance, over the time series. Established statistical theory provides that a regression model must contain stationary variables to produce statistically reliable results. If a regression model includes non-stationary variables the model is likely to yield unreliable predictions.[133] HoustonKemp summarised the implications of using stationary and non-stationary variables in the following terms:[134]

> *To put this more simply, a regression involving a variable that is stationary and one that is non-stationary will lead to parameter estimates that reflect changes in the mean and variance of the non-stationary variable rather than the underlying relationship between the two variables. This leads to the estimated parameters being biased compared to the "true" value. A regression equation with biased parameter estimates means that the estimated relationships between the variables is unreliable.*

214. In respect of the DAE's regression models, HoustonKemp, applying standard statistical testing, identified that two of the four variables are non-stationary for residential per customer consumption and one of the three variables are non-stationary for tariff V I&C per customer consumption.[135]

215. HoustonKemp concluded that the fact that these variables are non-stationary is likely to explain the acute sensitivity of DAE models to changes in inputs and means that the "resultant parameter estimates for each variable in the estimates equation will be biased and so are unreliable".[136] HoustonKemp concludes that:[137]

> *To correct for these variables being non-stationary would require differences to be taken for each variable, until a stationary parameter was identified. However, doing so would further reduce the degrees of freedom, thereby making the entire regression model even less reliable for estimating the model parameters given the limited number of years of available historic data.*
>
> *It follows that in my opinion, the DAE model parameters are unreliable given flaws in the application of the statistical technique, by not accounting for the assumptions that need to be satisfied for OLS to produce reliable parameter estimates.*

216. The significant variability in the results of DAE's regression models should have been sufficient to alert DAE to the unreliability of its models and to reject their use. There is no evidence that DAE conducted any robust assessment of its model to data period selection choices.

Conclusion: There is no rational explanation for DAE's exclusion of the 2011-2013 time series. When the data is included, the DAE model produces significant variability and/or statistically unreliable results which indicate that the models should not be relied upon because they are unstable.

3.5.2.2 Problem 2 – unusual and statistically unreliable model specification

217. DAE provides very little discussion of its choice of independent variables for its regression models, and no ex ante explanation of why they would expect gas consumption to be related to the variables included in their models. A review of the independent variables used in the regression models raises concerns about the reliability and reasonableness of DAE's model specifications.

133 HoustonKemp Expert Report, p 8.

134 HoustonKemp Expert Report, p 8.

135 HoustonKemp Expert Report, p 14.

136 HoustonKemp Expert Report, p 14

137 HoustonKemp Expert Report, p 14.

218. Specifically, Frontier identify several concerns about the independent variables used in DAE's econometric models for forecasting tariff V residential and I&C per customer consumption, each of which materially undermines the reliability of the models and their reasonableness for use in forecasting.

219. As discussed, DAE's regression equation:

- *for tariff V residential customers*—relies upon three variables to explain per customer consumption: level of the gas price in the current year; level of the gas price in the previous year; and change in total SFD in the previous year
- *for tariff V I&C customers*—relies upon gas price and GSP in the previous year.

220. Frontier have analysed the choice of parameters and identify the following curiosities:[138]

- first, DAE use a change in the SFD / GSP rather than the level of SFD / GSP—in particular, DAE use the annual *changes* in SFD / GSP and apply that to adjust the year-to-year *level* of per customer consumption. Frontier advise that parameters should be specified either as all changes or all levels. For example, there might be reason to expect that a change in GSP would affect the change in gas consumption, or that the level of GSP would affect the level of gas consumption, but it is unclear why a *change* in GSP would affect the *level* of gas consumption. In this regard DAE does not discuss its rationale.
  - Frontier tested the use of lagged level of GSP / SFD instead of lagged change in GSP / SFD which resulted in considerably worse statistical fit and the coefficients for GSP and SFD have the wrong sign.
- second, DAE use lagged SFD / GSP only, and exclude current SFD / GSP from consideration. While use of lagged parameters are common in regression analysis (e.g. for price effect), the use of lagged measures of economic activity is less common.
  - for SFD, assuming it was to be used as a proxy for a measure of household income (which is not in fact the reason AER/DAE included it), it might be reasonable to expect customers to respond to changes in household income over time just as they may respond to changes in prices over time. If this is DAE’s proposition, then it is also reasonable to expect that current SFD would feature in DAE’s model, just as current gas price is included in the model.
  - for GSP, Frontier expect the relationship between economic activity and gas consumption by I&C customers to be more immediate – for example, increase in production is expected to require an increase in inputs to the production process, including gas, implying the model should logically have used current GSP not lagged GSP.
  - Frontier tested the inclusion of current year SFD and GSP and determined that in each case, the statistical fit was considerably worse, the coefficients had the wrong sign, and are statistically highly insignificant.
- third, DAE use total SFD / GSP rather than SFD per capita / GSP per capita, in circumstances, where the dependent variable is consumption *per connection*.
  - correcting for this results in a considerably worse statistical fit and the coefficient on the SFD / GSP variables are statistically highly insignificant.

221. In light of the above issues, Frontier analysed a range of other candidate models (that is, it corrected for each of the above issues in isolation and tested differences in statistical performance of the regression models). In short, Frontier concluded that none of these alternative models provides a good fit for the data.

[138] Frontier Expert Report, pp 16-22.

222. In respect of its analysis of alternative model candidates for tariff V residential per customer consumption, Frontier concluded:[139]

> *In short, none of these alternative models…is a good fit for the data. A number of the models have coefficients of the wrong sign …, all models have at least one coefficient that is statistically highly insignificant and all of the models have a statistical fit that is worse than DAE's model. Moreover, the estimates of the own-price elasticities vary widely across the different models and are, with one exception, statistically not significant even at the 10% level. This indicates that the models are not robust. Our opinion is that none of these models provides a reliable basis for assessing the relationship between economic activity and gas consumption for tariff V Residential customers.*

223. Similarly, Frontier's observations about the alternative model candidates for tariff V I&C per customer consumption included the following:[140]

> *In short, none of these alternative models…is a good fit for the data. A number of the models have coefficients for the economic activity variable with the wrong sign …, all models have at least one coefficient that is statistically highly insignificant and all of the models have a statistical fit that is worse than DAE's model. In particular, the economic activity variable is statistically not significant, even at the 10% level, in <u>any</u> of the models. Our opinion is that none of these models provides a reliable basis for assessing the relationship between economic activity and gas consumption for tariff V Commercial and Industrial customers.*

224. As a result, Frontier considers that DAE's regression models (even if modified) have not uncovered any meaningful economic relationship between per customer consumption and economic activity and therefore, does not provide a basis for concluding that economic activity is a driver of per customer consumption for tariff V residential or I&C customers.[141]

225. As a concluding point, DAE provide very little discussion of their choice of independent variables for their regression models, and no *ex ante* explanation of why they would expect per customer consumption to be related to the specified variables for economic activity that they include in their models. Frontier consider that:[142]

> *Given this, and the poor results for other models that are more plausible ex ante, we suspect that the unusual specification of the economic drivers in DAE's regression equations for gas consumption per connection for tariff V Residential customers and tariff V Industrial and Commercial customers is a result of DAE testing a wide range of candidate models and finding that each of these models is one of the few models, or the only model, that provides acceptable results.*

226. In the absence of any rational basis for DAE's model specification, the regression models represent selective parameters and spurious data choices for those parameters to produce a closer fitting model. Accordingly, the sensitivity of the model to changes in data inputs evidences that the model does not reflect underlying meaningful relationships between its parameters.

Conclusion: The problems with DAE's regression models do not only mean that no reliable conclusions can be drawn from the models about the relationship between gas consumption and economic activity, but also that the models cannot be used to produce forecasts that are reasonable and reliable.

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139 Frontier Expert Report, p 19.

140 Frontier Expert Report, p 22.

141 Frontier Expert Report, p 23.

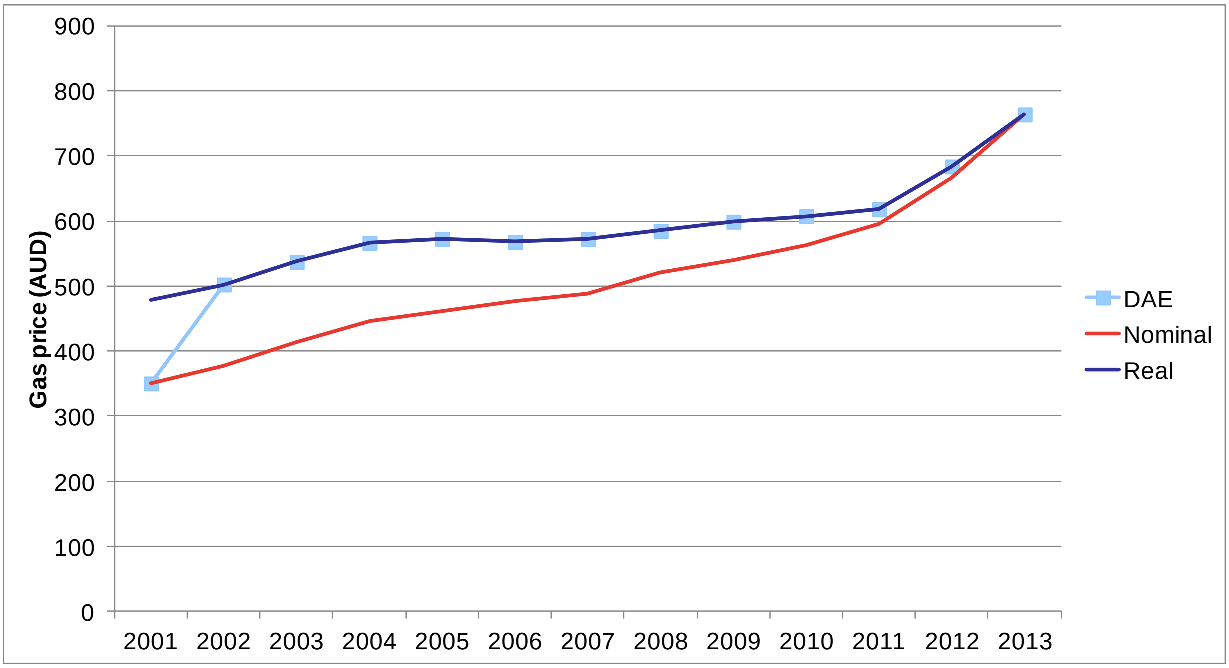
142 Frontier Expert Report, pp 23-24.

3.5.2.3 Problem 3 – basic data transposition errors – resulting in upwardly biased estimates

227. The second serious problem with DAE's models is the existence of two material data errors—compounding existing concerns about the reliability of DAE's approach.

228. The first error relates to tariff V residential customers, where DAE have erroneously used real gas prices for 2001 and nominal gas prices for each subsequent year in their regression equations. Use of 2001 data was required as the DAE model includes both the current gas price and the gas price in the previous year as explanatory variables. The use of real gas prices for 2001 appears to be an error in transcribing the data, the effect of which is illustrated in Figure 3–2.[143]

Figure 3–2: Historical gas prices – use of real and nominal gas prices by DAE



229. This data error directly effects the regression equation for tariff V residential per customer consumption—it produces an erroneously low estimate of price elasticity. Since DAE's econometric model of per customer consumption for tariff V I&C customers does not use a lagged gas price, the data error for 2001 does not affect DAE's model for these customers.

230. In correcting the data error, Frontier observed that the coefficients for all the independent variables change materially while, broadly speaking, the statistical significance of the updated model is not worse than DAE's original model. Correcting for the data error also provides for a higher own-price elasticity of demand and, therefore, the fitted estimates of per customer consumption are materially lower over the forecast period.[144] This highlights again the sensitivity of DAE's regression model to data error.

231. Frontier also considered, if DAE corrected this gas price anomaly, whether it would have likely resulted in DAE favouring a different model for per customer consumption for tariff V residential customers. The model specification with the correct gas price results in a highly insignificant coefficient on current gas price. On this basis if the current gas price variable was dropped from the model specification, it would have resulted in a

143 Frontier Expert Report, p 25.

144 Frontier Expert Report, p 27.

better fitting model—and as above, it would have resulted in a higher estimate of own-price elasticity, and therefore, a lower forecast per customer consumption.[145]

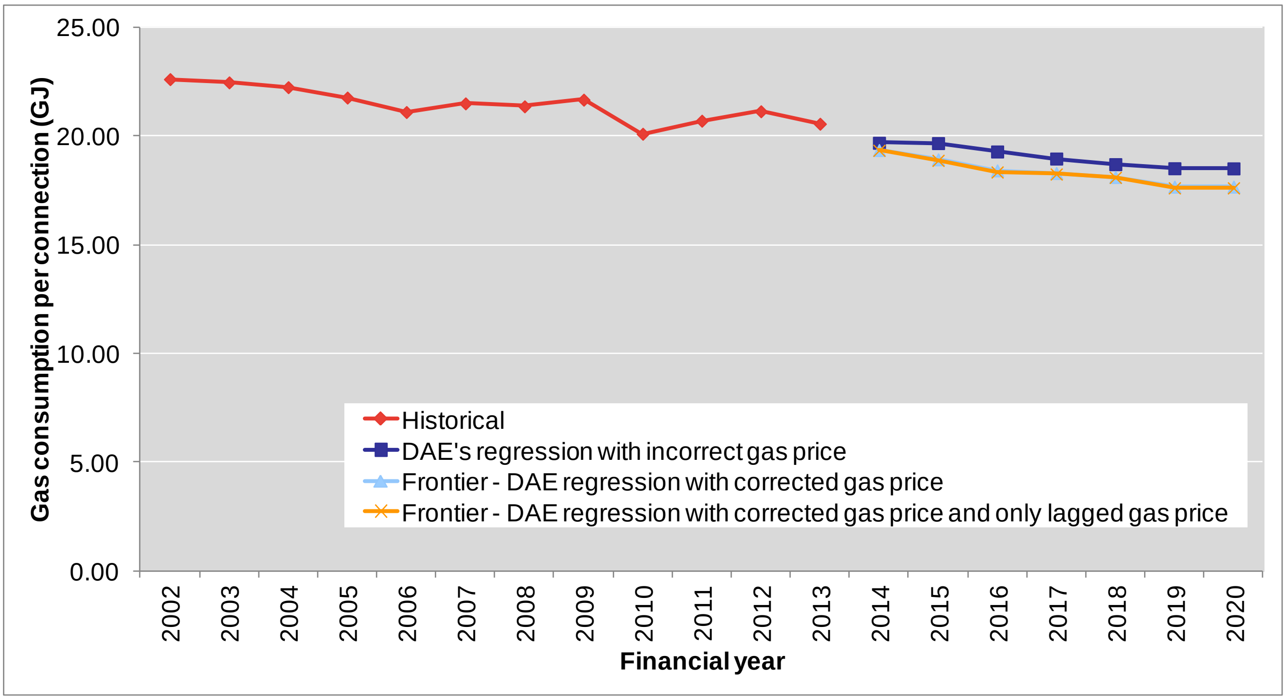
As shown in red to DAE's regression model.

232. Figure 3–3 below, the forecast results for:

- correcting the gas price error as set out in paragraph 230 above; or
- the alternative model specification which also corrects the gas price error, but removes the current gas price parameter, set out in paragraph 231 above,

yield lower per customer consumption for tariff V residential customers over the next AA period compared to DAE's regression model.

Figure 3–3: Residential per customer consumption



233. The second error relates to tariff V I&C customers, where DAE uses historical residential gas prices as a dependent variable, but forecasts of gas prices are based on forecasts of non-residential gas prices (which differ from the forecasts of residential gas prices). There seems to be no rationale for the switch in data type.[146] If there are different factors that drive residential gas prices and non-residential gas price—and there is reason to expect that there are—then non-residential gas prices should be used both in developing the model and in using the model results to forecast per customer consumption.

145 Frontier Expert Report, p 27.

146 Frontier Expert Report, p 24.

Conclusion: The basic data errors contained in the DAE models provide further reasons why its forecasting approach should not have been accepted by the AER.

3.5.2.4 Even if problems 1 to 3 above were addressed, DAE's model still does not provide a reasonable basis for forecasting per customer consumption

234. As noted above, a number of problems with DAE's econometric models have been identified. As Frontier note, there is a further question that needs to be addressed—that is, if the errors identified above were corrected would this result in reliable econometric models for forecasting either tariff V residential or I&C per customer consumption.

235. Frontier finds that that none of the alternative econometric models for either tariff V residential or I&C per customer consumption which corrects for the above issues derives statistically reliable results. Specifically, Frontier concludes that in each case, the corrected models derive a negative combined elasticity— that is, results which are illogical and contrary to economic theory.[147]

236. Frontier concludes that, in these circumstances, use of an econometric model is unlikely to produce reasonable and reliable forecasts of per customer consumption in these circumstances. Frontier attribute this to the data limitations within the regression models:[148]

> *Our attempts to find improved econometric models…have been unsuccessful. This leads us to the opinion that econometric modelling of the data used by DAE is unlikely to produce reasonable and reliable forecasts of gas demand in these circumstances. One reason for this is likely to be the limited data available, with only 12 data points for historical gas consumption per connection available.*

237. Frontier's observations are also consistent with HoustonKemp's views that, given the data limitations, there is no merit in using regression techniques to forecast per customer consumption.[149]

> *In my opinion, the small number of observations used by DAE given the number of explanatory variables means that the regression results are sensitive to the choice of period for the data. …the parameter estimates vary considerably if alternative periods are chosen to estimate the regression models for both residential consumption per connection and industrial and commercial consumption per connection.*

238. In conclusion there is insufficient data to allow for tariff V residential and I&C per customer consumption to be reliably estimated using an econometric model as used by DAE. As a result, Frontier note that a trend approach

[147] Frontier Expert Report, p 31.

[148] Frontier Expert Report, p 45.

[149] HoustonKemp Report, p v. HoustonKemp explain the concept of degrees as freedom as follows: "*The degrees of freedom for a time-series model are the number of data points that are available to explain (or estimate statistically) the relationship between the explanatory variables and dependent variable, once the model has been specified. For example, if there are ten data points and four explanatory variables then there will be six data points available (i.e., ten minus four equals six) to estimate the relationship between the explanatory variables and the dependent variable. In general and assuming there are no other technical problems with the data, the more degrees of freedom available, the more reliable an estimated model will be*". HoustonKemp Expert Report, p 7. HoustonKemp goes onto find that (at p 11): "*Relevantly, DAE estimate the regressions using data for the nine year period, 2002 to 2010. This means for the regression for residential gas consumption per connection there are only five degrees of freedom with which to estimate the model parameters. Similarly for the industrial and commercial gas consumption per connection there are only six degrees of freedom...*".

to forecasting, as applied by Core Energy, represents the best approach to forecasting per customer consumption in the circumstances:[150]

> *In the event that econometric modelling of the available data does not provide a reasonable and reliable basis for forecasting gas demand, there remains the question of whether there is an alternate approach that is likely to produce more reasonable and / or reliable forecasts. In our opinion, in these circumstances trend analysis is likely to provide a more reasonable and / or reliable basis for producing forecasts of gas demand than forecasts based on DAE's econometric models. This is the approach adopted by Core, and accepted by DAE and the AER, for tariff V Small Business customers.*

Conclusion: Core Energy's trend approach to forecasting per customer consumption for tariff V residential and I&C customers is the best approach, given the limited data available.

3.5.2.5 Problem 4 – DAE's use of derived annual percentage changes results in forecasts substantially above its own regression model

239. DAE does not actually use the estimate customer gas consumption outputs from its regression models, but instead uses these estimates to derive an annual percentage change in per customer consumption for residential and I&C customers. Specifically DAE has:

- estimated the annual percentage change in tariff V residential and I&C per customer consumption for the period 2014 to 2020, based on the results of its econometric models
- applied the calculated percentage change from the regression analysis to expected gas consumption in 2014 within Core Energy's spreadsheet model, so as to derive the base case for forecast per customer consumption. The forecasts used by DAE/AER use the most recent historical data point (which was 2013 data) as the starting value for the forecast. As set out below, Core Energy's revised forecasts use the fitted value as derived from the historic trend, as the starting value for the forecast.

240. Applying the derived annual changes (not actual outputs) from DAE's regression model within the trend model prepared by Core Energy, has the effect of increasing the per customer consumption forecasts compared to that predicted from DAE's own regression models. In fact, most of the adjustment proposed by the AER to tariff V residential consumption is attributable to the inclusion of DAE's step change for economic activity (using SFD), with a lower impact attributable to the inclusion of a step change for GSP as a variable to forecast tariff V I&C consumption. This is shown in Figure 3–4 for tariff V residential per customer consumption.[151]

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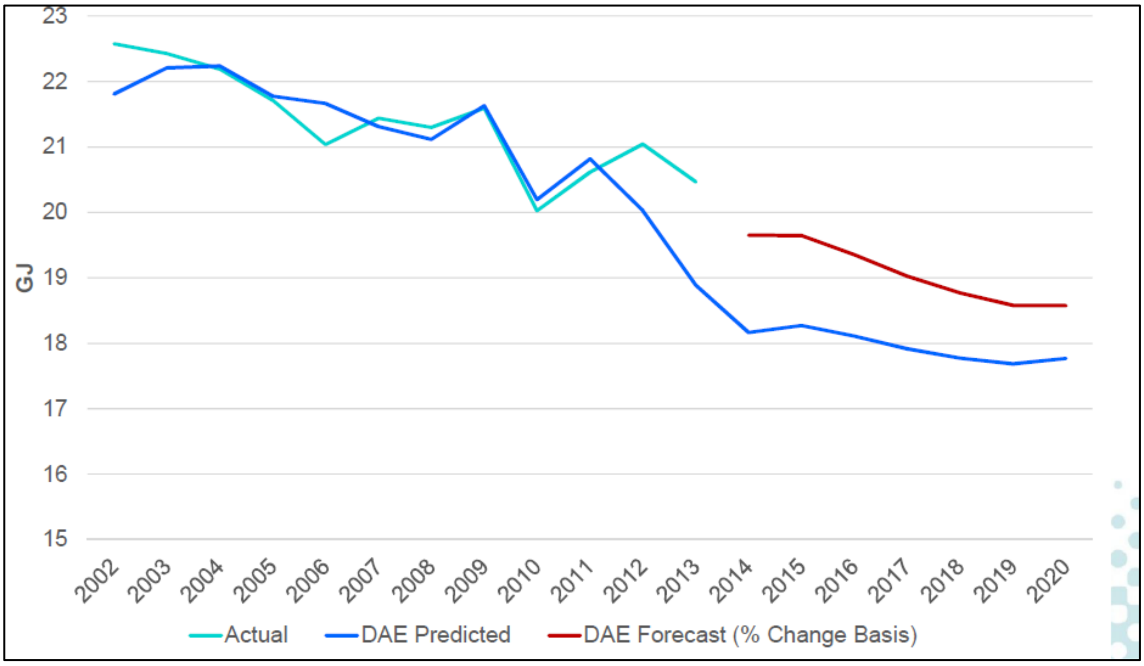
150 Frontier Expert Report, p 45.

151 Specifically, Figure 4 plots actual versus predicted residential per customer consumption using the DAE regression results for the period 2002 to 2013. For the period 2014 to 2020 the forecast of residential consumption per customer is plotted applying the regression model compared to the results estimated by DAE taking the percentage change and applying it to Core Energy's 2014 expected gas consumption. HoustonKemp Expert Report, p 16.

Figure 3–4: Comparison of historical data with DAE regression model predicted residential gas consumption per connection, 2002 to 2020



241. HoustonKemp observed the following about DAE's approach:[152]

> *By not using the regression model directly, DAE are implicitly assuming that there has been a shift in the regression modelled trend (upwards), without affecting the year-on-year change in consumption. DAE provide no explanation as to the basis for such a shift. This has the effect of arbitrarily increasing DAE's forecast of residential consumption per connection.*
>
> *Subject to my concerns about the reliability of the regression model, my opinion in the lack of any reasoning to support a structural shift in gas consumption in 2014, DAE should be forecasting residential gas consumption per connection directly from its regression model, rather than applying the resultant percentage change to expected consumption in 2014. This ensures that the forecast is consistent with the model that has been used to develop the relationships between the explanatory variables and historic gas consumption per connection.*

242. DAE do not explain why they do not use the results of their regression models but rather use derived annual percentage changes as inputs into Core Energy's model. Nor do DAE comment on the inconsistency between the results of the regression models, and the forecasts ultimately prepared for, and accepted by, the AER.

243. If DAE was of the view that it selected statistically meaningful parameters and used accurate and validated data, then it would be reasonable to assume that it considered the outputs of its own model were valid and could have been used to forecast consumption. For reasons considered above, it is unlikely that individual year-to-year estimated changes in per customer consumption derived from the results of the regression model will be any more reliable than the underlying results derived from the regression model. Moreover, the fact that DAE's regression models produce lower per customer connection forecasts, particularly for residential per customer consumption, is in and of itself good reason not to accept the AER final forecasts, which arbitrarily increase Core Energy's forecasts.

152 HoustonKemp Expert Report, p 17.

Conclusion: DAE's regression model results do not support a conclusion that Core Energy's forecasts underestimate per customer consumption. This is because the resultant forecasts derived directly from DAE's model – particularly, for residential per customer consumption– are below (not above) the Core forecasts. This means that in its own terms, DAE's regression model does not support a finding that Core Energy's model overestimates tariff V per customer consumption.

3.5.3 CONCLUSION ON DAE'S REGRESSION MODELS

244. JGN's review of the DAE analysis and data used, supported by expert opinion, confirms that DAE's regression models and application of the results from those models, does not provide reliable, and best estimates of forecast consumption for tariff V residential and I&C per customer consumption.

245. As demonstrated above, there are a series of serious model specification and data problems within DAE's econometric modelling for forecasting tariff V residential and I&C per customer consumption which results in statistically biased and spurious results. Critically, this means that the modelling cannot be relied upon to conclude that economic activity is a driver of per customer consumption for tariff V customers.

246. Correcting for the errors in DAE's approach does not provide for a more reliable ex ante model specification. In fact, none of the "corrected" regression models result in a reliable basis for deriving gas consumption forecasts. Given the inherent data limitations, Frontier and HoustonKemp have demonstrated that an econometric forecasting model is incapable of generating stable and reliable results.

247. This leads us to the conclusion that the application of the annual percentage change in the forecasts of per customer consumption derived from the regression models can be no more reliable than the absolute results generated by those models. Moreover, DAE's approach in:

- adding the annual percentage change in per customer consumption derived from the regression models within Core Energy's trend model,
- rather than using the lower per customer consumption forecasts deriving from those models themselves,

indicates DAE has arbitrarily increased, and therefore, overestimated, JGN's gas consumption forecasts over the next AA period.

248. In the above circumstances, the AER did not have a reasonable basis to reject Core Energy's forecasts and apply the flawed and spurious approach taken by DAE. Core Energy's forecasts continue to represent reasonably-based, best estimates in the circumstances.

3.6 JGN'S REVISED PROPOSAL

249. Core Energy's approach to revising its forecasts was to take into account the most recent input information and revise any related forecast assumptions to ensure that its forecasts are accurate and transparent and based on the best possible information available. Core Energy's revised demand forecasting model is provided at appendix 3.2. JGN's demand forecasts adopted for reference tariffs model is provided at appendix 3.3.

3.6.1 TARIFF V

250. The tables below summarise the net revisions to Core Energy's initial forecasts of per customer consumption, connections and total consumption.

Table 3–3: Movement in JGN tariff V consumption per connection forecasts, GJ.

	2014	2015	2016	2017	2018	2019	2020	Total (2015-2020)
Residential	0.24	0.11	0.02	-0.04	-0.11	-0.20	-0.30	-0.52
Small Business	17.26	-10.08	-7.68	-7.38	-7.60	-7.83	-8.16	-48.73
I&C	-29.36	1.54	6.94	5.08	1.93	-1.27	-4.45	9.77

Table 3–4: Movement in JGN tariff V connection forecasts, No.

	2014	2015	2016	2017	2018	2019	2020	TOTAL (2015-2020)
Residential	8,617	16,202	21,012	21,541	20,789	18,764	14,479	96,586
Small Business	39	79	122	167	215	266	321	1,092
I&C	583	631	678	721	765	811	858	3,832
Total	**9,239**	**16,913**	**21,812**	**22,429**	**21,770**	**19,842**	**15,658**	**101,510**

Table 3–5: Movement in JGN tariff V consumption forecasts, GJ.

	2014	2015	2016	2017	2018	2019	2020	TOTAL (2015-2020)
Residential	447,979	436,538	412,976	335,831	218,836	55,265	-159,940	862,969
Small Business	390,809	-211,852	-154,783	-144,740	-148,344	-152,944	-161,087	-761,898
I&C	-211,340	320,180	395,714	377,928	333,567	284,325	235,810	1,627,343
Total	**627,449**	**544,866**	**653,908**	**569,019**	**404,060**	**186,646**	**-85,217**	**1,728,415**

251. In summary, the movements in forecast consumption from Core Energy's original forecast are attributed to changes in both forecast per customer consumption and connections. Changes in per customer consumption have arisen from:

- updates for 2013-14 actual data in relation to per customer consumption for tariff V customers. A consequential effect of the inclusion of the 2013-14 actual data is that Core Energy have refined its approach to forecasts of per customer consumption—extrapolating the historic trend over the review period, rather than rebasing the forecasts so that its starting point is the most recent historical data point
- updates to the forecast of retail gas and electricity prices used in the analysis of price elasticity of consumption to account for the repeal of the *Clean Energy Act 2011* (Cth) (**Clean Energy Act**)

- updates to the IPART forecasts of retail electricity prices to reflect more recent estimates published by the AEMC in December 2014 (which also reflects the repeal of the Clean Energy Act). In making the updates for retail gas and retail electricity prices, Core revisited how it applied step changes from the extrapolated trend for price effects. In particular, Core applied the price differential, derived from difference between forecast impact of price and the historical impact of price to the forecast of per customer consumption.

252. Changes in tariff V connections have arisen from:

- updates for 2013-14 actual data for connections and disconnections
- updates to the forecasts for dwelling completions and residential connections to account for revised forecasts from independent data sources, BIS Shrapnel and HIA.

253. In cumulative terms, tariff V consumption has been revised upward by 1,728,415 GJ over the forecast period.

3.6.2 TARIFF D

254. Table 3–6 summarises the cumulative movement from Core Energy's original forecast of total tariff D forecast consumption to its revised forecast.

Table 3–6: Difference in JGN tariff D ACQ, MDQ and CD forecasts, GJ.

	2014	2015	2016	2017	2018	2019	2020	TOTAL (2016-2020)
ACQ	2,012,035	2,325,303	2,513,715	2,336,790	2,302,979	2,270,059	2,238,008	11,661,550
MDQ	45,490	15,110	14,380	12,410	12,674	12,704	12,704	64,872
CD	56,932	15,110	14,380	12,410	12,674	12,704	12,704	64,872

255. The movements in tariff D consumption forecasts are attributed to:

- new information provided by JGN relating to 2013-14 actual consumption, new connections and disconnections, as well as known changes in future gas consumption
- changes to assumed disconnections
- known changes in future gas consumption and transfers between tariff V and tariff D.

256. In summary, tariff D MDQ/CD has been revised upward by 64,872 GJ over the next AA period.

3.7 CONCLUSION: JGN'S REVISED PROPOSAL FORECASTS ARE REASONABLY-BASED AND THE BEST FORECASTS IN THE CIRCUMSTANCES

257. Establishing the best, reasonably-based demand forecasts is not only required under the NGR, but it is critical to afford JGN a reasonable opportunity to recover at least its efficient costs, and to support JGN's ability to prudently and efficiently invest in the network to promote the long-term interests of customers.

258. The AER's acceptance of DAE's demand forecasts does not achieve compliance with r 74(2) and does not provide JGN a reasonable opportunity to recover at least our efficient costs.

259. For reasons set out above, each departure made by DAE from Core Energy's approach contained clear and material errors—simply stated, DAE adopted selective and flawed forecast assumptions and derived unreliable statistical results. DAE then applied its erroneous forecasts within Core Energy's model and derived substantial and biased increases in estimated annual per customer consumption for certain customer types.

260. In contrast, Core Energy's trend-step change approach to estimating tariff V forecast per customer consumption over the next AA period does not contain the flaws reflected in DAE's regression approaches. Rather, Core Energy's approach represents a well-accepted methodology and clearly understood model specification, which incorporates relevant drivers of gas demand that have been validated through both quantitative and qualitative means. As concluded by DAE itself, "the approach adopted by Core was transparent, clear and generally sound in terms of methodology".

261. In the circumstances, Core Energy's forecasts should have been accepted by the AER. The forecasts meet the requirements of rule 74(2) in that they are reasonably-based, clearly better demand forecasts than those prepared by DAE, and overall the best estimates in the circumstances. Critically, Core Energy forecasts meet the requirements of the NGL when used in setting prices, in that they afford JGN a reasonable opportunity to recover at least its efficient costs as required under the RPPs.

4. CAPITAL EXPENDITURE

Box 4–1 Key messages – capital expenditure

Our 20-year asset strategy underpinned the capex programme we proposed in our initial proposal. It presented to customers multiple credible long-term service and price scenarios. Our customers told us they preferred to maintain our existing service levels and to provide a universal level of service to all our customers by 2020.[153]

The AER's draft decision for capex is 18 per cent lower than our proposal. We are very concerned that the AER has not tested the short and long-term consequences of this decision with customers, but is somehow confident to assert that this outcome is what customers would want. The AER has previously indicated that it would have difficulty testing the service implications of its decisions without consulting with customers.[154]

Expenditure to economically extend and expand the network reduces tariffs for all customers and helps ensure the relative price competitiveness of gas. We have no incentive to uneconomically expand the network—it simply damages the long-term success of our business because it creates a barrier to new connections and results in higher average gas prices.

Prudent and timely refurbishment and replacement expenditure delivers on our customers' stated preferences that safety remains our number one priority[155] and:

- maintains the quality of service that existing and potential new customers value and expect[156]
- avoids the need for catch-up expenditure and associated tariff shocks in future[157]
- avoids additional operating costs related to, for example, increased planned maintenance and unplanned activities such as emergency response and incident management.

The draft decision capex forecast for the 2015-20 AA period is materially lower than that proposed by JGN and, if confirmed in the final decision and implemented, will result in less preferable outcomes for customers. Our revised proposal broadly reflects the capex programme we initially proposed, and we further explain how this programme reflects the requirements of the NGR.

4.1 AER'S DRAFT DECISION

262. The draft decision gross capex forecast for the 2015-20 AA period is 18 per cent below the level we proposed – $941.9 million compared with $1,148.5 million ($2015). The composition of the difference is shown in Table 4–1.

153 JGN, *2015-20 access arrangement information - appendix 1.4*, 30 June 2014, section B.

154 AER, *AER Annual Report 2013-14*, p 16.

155 JGN, *2015-20 access arrangement information - appendix 1.5*, 30 June 2014, section B.

156 Ibid.

157 JGN, *2015-20 access arrangement information - appendix 1.5*, 30 June 2014, section B.

Table 4–1: Comparison of JGN's proposed and AER's alternative forecast capex requirements for the 2015–20 AA period ($million, $2015, unescalated direct costs, excluding overheads)

Category	JGN's initial proposal	AER's alternative forecast	Difference ($millions)	Difference (%)
Market expansion	384.1	299.6	(84.6)	(22.0%)
Capacity development	95.0	83.4	(11.6)	(12.2%)
Mains and service renewal	62.3	59.1	(3.2)	(5.1%)
Facilities renewal and upgrade	124.1	98.4	(25.7)	(20.7%)
SCADA	9.8	3.2	(6.5)	(66.8%)
Meter renewal and upgrade	163.9	126.9	(37.0)	(22.6%)
Government authority work		[c-i-c]		
Mine subsidence	1.9	1.9	(0.0)	(0.0)
IT	131.6	131.7	0.1	0.1%
Other - non-distribution	26.8	26.8	0.0	0.0%
Overheads	144.4	109.0	(35.4)	(24.5%)
Related party margin		[c-i-c]		
Gross total capital expenditure	**1,148.5**	**941.9**	**(206.7)**	**(18.0%)**
Contributions	17.3	22.4	5.1	29.6%
Asset disposals	0.8	0.8	0.0	0.0%
Net total capital expenditure[(b)]	**1,130.4**	**918.6**	**(211.8)**	**(18.7%)**

Source: AER's draft decision Table 6-3.

263. The difference between JGN's proposal and the AER's alternative forecast is the product of a range of factors including AER errors and misunderstandings, and differences of opinion on key inputs.

4.2 JGN'S RESPONSE TO THE DRAFT DECISION

264. JGN does not accept the AER's alternative capex forecast of $941.9 million ($2015) for the 2015-20 AA period.

265. JGN has developed a revised capex forecast which takes into account the matters raised by the AER in its draft decision as well as updated and more recent historical information where that is relevant. The revised capex forecast is also consistent with other aspects of JGN's revised proposal such as the updated demand forecast described in chapter 3. Our revised capex model is provided as appendix 4.1. Table 4–2 summarises JGN's revised capex forecast.

Table 4–2: Comparison of JGN's proposed and AER's alternative capex forecast and JGN's revised proposal for the 2015–20 AA period ($million, $2015, unescalated direct costs, excluding overheads)

Category	JGN's initial proposal	AER's alternative forecast	JGN's revised proposal	Difference – JGN revised vs. AER alternative ($millions)
Market expansion	384.1	299.6	392.3	92.8
Capacity development	95.0	83.4	95.6	12.2
Mains and service renewal	62.3	59.1	61.6	2.5
Facilities renewal and upgrade	124.1	98.4	120.8	22.4
SCADA	9.8	3.2	9.6	6.4
Meter renewal and upgrade	163.9	126.9	168.8	41.9
Government authority work		[c-i-c]		
Mine subsidence	1.9	1.9	2.0	0.1
IT	131.6	131.7	135.6	3.9
Other - non-distribution	26.8	26.8	26.4	(0.3)
Overheads	144.4	109.0	126.8	17.8
Related party margin		[c-i-c]		
Gross total capital expenditure	**1,148.5**	**941.9**	**1,144.3**	**202.4**
Contributions	17.3	22.4	25.5	3.1
Asset disposals	0.8	0.8	0.8	(0.0)
Net total capital expenditure[(b)]	**1,130.4**	**918.6**	**1,118.0**	**199.4**

4.3 MARKET EXPANSION

266. Growing our customer base is an important component of JGN's strategy to contain network charges and thereby maintain the relative price competitiveness of gas. It is not in our interests to damage the gas brand by overstating our connection unit rates. New economic connections have always been the foundation of our business's success—we have always been a private network only interested in expanding where it is economic to do so, and not into uneconomic supply locations. New economic connections become even more important as natural gas competes more aggressively with other fuels.

267. JGN's customers accepted the fundamental relationship between new economic connections and their long-term interests, and understood the need to expend capital to achieve growth.[158]

268. We encourage the AER to step back and consider the competitive discipline we already face when we propose connection unit rates for AER assessment.

158 JGN, *2015-20 access arrangement information - appendix 1.4*, 30 June 2014, p 32.

4.3.1 AER'S DRAFT DECISION

269. The AER's alternative forecast for market expansion capex differs substantially from JGN's proposal for a number of reasons, some of which are the result of AER error or misunderstanding, while others reflect a difference of opinion on key inputs. The draft decision:

- uses historically observed unit rates as the basis for its forecast[159]
  - those rates do not reflect JGN's current outsourcing arrangements and, in particular, are materially lower than the associated contractor activity unit rates which the AER accepts are efficient[160]
  - as a result:
    - does not differentiate between routine and non-routine connections which have very different cost structures
    - does not recognise the distinct costs of meter data loggers (**MDLs**) associated with new medium density connections[161]
- adopts its consultant's (DAE) forecast of new connection numbers which is lower than what JGN proposed[162]
- forecasts new connections without including the additional connections that will be generated by the marketing opex step change which the AER has approved[163]
- disallows the margin that is paid to Zinfra in respect of work in the southern region of the JGN network, apparently without regard to material that JGN had provided to explain JGN's outsourcing arrangements and justify the charges under those arrangements[164]
- does not accept JGN's forecast ratios of length of mains, and numbers of services and meters per new connection.[165]

4.3.2 JGN'S REVISED PROPOSAL

270. In JGN's view the AER's forecast of market expansion capex has not been arrived at on a reasonable basis and is not the best forecast or estimate possible in the circumstances.[166] JGN's revised market expansion capex forecast is set out in Table 4–3. The market expansion unit rate derivation model is provided as appendix 4.2.

159 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-25.

160 Ibid, p 6-47.

161 Ibid, p 6-26.

162 Ibid, p 6-23 and Table 6-9.

163 Ibid, p 7-23.

164 Ibid, p. 6-26.

165 Ibid, p. 6-24.

166 NGR, rule 74.

Table 4–3: Market expansion capex – $millions, $2015 [167]

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	86.47	91.13	91.49	90.34	91.49	450.91
AER's draft decision	68.23	70.96	69.70	69.22	70.27	348.37
JGN's revised proposal	92.72	92.76	90.99	89.81	87.38	453.66

271. As in our initial proposal, JGN has forecast the routine and non-routine elements of market expansion capex separately in this revised proposal.

4.3.2.1 Forecasting method – construction unit rates for routine connections

272. A majority of connections involve just a service and a meter and perhaps a typical mains extension. These are classified as routine. Other, more complex, connections are classified as non-routine as described in section 4.3.2.3.

273. For reference, Table 4–4 compares the fully-costed construction unit rates for routine connections in our initial proposal with those in our revised proposal, and the actual rates for 2013-14.

Table 4–4: Fully-costed construction unit rates for routine connections compared – $2014

Categories	Initial proposal	Revised proposal	2013-14 actual
Services	**$/connection**	**$/connection**	**$/connection**
E to G		[c-i-c]	
New homes			
I&C tariff			
Medium density			
Mains	**$/m**	**$/m**	**$/m**
E to G		[c-i-c]	
New homes			
I&C tariff			
Medium density			
Meters	**$/customer**	**$/customer**	**$/customer**
E to G		[c-i-c]	
New homes			
I&C tariff			
Medium density - meter			

167 All amounts in this table and corresponding tables in sections 4.4 to 4.8 and 4.10 to 4.12 inclusive are "gross capex" that is, gross capex before customer contributions and including cost escalation and allocated overheads. The exception is section 4.9 (government authority work), where the amounts are net of contributions.

Amounts in the "JGN initial proposal" rows are drawn from relevant tables in JGN's initial proposal.

Amounts in the "AER draft decision" rows are drawn from the relevant table in the spreadsheet named "AER - draft decision JGN - capex - November 2014 - CONFIDENTIAL.xlsx".

Categories	Initial proposal	Revised proposal	2013-14 actual
Medium density - MDL		[c-i-c]	

274. As in our initial proposal, JGN continues to forecast the unit cost of construction for routine connections separately for the four types of routine connection:

1. electricity to gas (**E to G**) conversions (connection of an existing all electricity premise to gas)
2. new homes (new estate areas)
3. medium density (high rise and villa-type premises)
4. I&C tariff (small to moderate-sized business customers)

275. This division reflects the very different work generally required to connect each customer type, in terms of requirements for mains, services and meters. As a result, the costs of mains, services and meters for routine connections are forecast separately for each type. JGN's revised forecasting method for construction unit rates for routine connections reflects:

- the use of the most recent (RY14) data, where historical data is used as part of the unit rate forecasting method
- fully-costed unit rates that reflect outsourcing arrangements which the AER considers efficient,[168] including relevant contract unit rates applied to an activity mix which takes into account actual activities for the four completed years of the current AA period (RY11 to RY14)
- inclusion of a performance-based margin on the management fee paid to Zinfra for the management services it provides in the southern region (see section 4.14.3)
- the removal of direct overheads, which are proposed to be forecast separately using a base-step-trend approach, instead of being embedded in direct costs (see section 4.14.2)
- ratios of mains lengths, service numbers and meter numbers per new connection that are the averages of observed ratios for the four completed years of the current AA period (RY11 to RY14)
- MDL costs for new medium density connections being forecast separately
- energisation costs.

Mains and services unit rates

276. For routine mains and services, the unit cost of construction is made up of six components: contractor, restorations, materials, management fee, internal labour, and quoted works.

- *contractor*—the draft decision rejected JGN's proposed contractor unit rates because they were based on only one year of actual activity mix data.[169]
  - the unit rates in the revised proposal are based on activity mix data for the four completed years of the current AA period (RY11 to RY14)[170]

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168 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-47.

169 Ibid, pp 6-21, 6-22 and 6-24.

170 The AER accepts that "at least three years of data would adequately capture differences in composition differences across time": *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-24.

   - contracted unit rates, which the AER accepts are efficient,[171] are then applied to the four-year average activity mix.

- *restorations and materials*—the forecasts for the restoration and materials components of the mains and services unit rates have been derived from costs of those components for the four years of the current AA period to RY14.
- *Management fee (including management margin), internal labour and quoted works*[172]—these costs are all based on actual costs for RY14. JGN is unable to use a longer period as these items either did not exist in earlier years or have substantially changed with the commencement of the new outsourcing arrangements in the northern and southern regions from July 2013.[173]

277. The above is summarised in Table 4–5.

Table 4–5: Mains and services – basis of unit rates

Component	E to G	New homes	Medium density	I&C tariff	I&C contract
Contractor	4 year average of volume mix **x** current contract rates				4 year average
Restorations	4 year average				
Materials	4 year average				
Management fee(1)	RY14 actuals				
Internal labour	RY14 actuals				
Quoted works	RY14 actuals				

(1) The Management fee component in this table reflects both the Management Fee and Management Margin payable to Zinfra for management services in the southern region under the Field Services Agreement (**FSA**) between Jemena Asset Management and ZNX(2).

278. Contractor costs are the largest single component of the unit cost of mains and services. We compared the average contractor rates for mains and services that result when four years of historical activity data is used against:

- the rates that we submitted in our initial proposal (based on one year's data)
- the rates that would result if averages were based on three years of historical activity data
- the actual rates observed for 2013-14,

and found that the average contractor rates are relatively insensitive to the period over which the activity mix is calculated: one, three or four years—see Table 4–6. We therefore consider that the average for the first four years of the current AA period is a reasonable basis for forecasting contractor unit rates.

171 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-47.

172 Quoted works are those activities that are not covered by the schedule of rates in the FSA for which the contractor quotes, including activities such as traffic control, night works, works on major roads, etc. By separately quoting these works the base unit rate costs are kept lower and more reflective of average type of activities.

173 As explained in: JGN, *2015-20 access arrangement information*, 30 June 2014, appendix 4.1

Table 4–6: Sensitivity testing of contractor unit rates – $2014

Categories	Initial proposal	Three year average	2013-14 actual	Four year average (our revised proposal)
Services	$/connection	$/connection	$/connection	$/connection
E to G	[c-i-c]			
New homes				
I&C tariff				
Medium density				
Mains	$/m	$/m	$/m	$/m
E to G	[c-i-c]			
New homes				
I&C tariff				
Medium density				

279. This analysis also addresses the AER's concern that one year's data was an inadequate basis for forecasting.[174] While the activity mix may vary from year to year that variation does not appear to have a material effect on average unit rates.

Meter unit rates

280. For meters, the unit cost of construction has seven components: contractor, materials—gas meters, materials—hot water meters, materials—MDLs, internal labour, quoted works, and energisation cost.

- *contractor*—the unit rates in the revised proposal are based on the average of the rates for the four years of the current AA period to RY14
  - unlike the mains and services contractor costs, the meter contractor costs have not changed with the new outsourcing arrangements. Therefore the average of the costs for the current AA period is reflective of historical trends and appropriate as a forecasting basis. It should be noted that using historical costs will also account for any variation in the mix of activities
- *material cost for gas meters*—is based on costs for the four years of the current AA period to RY14
  - the use of the four year period smooths any variability in the mix of different meter types between years, particularly in the I&C tariff category
  - these costs include costs for the meter, regulator, meter bar, meter control valve and any consumables
- *material cost for hot water meters*—is based on the latest tendered rates for hot water meters
  - these costs reflect JGN's current technical requirements which were updated following product failures identified earlier in the current AA period
- *material cost for MDLs*—has been based upon the latest purchase costs for MDL.
  - the forecast volume of MDLs is based on the average number of customers per MDL for medium density connections over the four years to RY14 (the average is approximately 21 customers per MDL)

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174 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-24.

- *internal labour and quoted works*—have been based on RY14 actuals, consistent with the method applied to mains and services construction unit rate
- *energisation cost*—since JGN submitted its initial proposal there has been a change of circumstances in that JGN now expects that new Retail Market Procedures will take effect in NSW (and the ACT). The new Retail Market Procedures will provide for business-to-business (**B2B**) and business-to-market (**B2M**) processes in NSW (and the ACT) to be harmonised with those in other jurisdictions.[175] As part of those changes JGN will also be subject to new obligations as documented in Participant Build Pack 5 of the Gas Interface Protocol which details the technical standards and business processes that enable retail and distribution businesses and AEMO to transfer information between market participants' systems, in accordance with the new Retail Market Procedures.[176] Relevantly, Appendix G of Build Pack 5 includes the specification for the meter fix (MFX) service request which has two preconditions, the second of which is:

  Precondition - (B): The MIRN exists and the status is "Unclaimed" and the Meter Status is "plugged". A customer requests the retailer energise their site.

  NOTE 2: A SCR is NOT required in this case.

  NOTE 3: Precondition B is used for all Unclaimed supply points.

  where "unclaimed" means that there is no retailer responsible for the supply point in market systems.

  It follows from this precondition, and note 3 in particular, that JGN must leave the meter plugged when it installs a meter and the supply point is unclaimed—the Gas Interface Protocol does not contemplate a situation where the meter is unclaimed and unplugged. In the case where a physical connection is established but the meter is left plugged, JGN must then return to the site to remove the plug and energise the premises when it receives a retailer's request or evidence of a relevant retail contract in place in relation to the premises. JGN will incur additional costs in making those return visits (**the energisation cost**).

  Under Part 12A of the NGR JGN must establish a physical connection to its network if/when it receives an application for connection and JGN's connection offer is accepted. Part 12A provides for three categories of connection applicant:

  - a retail customer (i.e. a person to whom gas is sold for premises by a retailer)
  - a retailer or other person acting on behalf of a retail customer
  - a real estate developer.

  Of these categories, the first two by definition require a relationship with a retailer to have been established, so that a retail contract will be in place at or before the time the connection application is made. Real estate developers are the only class of connection applicant that will not (or may not) have an established relationship with a retailer at the time they request a connection. Therefore, it is this category of connection that will give rise to unclaimed sites. Accordingly, the unit rates for new connection meters in the new homes and medium density categories (only) include provision for the energisation cost (i.e. the cost of a technician to attend the relevant site, subsequent to the physical connection being established, to remove the plug from the meter, to allow gas to flow through the connection).

175 The related "B2B harmonisation" IT capex project is described in section 4.10.2.

176 The Retail Market Procedures require market participants to comply with the Gas Interface Protocol.

For the purpose of forecasting the unit rates, JGN has:

- assumed that the percentages of new home and medium density connections that will incur this cost are the four year historical averages of the percentages of new home and medium density connections where applications have been made direct to JGN (without a retailer in place) and that have been allocated to a retailer through the current panel arrangements. The percentages are 41.7 per cent for new homes and 100 per cent for medium density
- in its modelling, included the energisation cost component within the contractor rate given that it is primarily a contractor cost.

281. The above is summarised in Table 4–7.

Table 4–7: Meters – basis of unit rates

<table>
<tr><th>Component</th><th>E to G</th><th>New homes</th><th>Medium density</th><th>I&C tariff</th><th>I&C contract</th></tr>
<tr><td>Contractor (1)</td><td colspan="4">4 year average</td><td rowspan="7">4 year average</td></tr>
<tr><td>Materials—gas meters</td><td colspan="4">4 year average</td></tr>
<tr><td>Materials—hot water meters</td><td colspan="4">4 year average</td></tr>
<tr><td>Materials—MDLs</td><td colspan="4">RY14 actuals</td></tr>
<tr><td>Internal labour</td><td colspan="4">4 year average</td></tr>
<tr><td>Quoted works</td><td colspan="4">4 year average</td></tr>
<tr><td>Energisation cost (1)</td><td>Nil</td><td colspan="2">Unit rate x 4 year average percentage uncontracted</td><td>Nil</td></tr>
</table>

(1) As noted previously, JGN has included the energisation cost as part of the contractor rate in its modelling.

4.3.2.2 Forecasting method – market expansion capex for routine connections

282. The cost of mains, services and meters per new connection of a particular type is determined by multiplying the relevant construction unit rate by the applicable ratio—metres of main per connection; services per connection; and meters per connection—for that connection type.

283. Table 4–8 compares the ratios of metres of main, and numbers of services and meters per new connection in JGN's initial proposal with the ratios in the AER's draft decision and in JGN's revised proposal.

Table 4–8: Connection ratios

Component	E to G	New homes	Medium density	I&C tariff
JGN's initial proposal				
Metres of main per connection	3.3	15.0	1.9	19.0
Services per connection	0.9	1.0	0.1	0.7
Meters per connection	1.0	1.0	1.0	1.0
AER's draft decision				
Metres of main per connection	4.0	15.9	1.3	14.4
Services per connection	0.9	1.0	0.1	0.6

Component	E to G	New homes	Medium density	I&C tariff
Meters per connection	1.0	1.0	1.0	1.0
JGN's revised proposal				
Metres of main per connection	4.9	16.9	0.9	8.9
Services per connection	0.9	1.0	0.1	0.5
Meters per connection	1.0	1.0	1.0	1.0

284. In each case, the ratio that JGN has adopted in the revised proposal is the average of the observed ratios for the four years of the current AA period to RY14. This takes into account the most recent information and therefore presents the best estimate in the circumstances.

285. The cost of mains, services and meters per new connection for each connection type is then multiplied by forecast connection numbers for each connection type to generate a forecast for market expansion capex.

286. We have adopted new connection volumes that are consistent with JGN's updated connections forecast (refer chapter 3).

4.3.2.3 Forecasting method – market expansion capex for non-routine connections

287. As in the initial proposal, JGN continues to forecast the capex for routine and non-routine new connections separately. As we stated in our response to AER information request no 40:

> *A large proportion of connections involve just a service and a meter and perhaps a short mains extension. These are classified as routine. Non-routine connections are those costing more than $200k or that involve, for example, steel work, connection of a large/contract customer, installation of secondary regulator sets/Cocons, directional drilling or boring. As a result there is a substantial difference between the unit costs of routine and non-routine connections. Volumes are also very different with non-routine connections making up less than 15 per cent of the total. Given these differences, it is good practice to forecast routine and non-routine connections.*[177]

Non-routine tariff connections

288. The cost of the mains component for non-routine tariff connections is forecast separately for each type of tariff connection except E to G[178] i.e. new homes, medium density and I&C tariff, as follows:

- the length of mains for non-routine connections of each type is forecast by applying the historically observed average percentage of mains length for non-routine connections of that type to the forecast length of mains for new connections for that type
- the cost of the mains component is then forecast by multiplying the forecast length of mains by the historically observed average cost per metre of main for non-routine connections of that type.

289. The cost of associated services and metering components is determined by applying the relevant construction unit rates described previously.[179]

177 JGN, *Response to connections question, AER Information request 40*, 22 October 2014, p. 1.

178 Non-routine connections do not arise for E to G.

I&C contract connections

290. The cost of I&C contract connections is forecast as follows:

- the mains and services components are the average cost of each type for the four years of the current AA period, to RY14
- the meters component is the average cost of I&C contract meters for the four years of the current AA period to RY14
  - this average includes the costs of design, procurement of components (meters, regulators, valves), fabrication and installation of the meter set and the Metretek systems for these customers.

4.3.3 SUMMARY

291. JGN's revised forecast for market expansion capex:

- uses unit rates that reflect JGN's current outsourcing arrangements
- forecasts the cost of routine and non-routine connections separately, consistent with their very different cost structures
- recognises the distinct costs of MDLs associated with new medium density connections[180]
- reflects Core Energy's updated forecast of new connections (see section 3.6) and includes the additional connections that will be generated by the marketing opex step change which the AER has approved
- includes margin that is payable to Zinfra in respect of work in the southern region of the JGN network (see section 4.14.3)
- uses updated forecast ratios of length of mains, and numbers of services and meters per new connection.

292. JGN's revised forecast of market expansion capex has been arrived at on a reasonable basis and is the best forecast in the circumstances in that:

- it is built using methods that are fit for purpose and properly reflects current best views of key inputs
- where relevant, it is based on observed historical information and costs which are efficient.

4.4 CAPACITY DEVELOPMENT

293. Capacity development is necessary to support demand growth, to accommodate changing patterns of demand, and to ensure that service quality is maintained for existing customers.

4.4.1 AER'S DRAFT DECISION

294. The AER accepts 82 of 93 capacity development projects and their proposed costs as prudent and efficient.[181] The remaining 11 projects are rejected for a variety of reasons.[182]

179 In terms of JGN's forecast capex model, the total amount for services and meters associated with non-routine connections is included as part of the corresponding amount for routine connections.

180 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-26.

4.4.2 JGN'S REVISED PROPOSAL

295. Table 4–9 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for capacity development capex.

Table 4–9: Capacity development capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	21.29	21.78	27.30	22.76	18.87	111.99
AER's draft decision	20.01	19.65	25.23	18.80	13.15	96.84
JGN's revised proposal	20.37	21.21	26.88	22.85	18.59	109.90

296. JGN's revised proposal is unchanged in relation to the 82 projects that the AER accepts as prudent and efficient.

297. In terms of the 11 projects that the AER has rejected, JGN's revised proposal includes nine of them, that is, all except the Sydney, Park Street CDP and the Alexandria-Waterloo interconnection.

- *Sydney, Park Street*—this project is no longer included in the capex programme for the 2015-20 AA period because JGN initiated the interconnection in late 2014 for completion in 2015. Since the initial capex forecast was prepared, JGN has received a request for new load from a customer in the affected area of the CBD. The interconnection is required now in order to provide the capacity required by the customer.
- *Alexandria-Waterloo interconnection*—as noted by Sleeman Consulting, this project was contingent on the timing of the Darlington to Alexandria secondary main.[183] Since the initial capex forecast was prepared, JGN has continued to progress discussions with the authorities responsible for the railway crossings required by the Darlington to Alexandria project. Based on these more recent discussions, JGN now has a higher level of confidence that that project will be completed in time. Accordingly, the revised proposal does not include provision for the Alexandria-Waterloo interconnection.

298. JGN does not accept Sleeman Consulting's conclusions in relation to the nine projects that JGN has included in its revised proposal. Broadly speaking, expenditure is required on the projects during the 2015-20 AA period for one or more of the reasons set out in Table 4–10:

Table 4–10: Common themes relevant to rejected CDPs

Reason	Examples of relevant projects
The project is in the Sydney CBD where lead times can be significant	Haymarket, Surry Hills and Kent and Druitt Streets
Project timing is sensitive to changes in demand in the location	CBD projects. The Sydney, Park Street project is an example. Scheduled for 2018-19 and 2019-20 in JGN's initial proposal, the project will now be completed in 2015 to meet a request for new load from a single customer in the affected area.

181 Ibid, p 6-27.

182 Ibid, pp 6-29 and 6-30.

183 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Capacity Development and Facilities Renewal and Replacement, Report to Australian Energy Regulator*, September 2014, para. 2.13(ix).

Reason	Examples of relevant projects
Early planning and investment in part or all of a project is required e.g. to acquire land or negotiate rail crossings	Unanderra
The project will provide security of supply to commercial customers	Haymarket, Surry Hills, Kent and Druitt Streets and Rockdale
The project provides long-term capacity in an area that is targeted for growth	Haymarket, Surry Hills, Kent and Druitt Streets and Rockdale
The project is required to ensure timely provision of capacity to meet organic growth from existing customers, E to G conversions and/or new homes developments	Woolooware, Hoxton Park, Kincumber, Unanderra and Bradbury
The project addresses anticipated low supply pressures	Woolooware, Hoxton Park, Kincumber and Bradbury

299. If these projects do not proceed, reliability and quality of service in the affected areas will be below the accepted standard with adverse consequences for customer experience. Opportunities for new customers to connect could also be limited or missed.

300. Additionally, the lower reliability of supply for these areas will lead to higher levels of opex, primarily through the need to respond to loss of supply and poor supply incidents.

301. Our detailed responses in relation to the 11 rejected projects are set out in appendix 4.3.

4.5 MAINS AND SERVICES RENEWAL

4.5.1 AER'S DRAFT DECISION

302. The AER accepts JGN's proposed mains and services renewal projects as prudent and efficient, with the exception of three projects in the Wollongong/Coniston area.[184] In the case of Wollongong/Coniston projects the AER is not satisfied that the proposed cost is efficient and has reduced the cost of those projects by 15 per cent in its alternative forecast.[185]

4.5.2 JGN'S REVISED PROPOSAL

303. Table 4–11 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for mains and services renewal capex.

Table 4–11: Mains and services renewal capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	14.92	19.33	15.37	10.51	11.99	72.13
AER's draft decision	14.46	18.59	14.27	9.90	11.41	68.62
JGN's revised proposal	14.21	18.66	14.97	10.65	12.34	70.84

184 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-31.

185 Ibid, p 6-32.

304. JGN accepts the AER's draft decision with the exception of the proposal to reduce the forecast unescalated direct cost of the Wollongong/Coniston projects by 15 per cent.

305. The AER's position is informed by four paragraphs in the Sleeman Report:

> *3.2 JGN has the capacity to undertake the proposed [mains and services renewal] projects, as presently scheduled.*
>
> *3.3 I consider Capex associated with the projects identified as 'high importance' in Figure 1 meets the Criteria. I consider these projects to be of high importance in view of the potential for public endangerment if they are not completed. It would be imprudent for JGN to not undertake these projects in a timely manner.*
>
> *3.4 Subject to paragraph 3.5 below, I consider Capex associated with the projects identified as 'medium importance' in Figure 1 meets the Criteria. I consider these projects to be of medium importance since it is prudent that they be completed but the timing of completion is not critical.*
>
> *3.5 I consider the forecast Capex for the Wollongong/Coniston rehabilitation project (OB C411-33, 34 & 35) to be **too high**. I understand the basis of the forecast Capex is an average of indicative costs provided by selected parties. The project has not yet been tendered. I recommend the Capex provision for the project be reduced by 15%, giving a cost per km of around $200,000* (emphasis added).[186]

306. Although not stated in Sleeman Consulting's report, we understand that the view that the costs of the Wollongong/Coniston projects are too high may be based on the relative position of Wollongong/Coniston on two graphs in the engineering assessment for the projects.[187] In addition, while $200,000 per kilometre is within the range of values for the projects plotted in the second of the two graphs, Sleeman Consulting does not provide any justification to support the apparent conclusion that $200,000 per kilometre of main is a relevant benchmark cost for the Wollongong/Coniston projects.

307. We accept that the graphs are included in material before the AER, however we note that the plotted values are not in constant dollars e.g. $2013, and that the values for earlier projects do not reflect current costs. Moreover, as discussed below, metrics such as cost per customer and cost per meter of main depend strongly on project-specific factors.

308. JGN does not accept that its proposed cost for the Wollongong/Coniston projects is inefficient.

The basis of estimation

309. The direct cost of a particular rehabilitation project is driven principally by the number of services (which is closely related to the number of customers[188]) and the length of mains and their diameter (which affects the cost per metre of main). Other factors that contribute to differences in costs between projects include:

- differences in the proportions of inserted and newly-laid mains

186 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Meter Renewal and Upgrade, Mains and Services Renewal and SCADA, Report to Australian Energy Regulator*, September 2014, paras. 3.2 to 3.5.

187 JGN, *Mains Integrity Assessment: Wollongong/Coniston 7kPa Rehabilitation Project*, May 2014, p. 68 of 86. (Submitted with the AA RIN in a file named C411 - 33, 34 & 35 Wollongong Coniston 7kPa Rehabilitation Project EA May 2014.pdf.)

188 As noted in Table 4–8, the number of services per connection (or customer) varies according to the type of connection and is less than one on average, particularly for medium density connections.

- the project environment which will affect costs in categories such as traffic management and restoration costs
- related/consequential activities such as connecting the rehabilitated system to existing infrastructure and the upgrade/modification of pressure regulating equipment that feeds the new mains.

310. The cost estimates for all rehabilitation projects included in JGN's initial proposal have several important features in common:

- the numbers of customers affected and the numbers of services and length of mains to be rehabilitated have been sourced on a consistent basis from asset records
- the costs of all of the projects are estimated using the same estimation model which draws on a common set of unit costs for mains and services and unit rates for ancillary activities such as traffic management and restorations
- the project estimates take account of project-specific differences. They:
  - provide for required lengths of appropriately sized mains—newly-laid and inserted
  - provide for related requirements such as tying the new mains in to existing mains and the upgrade/modification of pressure regulating equipment that feeds the new mains
  - take account of environmental factors that affect elements such as traffic management and restoration costs.

311. Given these common features, it follows that differences in total project costs and any variation in metrics such as total cost per km of main or total cost per customer between projects are the result of different project characteristics.

Comparing the Kensington and Wollongong/Coniston projects

312. The effects of cost drivers on project metrics can be seen by comparing the Kensington and Wollongong/Coniston projects.

Table 4–12: Kensington and Wollongong/Coniston projects compared

	Direct unescalated cost $,000, $2013 (1)	Number of customers	Total metres of main	Customer density – customers per km of main	Cost per customer, $2013	Cost per metre of main, $2013
	A	B	C	B/C*1,000	A/B*1,000	A/C*1,000
Kensington Stage 4	3,451	1,165	9,330	125	2,962	370
Kensington Stage 5	2,035	639	6,538	98	3,185	311
Kensington Stage 6	1,700	441	4,900	90	3,854	347
Wollongong Stage 2b	1,783	347	9,150	38	5,139	195
Wollongong Stage 2c	1,303	291	6,000	49	4,477	217
Wollongong Stage 2d	2,141	377	9,200	41	5,680	233

(1) JGN, *AAI appendix 06.04 - JGN capex forecast model - CONFIDENTIAL.xlsb* – Calc|Capex (FY) sheet.

313. The differences in cost per customer and cost per metre of main between the two groups of projects are principally the result of the very different customer densities in the two areas. Noting that the cost of rehabilitating the service is essentially a fixed cost per customer [188]:

- the higher cost per customer in Wollongong/Coniston is consistent with the lower customer density in that area—all else equal, a lower customer density means a greater length and cost of main per customer
- the higher cost per metre of main in Kensington is consistent with the higher customer density there—all else equal, a higher customer density means a greater number and cost of services per metre of main.

314. Other factors that will contribute to differences in metrics are:

- *the proportion of newly-laid main*—laying new mains is more costly than insertion and the proportion of new mains is higher in Wollongong/Coniston (2.1 per cent of total length) than in Kensington (0.8 per cent of total length)
- *environmental factors*—restoration costs per customer and per meter of main and traffic management costs per metre of main are higher in Kensington (a relatively densely populated Sydney suburb) than in Wollongong/Coniston.

Summary

315. Given that JGN's proposed costs for rehabilitation projects are produced by a cost estimation method with the common features described above, it follows that differences between proposed total project costs and metrics such as total cost per km of main or total cost per customer for the projects are the result of differences in project characteristics. JGN's cost estimates account properly for those different characteristics.

316. The proposed cost of the Wollongong/Coniston projects is consistent with the costs of other rehabilitation projects and is efficient. The projects are required to bring the service quality for these customers up to the norm for the network and, without them, the area will have an increased maintenance burden.

4.6 FACILITIES RENEWAL AND REFURBISHMENT

4.6.1 AER'S DRAFT DECISION

317. The AER approves JGN's proposed expenditure for facilities renewal and refurbishment with the following exceptions:

- the AER accepts Sleeman Consulting's view that:
  - the Zentec Designs and Wilton to Horsley Park trunk pipeline in-line inspection projects are not justified[189]
  - coal seam gas (**CSG**) will not enter the JGN network at Newcastle in material quantities within the period to 2020 so that six proposed facilities upgrade projects on the Northern Trunk to accommodate CSG from the north will not be required during the 2015-20 AA period[190]
- the AER considers that total planning costs (**TPC**) should be treated as an overhead cost rather than as projects under facilities renewal and refurbishment as proposed by JGN.[191]

189 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, pp 6-34 and 6-35 and Table 6-14.

190 Ibid, p 6-34.

4.6.2 JGN'S REVISED PROPOSAL

318. Table 4–13 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for facilities renewal and refurbishment capex.

Table 4–13: Facilities renewal and refurbishment capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	28.67	25.52	31.75	33.94	24.82	144.70
AER's draft decision	26.26	22.13	23.45	23.89	18.63	114.36
JGN's revised proposal	27.31	24.22	29.74	32.89	24.69	138.86

4.6.2.1 Disallowed projects

Zentec designs

319. Since submitting its initial proposal in June 2014, JGN has reviewed the design of the affected stations, including by obtaining a report from independent external engineering consultants. Having reviewed that advice, JGN has now determined that the capex provision for these works is no longer required. Accordingly, no provision for this project is included in the revised proposal.

In-line inspection of the Wilton to Horsley Park trunk pipeline

320. This project is required to ensure the safety and integrity of the trunk pipeline between Wilton and Horsley Park.[192]

321. JGN has established that there is a credible risk of stress corrosion cracking (**SCC**) developing in a pipeline such as the trunk pipeline between Wilton and Horsley Park and that the most effective and efficient means of managing that risk is by in-line inspection using a specialised tool. JGN provides a supporting report from Asset Engineering Solutions as appendix 4.4.

322. JGN does not accept the views of the AER's consultant that the conditions for SCC do not exist in the Wilton to Horsley Park trunk pipeline or that the proposed investigation could have been carried out in conjunction with the survey that JGN performed in November 2014.[193] The purpose of that survey was to detect metal loss and geometric defects in the pipeline. The tools used for those purposes are not capable of detecting SCC. Detection of cracking and especially axial cracking such as SCC, requires specialised crack detection tools.

323. This pipeline is critical to the continuity of gas supply to the whole of the Sydney and Newcastle markets. Even though there may only be a frequency classed as 'occasional' i.e. the event may occur occasionally in the life of the pipeline, the damage that can result from SCC together with the critical nature of the pipeline for supply and its location in the Sydney Basin leads to a consequence (severity) rating of 'major' (based on safety and supply) and thus a resultant risk ranking of 'high' if the condition of the pipeline is not monitored and investigated over time.[194] If this inspection is not undertaken JGN would need to increase planned maintenance and inspections including integrity digs, pipeline patrols and leakage detection to provide early identification of any failure. Other

191 Ibid, pp 6-35 and 6-46.

192 NGR, rule 79(2)(i) and (ii).

193 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Capacity Development and Facilities Renewal and Replacement, Report to Australian Energy Regulator*, September 2014, p 17.

194 Risk assessment in accordance with AS2885.1—2012.

capital and operating costs will also be incurred in the event that JGN has to respond to and repair a pipeline failure.

Facilities upgrade on the Northern Trunk

324. Sleeman Consulting cites three examples, from public sources, in support of a view that "political circumstances in NSW are presently unfavourable for the CSG industry".[195] Based on that view, Sleeman Consulting "consider[s] it unlikely that any CSG project development approvals will be granted in time to allow commitment to, then development of, a CSG project to commence delivery of material quantities of gas to Newcastle within the period to 2020."[196] JGN does not accept that position.

325. The Northern Trunk facilities upgrade is necessary to accommodate increased pressures that will occur during of the 2015-20 AA period.

326. AEMO's Gas Statement of Opportunities (**GSOO**) published in May 2014 forecast CSG entering the NSW network from the North starting in calendar year 2017. JGN has sought the views of AEMO and AGL Energy in response to the AER's draft decision. Both confirm their expectation that AGL Energy will begin delivering CSG from Gloucester during the 2015-20 AA period with first gas expected as early as late 2017 (AEMO) or mid-2018 (AGL Energy). AGL Energy also confirms that CSG from Gloucester is unlikely to be delayed beyond calendar year 2019.[197]

327. It is important for JGN to make timely investment in the facilities necessary to receive gas from new sources into the network. Diversifying sources of supply is in the long-term interests of consumers as it mitigates the risk of supply shortfalls and wholesale price pressures by best facilitating additional gas coming to market.

328. JGN must commence significant elements of the facilities upgrade works, including land purchases and design and procurement of long lead-time equipment well before CSG arrives. It is also prudent to schedule the works over a number of years to optimise delivery and minimise cost.

329. It is clear from the most recent advice from AEMO and AGL Energy that the most likely case is that CSG production will begin during the 2015-20 AA period. It follows that a prudent capex forecast should provide for the required facilities upgrade work to be completed during the period. JGN's revised proposal includes the Northern Trunk facilities upgrade projects.

330. If CSG is introduced before or during the delivery of this series of projects the result will be significantly higher opex costs for monitoring and maintaining these facilities.

4.6.2.2 TPC/FEED and related costs

331. JGN's proposal included three projects named "Planning Costs – Steel", "Planning Costs – Plastic" and "Planning Costs – Facilities" at a total forecast cost of $6.2 million, $2015 gross—referred to as TPC—for the 2015-20 AA period. TPC were allocated to the facilities renewal and refurbishment capex category.[198]

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195 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Capacity Development and Facilities Renewal and Replacement, Report to Australian Energy Regulator*, September 2014, p 17.

196 Ibid.

197 AEMO, undated letter, received 28 January 2015, refer appendix 4.5.

AGL Energy, letter dated 10 February 2015, refer appendix 4.6.

198 JGN, *2015-20 access arrangement information*, 30 June 2014, appendix 6.4, see for example Output|AAI Tables sheet, cell K43.

332. TPC include the costs of the following activities:

- front end engineering and design (**FEED**) costs, including both internal Jemena and external design engineers and drafting resources
- site investigation costs, including geotechnical costs, pot-holing, survey
- project establishment costs, development of detailed project plans, schedules, risk assessments, etc.
- long lead item specifications, produced by design engineers (internal and/or external)
- tender documentation preparation, for detailed design, fabrication, construction and commissioning (either as separable or combined tenders)
- tender processes, including issuing and reviewing tenders.

333. To try and avoid further misunderstandings, we now refer to those costs as "**FEED and related costs**".

334. These activities are essential elements of an effective capex governance process and contribute to ensuring that capex is spent prudently and efficiently. FEED and related costs are a distinct and necessary component of capital costs. As discussed in section 4.14.2, it is not valid for the AER to disallow those costs because they support the delivery of reference services to our customers.

335. JGN collects FEED and related costs together (as opposed to charging the costs directly to individual projects) in three separate cost collector projects—steel, facilities, and plastic. The steel and facilities components relate primarily to moderate and high complexity[199] facilities renewal and refurbishment projects while the plastic component relates primarily to rehabilitation projects in the mains and services renewal category. Accordingly, it is more appropriate that FEED and related costs be accounted for within those two capex categories than treated as an overhead and allocated across capex generally as proposed by the AER. Our revised proposal reflects that position. However, instead of presenting FEED and related costs as separate projects, the steel and facilities portions (two thirds of the forecast total) are allocated over projects in the facilities renewal and refurbishment category and the plastic component (the remaining one third) over the rehabilitation projects in the mains and services renewal category. See also section 4.14.2.

4.7 METER RENEWAL AND UPGRADE

4.7.1 AER'S DRAFT DECISION

336. The AER:

- accepts JGN's approach to replacing residential and I&C diaphragm meters as prudent and efficient[200]
- adopts the advice of Sleeman Consulting that:
  - JGN's proposed rate of defective I&C meter replacement is not justified and that the forecast should be based on the revealed historical trend which results in a lower replacement rate than proposed by JGN[201]
  - for Metretek projects:

199 The classification of projects is described in JGN, *2015-20 access arrangement information*, 30 June 2014, appendix 6.7, section 2.2.

200 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-39.

201 Ibid, p 6-39.

    - JGN's proposal to replace all Metretek devices is not justified and that allowance should be made for replacement of 60 modems per year instead[202]
    - replacement of the Metretek central data collection system should be delayed to 2021[203]
  - for MDLs:
    - replacement of 150 defective MDLs per year is prudent but that a second amount for replacement of 200 defective MDLs per year until 2014-15 should be disallowed as it is considered to be duplication[204]
    - JGN's proposal to replace all MDLs over the 2015-22 period is not justified.[205]
- excludes a project named "Upgrade of MDL modems due to NBN rollout" from its alternative capex estimate, but does not explain why.[206]

4.7.2 JGN'S REVISED PROPOSAL

337. Table 4–14 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for meter renewal and upgrade capex.

Table 4–14: Meter renewal and upgrade capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	37.85	39.88	41.93	39.45	36.24	195.35
AER's draft decision	28.15	30.82	31.51	30.09	26.99	147.57
JGN's revised proposal	36.94	39.29	41.66	39.87	36.34	194.11

338. JGN welcomes the AER's draft decision to approve JGN's proposed replacement of residential and I&C diaphragm meters. However, we do not accept the adjustments to allowances for replacement of defective I&C meters; replacement of Metretek devices and the central data collection system; and replacement of MDLs.

4.7.2.1 Replacement of defective I&C meters

339. JGN's revised proposal is based on an analysis of historical failure rates as set out in Table 4–15.

Table 4–15: Historical volume of defective I&C meter replacements – number per JGN financial year

JGN financial year (April to March)	2010	2011	2012	2013	2014
Volume	150	212	256	269	282

340. The actual failure rate for I&C meters has increased by an average of 17 per cent per year over the four years to FY14 but at a lower rate of 5 per cent per year for the two years to FY14. For purposes of the revised proposal we have forecast 1,788 defective I&C meter replacements over the 2015-20 AA period. This is based on an

[202] Ibid, p 6-40.

[203] Ibid, p 6-40.

[204] Ibid, p 6-40.

[205] Ibid, p 6-40.

[206] AER, *AER - draft decision JGN - capex - November 2014 - CONFIDENTIAL.xlsx*, Meter renewal & upgrade sheet, row 31.

assumed growth rate of approximately 5.5 per cent per year in the number of replacements. We consider that a forecast based on compound growth is preferable to the linear approach proposed by Sleeman Consulting given that the fleet of I&C meters is aging. Given the information available, we believe this is the best forecast in the circumstances.

Table 4–16: Volume of defective I&C meter replacements – number

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	301	300	325	400	400	1,726
AER's draft decision	305	315	325	335	345	1,625
JGN's revised proposal	321	338	356	376	396	1,788

4.7.2.2 Metretek projects

341. Metretek devices are installed on the meters of customers consuming more than 10TJ per annum. The devices and Metretek system record and collect required consumption data in a cost effective and timely manner in order to meet AEMO and billing requirements. In addition, customers can have access to the information recorded by the devices which they can use to help manage their energy consumption and other aspects of their businesses.

342. Part C of the Retail Market Procedures (NSW and ACT) published by AEMO requires, among other things, that JGN provide meter readings for daily-read meters to AEMO by 0930 and, in any event, no later than 1200 each day.[207]

343. Tariffs and commercial arrangements with large industrial and commercial customers require measurement and billing of daily quantities and maximum hourly volumes as provided in JGN's AA and RSA.

344. Without the data collection and communication capabilities of the Metretek system it would be necessary to undertake daily manual reads from over 500 sites between 0630 and 0930 each day.

345. If the Metretek system is unavailable and JGN fails to meet its obligations under the Retail Market Procedures, the operation of the Short Term Trading Market (**STTM**) Sydney hub will be adversely affected. Customer billing will also be adversely affected.

Replacement of Metretek devices

346. The AER accepts the advice of Sleeman Consulting that JGN's proposal to replace all Metretek devices is not justified and that allowance should be made for replacement of 60 modems per year instead.[208]

347. The Metretek devices are integrated data loggers and modems which send the consumption data through copper telephone lines to the Metretek central data collection server. The existing units require a dedicated line and initiate a dial up connection to transfer the data to the central server on a pre-planned schedule.

348. The new models proposed for use in the replacement programme utilise a 3G mobile connection to transmit the data to the central server and are capable of two way communication to enhance data management.

349. This replacement programme is in response to two factors:

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207 AEMO, *Retail Market Procedures (NSW and ACT),* version 14, clause 21.1.

208 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-40.

- the obsolescence of the current Metretek models
- the National Broadband Network (**NBN**) rollout.

350. The Metretek unit comprises a commercial pulse accumulator (**CPA**) and an electronic corrector interface (**ECI**). The supplier (Honeywell) has advised that JGN's existing equipment is no longer supported.[209] The manufacturer ceased production of the CPAs in 2007 and the ECI was completely discontinued at the end of 2014. The replacement for ECI and CPA is the Honeywell CNI-2, which is a data logger and serial data communications product with an integrated cellular radio transceiver (3G) i.e. a single integrated circuit board.

351. As both key components of the existing Metretek devices are no longer available, repairs of defective units are not possible and failure of any part of the device requires the replacement of the entire device with a current model. As a result JGN plans to proactively replace the older generation of units over the next five year period.

352. The current models of Metretek devices communicate via a dial-up connection over the two wire telephone system. When the NBN is rolled out to customer sites with Metretek devices, the Metretek device will not be able to communicate the data as the current versions used by JGN are not NBN-compatible as confirmed by the manufacturer.[210]

353. Specifically it is not possible to replace only the communications component (modem) as the equipment is obsolete and there is no suitable alternative product available.

354. Using the 3G wireless network in the new generation devices creates a significant increase in the power requirements. Hence for those installations where external 240V power is not available then the use of the newer CNI-2 devices will also require the installation of a solar power supply.[211]

Replacement of the Metretek central data collection system

355. The AER accepts the advice of Sleeman Consulting that replacement of the Metretek central data collection system should be delayed to 2021.[212]

356. The server backend of the Metretek system consists of:

- Metretek SMOD (smart modem) which provides the interface between the various Metretek field devices and the Metretek server
- Metretek server which is an integrated hardware/software device that records, processes, validates and stores the large amount of data received from the field. This device is then linked to the JGN billing and SCADA systems (for monitoring and management of alarms).

357. JGN is currently using version 3.11 of the Honeywell DC2009 Data Management Software that was first released in early 2008. An upgrade to version 3.20 is available and JGN plans to test and implement that upgrade.

358. Ausmeter advises that the DC2009 software will no longer be supported from early 2016 and that it is being replaced with a new product named "Power Spring".[213]

209 Ausmeter, letter dated 18 December 2014, refer appendix 4.7.

210 Ibid.

211 Ibid.

212 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-40.

213 Ausmeter, letter dated 18 December 2014, refer appendix 4.7.

359. There are significant risks associated with the continued use of unsupported software, however JGN believes that they are manageable in the short term. As such JGN proposes to continue with the DC2009 server software for several years, with the transition to the new Power Spring software planned for 2020.

360. Considering the importance of the Metretek system for compliance and billing and as a source of information for customers, and the maturity of the system in a normal technology lifecycle, JGN is firmly of the view that it would be imprudent to delay the upgrade beyond 2020.

4.7.2.3 MDL projects

361. MDLs are installed in multi-dwelling developments to capture consumption data from residential gas meters and hot water meters installed in individual apartments. Pulse data is received from the gas and hot water meters, recorded on the data logger, and sent to a central server via landline or mobile network.

362. The system overcomes the difficulty of attempting to perform timely meter reading where the meters are located in locked areas such as within individual dwellings or secure apartments. Without MDLs, JGN would have to access the premises to read the meters (with associated inconvenience for customers) or rely on estimated meter reads where access is not possible either because the customer is not present or denies access.

363. As at 1 July 2014 there were approximately 250,000 supply points (meters) connected to 9,928 MDLs. Each MDL can accept up to 32 input lines though in practice the number of connections per unit is between 5 and 32. The average number of connections per MDL installed over the four years of the current AA period to RY14 is 21.

Replacement of defective MDLs

364. The AER accepts that replacement of 150 MDLs per year is prudent based on advice from Sleeman Consulting which refers to OB C517-3.[214] That OB was completed in May 2013. JGN subsequently reassessed the forecast volume of defective MDL replacements and the forecast adopted in JGN's initial proposal is shown in Table 4–17:

Table 4–17: Volume of defective MDL replacements – number

	2015-16	2016-17	2017-18	2018-19	2019-20
JGN's initial proposal (1)	200	200	187	150	150
AER's draft decision	150	150	150	150	150
JGN's revised proposal (2)	200	200	187	150	150

(1) Source: Appendix 06.04 - JGN capex forecast model - CONFIDENTIAL.xlsb, Calc|Volume & Rates (RY) sheet, row 231.
(2) The reduction in replacements in the later years of the period is contingent on the "planned replacement of MDL equipment" project (OB C516-6) proceeding.

214 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Meter Renewal and Upgrade, Mains and Services Renewal and SCADA, Report to Australian Energy Regulator*, September 2014, paras. 2.8(iii) and 2.8(iv).

365. The higher level of defective MDL replacements forecast in JGN's initial and revised proposals is consistent with the observed numbers of replacements over the five years to 2014.

Table 4–18: Defective MDL replacements – calendar years 2010 to 2014[215]

Calendar year	2010	2011	2012	2013	2014
Total defective MDL replacements	234	216	138	219	406

366. The average for the four years to 2013 is 201.75.

367. JGN has maintained its initial proposal forecast for the revised proposal. The actual number of 406 defective replacements for 2014 suggests that, if anything, this forecast is conservative.

Defective MDL replacement costs are not double counted

368. The AER accepts Sleeman Consulting's conclusion that the replacement of 200 faulty MDLs per annum in advance of the complete replacement programme, as described in OB C516-6, doubles-up on the replacement of defective MDL's and should be excluded from the forecast.[216]

369. Relevantly, OB C516-6 summarises the MDL replacement project as:

- *Continue replacing 200 faulty units at a cost of $465,000 per year (declining as replacement program proceeds) – Total population of MDL units is approximately 9000*
- *Commence replacing 1500 MDLs per year with the alternative technology in FY16 at a cost of $4.5 M per year over 5 years*

370. $4.5 million per year over 5 years equates to a total cost of $22.5 million which is stated to be the total cost of the project on pages 1 and 4 of the Opportunity Brief (**OB**). That is, the stated total cost does not include any part of the cost of continuing to replace faulty units. There is no double-up.

Planned replacement of MDL equipment

371. The AER excludes the outright replacement of MDLs from its alternative capex estimate on the basis of Sleeman Consulting's advice that the outright replacement is not adequately justified.[217]

372. The MDL equipment was developed by Epitomy Pty Ltd for JGN in 1996 and the design has remained largely unchanged since then. The system design is now 17 years old and 800 units are currently over 15 years old. A significant number of devices will be over 20 years old by the end of the 2015-20 AA period. Figure 4–1 shows the age profile of installed MDLs.

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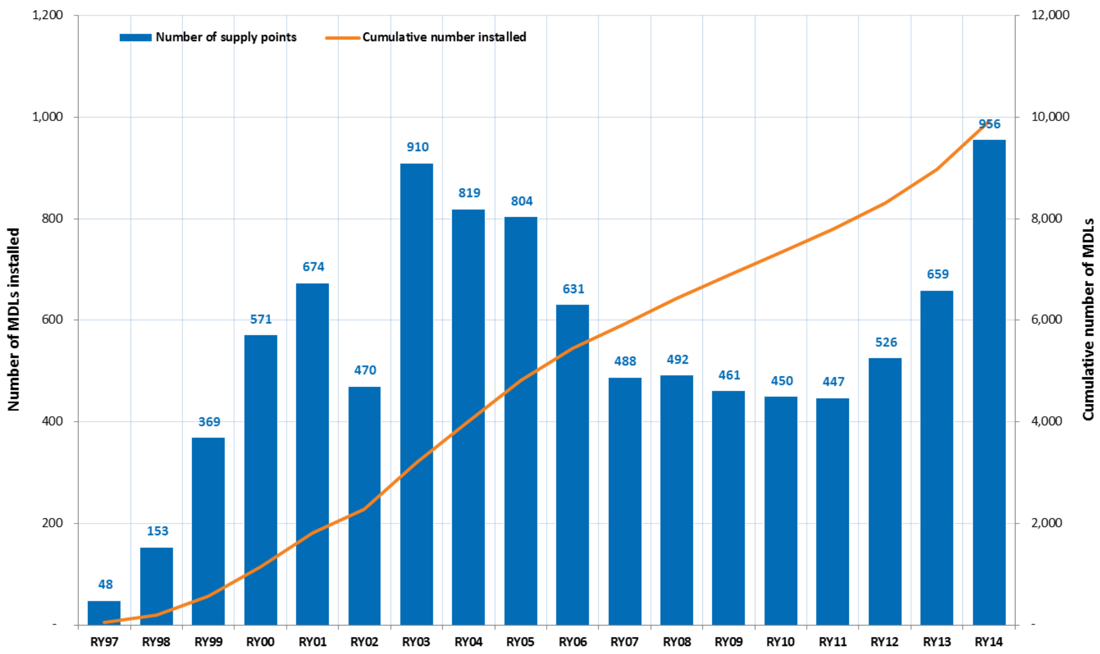
215 Data as provided in response to AER information request no 42 – appendix B1.4, with 2014 data added.

216 Sleeman Consulting, *Jemena Gas Networks 2015 Access Arrangement Submission, Review of Capex Forecasts for Meter Renewal and Upgrade, Mains and Services Renewal and SCADA, Report to Australian Energy Regulator*, September 2014, paras 2.8(iii) and 2.8(iv).

217 Ibid.

Figure 4–1: Age profile of MDLs



373. Importantly, Epitomy advises that "it would be prudent to implement a replacement strategy based on a 15 year life cycle", beginning with the older version 4 and 6.1 MDLs.[218] Planned replacement of the MDL units over 15 years old is also in accordance with prudent risk management.

374. OB C516-6 provides for 1,500 units to be replaced each year during the 2015-20 AA period for a total of 7,500 units over the period. The cost of the MDL replacement project does not include the cost of modems. JGN will reuse the modems that are installed in the "Upgrade of MDL modems due to NBN rollout" project (described below) when replacing the units.

375. The volumes and costs in the defective MDL replacement programme described above assume that the progressive replacement of aged MDLs will proceed. If the replacement programme does not proceed, the volume and unit cost of the defective replacement programme can be expected to increase significantly over the period. There is also a risk that parts and support will no longer be available. [219]

376. JGN's revised proposal therefore includes the Planned replacement of MDL equipment project.

Upgrade of MDL modems due to NBN rollout

377. The AER's alternative capex forecast does not include the project named "Upgrade of MDL modems due to NBN rollout" and described as "Upgrade of communications in MDL equipment resulting from the roll our (sic) of the NBN and withdrawal of the 2G mobile network to maintain levels of service for customers and manage efficient billing practices".[220] JGN also referred to this project in response to AER information request no 42.[221]

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218 Letter from Epitomy Pty Ltd, 9 December 2014 reproduced as appendix 4.8. Jemena currently has about 6,000 version 4 and 6.1 and about 3,000 version 6.6 MDLs installed.

219 Epitomy Pty Ltd is a sole trader and the only supplier of the MDL equipment.

220 JGN, *AAI appendix 06.04 - JGN capex forecast model - CONFIDENTIAL.xlsb*, Input|Project Costs sheet, row 838 and AER, *AER - draft decision JGN - capex - November 2014 - CONFIDENTIAL.xlsx*, Meter renewal & upgrade sheet, row 31.

221 JGN, *response to AER information request 42*, appendix B1.6.

Sleeman Consulting does not consider this project specifically and the AER does not give reasons for excluding the project.

378. The project is prudent and necessary to enable JGN to continue to bill customers.[222] With the implementation of the NBN and decommissioning of the 2G mobile network JGN must replace the modem incorporated within those MDLs that communicate externally so that they can access either the NBN directly or the 3G network. The MDL design allows for a new modem to be readily installed via a simple cable connection. This is in contrast to Metretek devices, where the Metretek and modem are integrated and must be replaced as a unit.

379. Only one MDL unit per apartment block is fitted with a modem for external communications—there are approximately 3,000 such units. Where there is more than one MDL in a complex, the other MDLs communicate with the central MDL via cable. Therefore, 3,000 MDL modems are to be replaced between April 2014 and March 2016 to manage the impact of the NBN. 1,125 of those will be replaced during the 2015-16 regulatory year.

380. JGN's revised proposal includes the Upgrade of MDL modems due to NBN rollout project.

Summary of MDL projects

381. Table 4–19 summarises MDL-related activities and movements in the numbers of MDLs over the 2014-15 to 2019-20 period.

Table 4–19: Summary of MDL projects – numbers of units

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Opening						
New technology		580	2,947	5,382	7,807	10,159
Old technology	9,928	9,992	8,289	6,589	4,902	3,252
Total	**9,928**	**10,572**	**11,236**	**11,971**	**12,709**	**13,411**
Activity						
NBN modem upgrade	1,500	1,125				
New connections	644	664	735	738	702	695
New technology	161	664	735	738	702	695
Old technology	483					
Defective replacement	176	200	200	187	150	150
New technology	44	200	200	187	150	150
Old technology	132					
Planned replacement	375	1,503	1,500	1,500	1,500	1,500
Closing						
New technology	580	2,947	5,382	7,807	10,159	12,504
Old technology	9,992	8,289	6,589	4,902	3,252	1,602
Total	**10,572**	**11,236**	**11,971**	**12,709**	**13,411**	**14,106**

222 NGR, rule 79(2)(c)(iii).

4.8 MINE SUBSIDENCE

4.8.1 AER'S DRAFT DECISION

382. The AER accepts JGN's forecast of mine subsidence capex but proposes a contribution rate based on the contributions data for the 2005-15 period in place of the rate proposed by JGN.[223]

4.8.2 JGN'S REVISED PROPOSAL

383. Table 4–20 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for mine subsidence capex.

Table 4–20: Mine subsidence capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	1.79	0.42	-	-	-	2.21
AER's draft decision	1.78	0.41	-	-	-	2.19
JGN's revised proposal	1.83	0.43	-	-	-	2.27

384. JGN's revised proposal for the direct, unescalated cost of mine subsidence capex is unchanged from its initial proposal and the AER's draft decision. However, JGN does not accept the contribution rate proposed by the AER—see section 4.13.

4.9 GOVERNMENT AUTHORITY WORK

4.9.1 AER'S DRAFT DECISION

385. The AER does not accept JGN's forecast of capex for government authority work (**GAW**). It proposes a lower forecast than JGN's (based on an average of 5 years instead of 3 years historical data)[224] and concludes that the forecast amount should be offset in full by capital contributions (citing practice in Victoria).[225]

4.9.2 JGN'S REVISED PROPOSAL

386. Table 4–21 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for GAW capex.

Table 4–21: Government authority work capex – $millions, $2015[226]

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	[c-i-c]					
AER's draft decision						

223 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-33.

224 Ibid p 6-41.

225 Ibid.

226 Note that, unlike corresponding tables in other sub-sections, the amounts in this table are net of contributions.

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's revised proposal	[c-i-c]					

387. JGN does not accept that its forecast of capex for GAW should be offset by additional assumed capital contributions. While not stated explicitly in our initial proposal, JGN's proposed forecast of capex for GAW is in fact net of contributions. Annual GAW expenditure on JGN assets over the current AA period has been in the range $4 million to $13 million. Our initial proposal reflects the fact that, on average, we recover all but about [c-i-c]. JGN always seeks to recover the cost from the party that requests/requires the work where it has the right to do so.

388. JGN has a variety of arrangements with land and infrastructure owners that relate to railway crossings and to the placement of JGN's assets on public and private land, and on road infrastructure such as bridges. Those arrangements do not necessarily provide for JGN to recover the cost of asset relocations required by the counter-party. For example, the agreement between JGN and the Commissioner for Main Roads under which JGN attached its infrastructure to the bridge across the Swansea channel at the entrance to Lake Macquarie, did not provide for JGN to recover the cost of altering/moving its infrastructure where required to do so by the Commissioner. JGN was required to alter its infrastructure when the fenders on the bridge were modified in RY14. In that case JGN chose to remove its infrastructure from the bridge and relocate it by drilling under the channel. [227]

389. Table 4–22 sets out the amounts of direct GAW expenditure, recoveries and net cost for the four years to 2013-14.

Table 4–22: Historical GAW expenditure, recoveries and net cost (1) – $million, $2015

	2010-11	2011-12	2012-13	2013-14	Average
Gross GAW	[c-i-c]				
Externally funded					
JGN funded					

(1) All amounts are direct before allocation of overheads.

390. The average net cost for the four years to 2013-14 is somewhat greater than the direct cost of [c-i-c] [c-i-c] ($2015) which was the basis for the forecast of GAW capex in JGN's initial proposal. JGN's revised proposal is unchanged from the initial proposal.

4.10 INFORMATION TECHNOLOGY

4.10.1 AER'S DRAFT DECISION

391. The AER accepts JGN's proposal in relation to Information Technology (**IT)** capex.

4.10.2 JGN'S REVISED PROPOSAL

392. Table 4–23 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for IT capex.

227 JGN described this project to the AER at a meeting on 14 March, 2014 – see appendix 1.7.

Table 4–23: IT capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	37.63	31.04	33.47	18.66	10.82	131.61
AER's draft decision	37.72	31.04	33.44	18.68	10.83	131.72
JGN's revised proposal	42.53	30.69	33.13	18.52	10.76	135.63

393. JGN's revised proposal for IT capex is unchanged from its initial proposal in terms of the scope and unescalated cost of those projects and activities that were included in the initial proposal and that the AER approved in its draft decision.

394. However, since submitting the initial proposal there has been a change of circumstances in that JGN now expects that it will be required to modify its business-to-business (**B2B**) and business-to-market (**B2M**) systems so that the processes that those systems support in NSW (and the ACT) are aligned with the corresponding processes in other jurisdictions. This is referred to as the **B2B harmonisation project**.

395. Accordingly, JGN's revised proposal for IT capex now includes a placeholder forecast of $5.2 million ($2015 unescalated) in RY16 for the added B2B harmonisation project. This cost has been estimated on the basis of JGN's current understanding of the market consultation process undertaken to date and we intend to confirm this estimate in March 2015, as advised in meetings with AER staff (refer appendix 1.7). The forecast reflects the costs of:

- *establishing IT infrastructure*—JGN will have to purchase additional hardware to cater for growth in processing and storage requirements, to ensure robustness, and to maintain the high service levels and system availability required by the market
- *developing and implementing necessary B2B and B2M capabilities*—JGN will be required to build systems to manage a number of completely new transactions and, in other cases, make changes to existing transactions to incorporate new data elements to comply with Participant Build Pack 5 of the Gas Interface Protocol
- *testing and change management*—material changes to complex systems must be managed rigorously through the development and testing phases before they can be migrated into production. Testing of the new/modified systems will include:
  - re-testing of the original solution to ensure that all processes, including those that have not changed, still perform correctly
  - end-to-end testing of processes which will involve AEMO and retailers.

  It will be necessary to create a full test environment including an appropriately configured and populated data set to support this testing.
- *industry testing and market certification*—a full certification process will be performed from November 2015 to March 2016 in accordance with the market schedule to ensure that the new and modified systems comply with applicable service levels and obligations. This will involve testing and validating the performance of:
  - customer accounts transfer and settlement
  - service orders (including new connections, disconnections and quoted services)
  - billing
  - new B2B and B2M transactions

  - standing data management
  - STTM
- *changes to major systems*—JGN will have to make changes to a number of corporate systems to conform to the new B2B and B2M specification and transaction requirements. Those systems include:
  - the SAP system which is currently being developed to replace JGN's existing GASS+ customer, asset and works management system
  - the webMethods system which provides the interfaces between the B2B and B2M systems and other applications and, in the present case, also provides the 'gateway' that handles messages between JGN's systems and the market hub
  - the web portal through which customers themselves will be able to initiate a range of transactions such as new connections
  - the ITRON MVRS system which manages meter reading processes and data.

396. Appendix 5.4 contains a more detailed discussion of the B2B harmonisation project.

4.11 SCADA

4.11.1 AER'S DRAFT DECISION

397. The AER accepts 17 of 19 SCADA projects and their proposed costs as prudent and efficient. Based on the advice of Sleeman Consulting, the AER does not accept JGN's proposal to replace the GENe SCADA system.[228]

4.11.2 JGN'S REVISED PROPOSAL

398. Table 4–24 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for SCADA capex.

Table 4–24: SCADA capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	1.32	2.72	2.78	2.19	0.75	9.76
AER's draft decision	0.63	0.54	0.66	0.69	0.72	3.24
JGN's revised proposal	1.31	2.69	2.75	2.16	0.74	9.64

399. The SCADA system is critical to the safety and integrity of network operation. The system also provides information for major customers and for the operation of the STTM.

400. JGN does not accept the AER's reasons for rejecting the GENe replacement expenditure and hence the AER's alternative forecast. We have included the forecast expenditure in our revised proposal.

401. [c-i-c]

[228] AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-36.

[c-i-c]

It is also the case that JGN's options for developing the systems and infrastructure that SCADA connects to and communicates with will be constrained if it stays with the current version of GENe. JGN's SCADA communicates with a number of important business systems including the geographical information system and the pi historian system which holds data used in the market-billing process and for network analysis. The JGN SCADA is also linked with Jemena Electricity Networks' SCADA in Melbourne as part of Jemena's business continuity strategy. Finally, SCADA is connected to IT servers and network communications infrastructure and communicates with field equipment such as remote terminal units, MDLs and Metretek.

403. Given the criticality of the SCADA system, and the maturity of the system in a normal technology lifecycle, it would be imprudent to delay replacing the system. Planned replacement is preferable to reactive replacement.

4.12 OTHER NON-DISTRIBUTION

4.12.1 AER'S DRAFT DECISION

404. The AER accepts JGN's proposal in relation to other non-distribution capex.[230]

4.12.2 JGN'S REVISED PROPOSAL

405. Table 4–25 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for other non-distribution capex.

Table 4–25: Other non-distribution capex – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	7.36	3.26	4.00	7.44	4.71	26.77
AER's draft decision	7.36	3.26	4.00	7.44	4.71	26.77
JGN's revised proposal	7.27	3.22	3.95	7.35	4.66	26.44

406. JGN's revised proposal for the direct, unescalated cost of other non-distribution capex is unchanged from its initial proposal and the AER's draft decision.

229 [c-i-c]

230 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, pp 6-43 and 6-44.

4.13 CUSTOMER CONTRIBUTIONS

4.13.1 AER'S DRAFT DECISION

407. In its alternative forecast the AER proposes that:

- the historically-observed eight year average contribution rate should be applied to all categories of market expansion capex [231]
- the cost of GAW should be offset in full by a capital contribution[232]
- the contribution rate for mine subsidence expenditure should be calculated by applying the 2005-15 contribution rate to forecast mine subsidence expenditure.[233]

4.13.2 JGN'S REVISED PROPOSAL

408. Table 4–26 compares JGN's initial proposal, the AER's draft decision and JGN's revised proposal for customer contributions.

Table 4–26: Customer contributions – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal	4.34	3.50	3.29	3.23	3.30	17.66
AER's draft decision	5.56	4.51	4.13	4.10	4.11	22.40
JGN's revised proposal	5.69	5.13	4.87	4.89	4.90	25.49

409. JGN's revised proposal:

- accepts that the historically-observed eight year average contribution rate should be applied to all categories of market expansion capex[234]
- does not accept that all GAW costs are recoverable as customer contributions (refer section 4.9)
- does not accept the AER's proposed higher rate of recovery for mine subsidence expenditure. A significant proportion of actual contributions received during the 2005-15 period came from the NSW Mine Subsidence Board following protracted litigation extending over approximately 10 years. Several months after the Mine Subsidence Board made payment to JGN in May 2014, the legislation was amended by the Mine Subsidence Compensation Amendment Act 2014 No 55 (NSW) to effectively preclude future recoveries for the relevant part of the JGN pipeline.

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231 Ibid, p 6-26.

232 Ibid, p 6-41.

233 Ibid, p 6-33.

234 JGN has also adopted the AER's approach to calculating the value of customer contributions for market expansion as implemented in the Connections sheet of the AER's draft decision model—AER - draft decision JGN - capex - November 2014 - CONFIDENTIAL.xlsx.XLSX. That is, the value of contributions for each market expansion segment is calculated as:

contribution rate **x** average contribution value **x** number of forecast new connections

where:

- *contribution rate* is the average historically observed percentage of new connections that attract a contribution
- *average contribution value* is the average historically observed value of each contribution.

In each case the average is calculated over eight years from 2005-06 to 2012-13.

410. [c-i-c]

4.14 ESCALATION, CAPITALISED OVERHEADS AND RELATED PARTY MARGIN

411. Note that the capex amounts detailed in preceding sections 4.3 to 4.8 and 4.10 to 4.12 inclusive are "Gross capex" that is, gross capex before customer contributions and including cost escalation and allocated overheads. The exception is section 4.9 where the amounts are net of contributions.

412. This section addresses the cost escalation, capitalised overheads and related party margin components of the capex forecast.

4.14.1 MATERIALS COST ESCALATION

413. The AER rejects JGN's proposal and adopts nil real escalation for the cost of materials.[235] JGN does not accept that providing zero real materials escalation provides us a reasonable opportunity to recover our efficient costs. Further information is set out in Table 5–1.

4.14.2 CAPITALISED OVERHEADS

4.14.2.1 AER's draft decision

414. The AER:

- accepts the 2013-14 base year amount of corporate and network overheads that JGN allocated to capex but does not accept JGN's proposed rate of change (applied at the component level) and instead applies its own opex rate of change at the aggregate level.[236]
- accepts that some allowance should be made for the costs categorised as direct overheads but does not accept JGN's proposed method of forecasting those costs—as a percentage of forecast direct capital costs. Instead, the AER considers that five years of historical data are required in order to assess the trend. In the absence of that data, the AER applies its opex rate of change to a base amount equal to the average of actual direct overheads expenditure for 2012-13 and 2013-14 as a "placeholder". The AER then discounts the amount calculated because it considers the historical unit rates that it has used to forecast market expansion capex already include an allocation of direct overheads.[237]
- considers that TPC i.e. FEED and related costs, should be treated as an overhead cost rather than as the aggregate of three projects within the facilities renewal and refurbishment category as proposed by JGN[238]

235 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-48.

236 Ibid, p 6-45.

237 Ibid, p. 6-45.

238 Ibid, p 6-35 and p. 6-46.

- analyses historical and forecast "total" planning costs—that is, the sum of network planning costs and FEED and related costs—and forms a view that the increase between 2012-13 and 2013-14 could not be justified.[239] The AER "[did not include] the step increase in forecast planning costs, which JGN proposed to include in the facilities renewal and upgrade category".[240]

4.14.2.2 JGN's revised proposal

415. Table 4–27 sets out JGN's revised proposal for capitalised overheads, compared with our initial proposal and the draft decision.

Table 4–27: Capitalised overheads – $millions, $2015

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
JGN's initial proposal						
Direct	10.23	10.51	10.79	10.26	9.43	51.21
Network	16.98	17.19	17.39	17.46	17.58	86.61
Corporate	1.28	1.30	1.31	1.32	1.33	6.54
Total	**28.50**	**29.00**	**29.49**	**29.04**	**28.34**	**144.36**
AER's draft decision						
Direct	3.85	3.82	3.91	3.71	3.40	18.69
Network	16.71	16.76	16.84	16.84	16.83	83.98
Corporate	1.26	1.27	1.27	1.27	1.27	6.34
Total per draft decision	**21.83**	**21.85**	**22.02**	**21.81**	**21.50**	**109.01**
Add amount of direct overheads that AER inferred was included in historical new connection rates	2.89	2.94	2.87	3.09	3.38	15.17
Implicit total	24.71	24.79	24.90	24.90	24.89	124.18
JGN's revised proposal						
Direct	7.10	7.18	7.28	7.34	7.41	36.31
Network	15.79	15.97	16.18	16.32	16.48	80.74
Corporate	1.91	1.93	1.96	1.98	1.99	9.77
Total	**24.80**	**25.08**	**25.42**	**25.64**	**25.88**	**126.83**

Direct overheads

416. JGN acknowledges that there are a number of ways in which allowance could be made for direct overheads. Noting our statement that "due to system limitations, JGN is only able to provide historical data for RY13 and RY14", the AER indicates a preference for assessing a trend over five years.[241]

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[239] Ibid, p 6-46 and Figure 6-3.

[240] Ibid, p 6-46.

[241] Ibid, p 6-45.

417. It is still the case that JGN cannot provide data for any period prior to RY13.[242] However, we now have data for the first six months of RY15, in which we have incurred $3.58 million.

Table 4–28: Direct overheads – $million, $2015

	2012-13	2013-14	2014-15 (extrapolated)
Direct overheads	6.20	7.29	7.16

418. 2012-13 was the first year in which costs were collected under the transitional arrangements which Jemena implemented from April 2012.[243] It is considered likely that there was some misallocation of costs early in that year as operational staff transitioned to the new cost collection approach. 2013-14 is likely to be a more representative year and reflect the best estimate of a sustainable base level of direct overheads. We note that the amount for the first six months of 2014-15, when annualised, is broadly in line with the actual amount for 2013-14 ($7.16 million versus $7.29 million), well above the amount for 2012-13.

419. In the revised proposal, JGN forecasts direct overheads using the base, step, trend method which the AER has accepted for other components of overheads, taking the actual amount for 2013-14 as the base year.

Network planning costs and FEED and related costs

420. We note that the AER accepts JGN's 2013-14 base year allocation of $18.3 million ($2015, escalated) for corporate and network overheads to capex.[244] That allocation does not include any amount of "direct overheads" or FEED and related costs. Nor does it include any allocation of "Network planning costs" or "Network control and operational switching (system planning)".[245] JGN accounts for both of these latter two categories of overhead as opex in its initial proposal.[246]

421. The network planning function covers:

- *asset strategy*—developing and managing the delivery of JGN's asset strategy, stay-in-business capex plans, asset management plans, and emergency strategy and contingency plans
- *asset class management*—developing and managing integrity plans and engineering assessments including requirement specifications
- *asset performance validation*—monitoring and validating the technical performance of assets, managing asset risks and formulating and initiating projects for corrective actions
- *programme planning processes*—developing business cases and requirement specifications for capex and opex, and analysing and reporting on capex and opex
- *maintaining asset records*—establishing and managing network maps, pipeline alignment sheets and engineering records

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242 JGN, Response to information request no 43a, 4 November 2014.

243 These arrangements are described in AAI appendix 4.1.

244 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, pp 6-45 and 6-46.

245 Network planning costs and Network control and operational switching (system planning) costs are reported in Table 14.1 of the AA RIN at rows 27 and 28 respectively.

246 This can be seen in JGN, *2015-20 access arrangement information*, 30 June 2014, appendix 07.1 - JGN opex forecast model - CONFIDENTIAL.xlsb. See rows 18 and 87, and 127 and 196 (for network planning costs) and rows 19 and 88, and 128 and 197 (for network control and operational switching (system planning)) in the sheet named "Calc|Opex Summary (view 2)".

- *easement management*—administrative functions including establishment of easements and managing land and survey enquiries.

422. The network control and operational switching (system planning) function covers:

- *maintaining meter data*—processing service requests from retailers for new connections, disconnection, reconnections and special reads, and customer transfers between retailers
- *SCADA service (control centre)*—management of SCADA communications systems including planned and corrective maintenance of the systems
- *monitoring and control (control centre)*—control room operations including monitoring operating conditions at network receipt points and in the trunk and primary systems, and at the inlet and terminal points in the secondary and medium/low pressure systems
- *SCADA planned and corrective maintenance*—performing planned and corrective maintenance on the SCADA master station, remote telemetry units and communication links.

423. All of the activities covered by the network planning and network control and operational switching (system planning) functions are distinct from those covered by FEED and related costs (refer section 4.6.2.2). Moreover, all network planning costs and network control and operational switching (system planning) costs are accounted for as opex.[247] That is, network planning costs and network control and operational switching (system planning) costs for 2013-14 are included in 2013-14 base year opex which the AER accepts.[248]

424. JGN forecasts overheads, including capitalised overheads, in the same way that it forecasts opex generally, that is, by using the accepted base, step and trend approach. Capitalised overheads in the base year (2013-14) comprise part of the costs in four overhead categories—management - O&M, project governance and related functions, information technology and human resources—and all of direct overheads. As noted above, direct overheads are now forecast using the same accepted base, step and trend approach that is used for other categories of overheads.[249]

425. It follows that the AER's analysis based on its Figure 6-3 is misinformed: it is not appropriate to include network planning costs (or network control and operational switching (system planning)) in an analysis of capitalised overheads. Moreover, the observed increase between 2012-13 and 2013-14 in Figure 6-3 is over-stated.[250] Even if the increase was correctly observed and it was appropriate to make some adjustment to address that increase, it is not valid to do so by simply disallowing FEED and related costs.[251]

426. As noted in section 4.6.2.2, FEED and related costs are a distinct and necessary component of capital costs and are more directly related to particular types of capex projects than to capex generally. In our revised proposal we have allocated the steel and facilities components of FEED and related costs over projects in the facilities renewal and refurbishment category and the plastic component over rehabilitation projects in the mains and services renewal category.

427. Further detail on our revised approach to forecasting capitalised overheads is set out in appendix 4.10.

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247 Refer footnote 246.

248 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 7-15.

249 This can be seen in AAI appendix 7.1 – *Appendix 07.1 - JGN opex forecast model - CONFIDENTIAL.xlsb*. See rows 75 to 102 in the sheet named Input|Opex (view 2).

250 Figure 6-3 appears to be a plot of network planning costs alone up to and including 2012-13 and the sum of network planning costs and FEED and related costs thereafter. Figure 6-3 therefore overstates the increase in costs between 2012-13 and 2013-14. We note that the amounts plotted do not include network control and operational switching (system planning).

251 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-46.

4.14.3 RELATED PARTY MARGIN

4.14.3.1 AER's draft decision

428. The AER's alternative estimate of market expansion capex does not include the margin paid to Zinfra on the grounds that "JGN did not set out why a Zinfra margin is incurred or how the margin is calculated".[252]

4.14.3.2 JGN's revised proposal

429. JGN does not accept that the Zinfra margin should be disallowed or that it failed to provide sufficient information for the AER to form a view that the margin is prudent and efficient.

430. JGN provided extensive information about its outsourcing arrangements, including with Zinfra, in its response to clause 9 of the AA RIN and clauses 9.4 and 9.5 in particular; and in AAI appendices 4.1, 4.2 and 6.8. JGN also provided copies of the FSA between Jemena Asset Management (**JAM**) and ZNX(2) and its annexures with the AA RIN.[253]

[c-i-c]

[252] AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-26.

[253] JGN also presented material on its outsourcing arrangements to the AER on 28 November 2012 and 27 November 2013 in the course of pre-submission engagement. That material was reproduced in JGN's initial proposal as Attachment A to 2015 AAI appendix 4.1.

[c-i-c]

[c-i-c]

436. Consistent with the fact that new connections work dominates the value of capital works performed by Zinfra, JGN includes the capitalised amounts of the management fee and management margin in the build-up of the fully-costed unit rates that it uses to forecast the cost of new connections. [257]

Summary

437. The AER has established a two stage approach for assessing related party contracts and margins in its Expenditure Forecast Assessment Guideline for Electricity Distribution. We understand that clause 9 of the AA RIN is intended to elicit all the information that the AER requires to enable it to apply that approach to JGN's outsourcing arrangements to the extent that they involve related parties.

438. JGN submits that, on any fair evaluation of all the material provided,[258] the FSA arrangements, including the management fee and management margin, are efficient:

- the largest component of charges under the FSA is based on market-tested unit rates which the AER accepts are efficient[259]
- the management fee compares favourably with JAM's cost of undertaking the same scope of work in-house for the Northern Region[260]
- the management margin [c-i-c] benchmarks favourably against margins earned by other comparable contracting businesses.

[c-i-c]

257 New connections work accounts for approximately 85 per cent of the value of capital works performed by Zinfra.

258 See response to clause 9 of the AA RIN and clauses 9.4 and 9.5 in particular; and in AAI appendices 4.1, 4.2 and 6.8.

259 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 6-47.

260 JGN, *2015-20 access arrangement information*, 30 June 2014, appendices 4.1 and 4.2.

439. We note that, in 2013, the AER assessed and allowed the related party margin paid by Murraylink on the basis of a similar benchmarking comparison of the related party margin against the EBIT margins earned by comparable businesses.[262]

261 JGN, *2015 AAI*, appendix 6.8 and clause 29 of FSA annexure A.

262 See AER, *Final decision, Murraylink Transmission determination, 2013–14 to 2017–18*, April 2013, p. 23.

5. OPERATING EXPENDITURE

Box 5–1 Key messages – operating expenditure

We welcome the AER's decision to accept the vast majority of our opex proposal as reflecting the lowest sustainable cost of delivering our required operating programmes over the next AA period. There are, however, some material areas of disagreement, in particular cost escalation and debt raising costs. In these areas, we present additional expert evidence to support our proposal.

We also put forward, for approval, three incremental opex step changes to reflect changes in circumstances since our initial opex proposal was prepared.

Where new information has become available we have updated cost estimates to ensure they remain the best estimates in the circumstances—and compliant with the NGR rule 74(2).

5.1 AER DRAFT DECISION

440. The draft decision accepted most elements of JGN's opex forecast, including our opex forecasting method, the nomination of 2013-14 as an efficient base year for opex forecasting and five of six proposed opex step changes. The areas of difference between the draft decision forecast and our initial forecast were:

- *rate of change*—the AER considered our forecasts of input price changes were not the best estimates possible in the circumstances
- *regulatory reporting step change*—the AER did not include any forecast increase in opex related to annual regulatory reporting because the AER does not intend to materially increase reporting obligations in the 2015–20 AA period
- *debt raising costs*—the AER considered that our forecast of debt raising costs is not the best estimate possible in the circumstances.

5.2 JGN RESPONSE TO THE DRAFT DECISION

5.2.1 RATE OF CHANGE

441. Our response to the different components of the draft decision's proposed rate of change is summarised in Table 5–1.

Table 5–1: JGN response to draft decision on rate of change

Element	Position	Further explanation
Escalation weights	**Do not accept** (1) Maintain our initial position, using our *firm* specific escalation weights.	• JGN disagrees that the opex escalation weights—used in determining real cost escalator forecasts—should reflect an *industry* specific benchmark (62/38 as labour/non labour split). • This benchmark split—sourced from Pacific Economic Group— was used by Economic Insights (**EI**) to derive JGN's opex partial factor productivity estimates. • JGN maintains its position to apply its *firm* specific escalation

Element	Position	Further explanation
		weights—consistent with its initial proposal. This is because opex escalation weights should reflect our *firm* specific opex split, which is represents the base year split that is used to roll-forward opex allowances.
Real cost escalators	**Do not accept** (1) We disagree with AER position that an average of BIS Shrapnel and DAE is the best estimate in the circumstances (2) We disagree with AER position that no real material cost escalators should be included (3) We maintain our position (using BIS Shrapnel's forecasts) and updated our dataset for latest available information.	• JGN maintains its initial position, in relying on BIS Shrapnel's expert advice on forecast price of materials and labour. • We consider BIS Shrapnel to be a respected expert economic forecasters and believe their updated forecasts are best estimates in the circumstances in accordance with NGR rule 74(2)—refer to appendix 5.1 for their updated expert report. • For material cost escalators, BIS believes that quantifying the relationship between final prices and the underlying inputs is not practical. Putting together a long enough time series of prices of physical assets to make it amenable to econometric modelling — in order to numerically estimate the relationship — is almost impossible. • BIS further notes that this methodology (i.e. one based on weighted average of input costs) has previously been accepted by the AER[263]. • Accordingly, we believe that the AER should be consistent in its approach and approve our input cost methodology for deriving material cost escalation forecasts rather than simply apply a zero real escalation. • Furthermore, we also believe that our opex forecast is conservative, in that BIS' updated real cost escalators did not take into account the recent depreciation in the Australian dollar. If we updated the USD to AUD exchange rate, this will increase our opex forecast.
Network growth	**Partially accept** (1) We have substituted DAE's demand forecasts with an updated forecast by Core Energy. (2) We have retained the methodology used to estimate network growth component within the opex rate of change (3) We have updated our dataset for the latest available information.	• JGN disagrees with the DAE's demand forecasts, and substituted these with updated Core Energy forecasts. • The forecasts and weights are sourced from updated Core Energy demand forecasts (refer chapter 3) and updated EI analysis (refer appendix 5.2). • JGN has updated its dataset to reflect (a) RY14 actual opex, (b) updated RY15-20 forecasts for both customer numbers and volume throughput as well as (c) updated weights for the two output variables.
Opex partial factor productivity	**Accept** (1) We retain the econometric modelling from EI. (2) We update our dataset for latest available information. (3) We apply EI's *industry* specific escalation weights (as JGN is not in a position to develop an alternative	• JGN's revised forecast retains the econometric modelling unchanged, but updates its forecasts to reflect (a) RY14 actual and (b) RY15 to RY20 forecasts (refer appendix 5.2). • Similarly to determining real cost escalator forecasts, JGN disagrees that the opex escalation weights used to forecast opex PFP should reflect an *industry* specific benchmark. • However, EI argues that in order to be able to substitute its *industry* specific benchmark split with JGN's specific weights,

263 AER, Draft Decision, *SP AusNet Transmission Determination 2014/15 to 2016/17*, August 2013, p.67

Element	Position	Further explanation
	estimate).	they require historical opex to be split over the period 1999 to 2014—which is unrealistic. • Whilst JGN favours the use of our *firm* specific weights we are unable to provide the required dataset, which means we are not in a position to develop an alternative estimate.

5.2.2 REGULATORY REPORTING STEP CHANGE

442. The AER has rejected our proposed step change in opex to account for an anticipated material increase in regulatory reporting obligations.

443. We proposed this step change because we anticipated that the AER would escalate its annual regulatory reporting requirements from the first year of the next AA period. This would be consistent with significantly increased reporting requirements for electricity networks and JGN's AA RIN.

444. We note that the AER has committed to not materially increase its annual regulatory reporting requirements for JGN.[264] We therefore withdraw our step change proposal in this revised proposal.

5.2.3 DEBT RAISING COSTS

445. We do not accept the AER's draft decision on debt raising costs. We engaged Incenta to review the AER's draft decision and Incenta has material concerns with the AER's analysis. We agree with these concerns. Incenta's expert report can be found at appendix 5.3.

5.3 JGN RESPONSE TO CHANGED CIRCUMSTANCES

446. Since we prepared our initial proposal, there have been several important changes in circumstances that require us to update our opex forecast. These ensure that our proposed opex forecast—and the AER's final opex decision—is able to comply with rule 91 of the NGR as being the lowest sustainable level of opex to deliver reference services over the 2015-20 AA period.

5.3.1 BASE YEAR ACTUAL COSTS

447. The draft decision accepted 2013-14 as an efficient base year from which to forecast opex for the 2015-20 AA period. As noted in our initial proposal, JGN's actual cost data for the full 2013-14 year was not yet available at 30 June 2014. We relied upon recent estimates which comprised a mixture of actual and forecast opex for 2013-14. We noted that this estimate will be updated in response to the AER draft decision using actual data.

448. This revised proposal updates the 2013-14 estimated base year level of expenditure.[265] Our forecast also reflects an updated view of one-off opex and adjustments incurred in 2013-14.

5.3.2 RATE OF CHANGE UPDATE

449. Our rate of change forecast update has been prepared as summarised in Table 5–1.

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264 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 7-23.

265 JGN, *2013-14 annual RIN submission to the AER*, November 2014 (refer supporting information).

5.3.3 ADDITIONAL PRUDENT OPERATING PROGRAMMES

450. Our initial opex forecasts were prepared in early 2014. A year later, and with the publication of the draft decision, we have identified important additional incremental activities necessary to comply with new regulatory obligations, meet good industry practice and protect our customers' and employees' health and safety. Detailed explanations of our proposed step changes are set out in appendix 5.4.

451. In summary, JGN proposes additional opex to reflect:

- a new regulatory obligation for JGN to obtain an independently audited or verified statement to support gas quantity inputs used in the reference tariff variation formula (refer section 11.2.4)
- a new employee and public safety initiative to remove customer-owned asbestos meter covers
- new regulatory obligations regarding B2B service levels and market requirements.

452. The forecast incremental costs for these proposed step changes are set out in Table 5–2.

Table 5–2: Opex step changes summary ($2015, $millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Gas quantity audit	0.03	0.03	0.03	0.03	-	**0.14**
Asbestos meter covers removal	0.18	0.80	-	-	-	**0.97**
B2B harmonisation	1.50	3.00	2.50	2.00	2.00	**11.00**

5.3.4 UAG FORECAST

453. Our initial proposal UAG forecast assumed a conservative forecast of wholesale gas prices. We have reviewed this forecast in light of the most recent competitive tender price achieved for UAG. Our initial and revised UAG price forecasts are set out in Table 5–3.

Table 5–3: Wholesale gas price assumptions, initial and revised AA proposals, $dollar/GJ ($2014)

	2015-16	2016-17	2017-18	2018-19	2019-20
Initial proposal			[c-i-c]		
Revised proposal					

454. In light of this material difference, we have updated our UAG forecast to reflect more recent information.

455. We note that an automatic adjustment applies in the tariff variation mechanism to true-up actual and forecast gas prices assumed in UAG costs (recognising the gas price as a cost that is beyond our control)—refer chapter 11.

5.3.5 CARBON COSTS FORECAST

456. The forecast of carbon costs included in JGN's initial opex forecast comprised:

- carbon costs on our assumed fugitive emissions (distribution and transmission)—over 98 per cent of forecast carbon costs
- annual audit costs to support our National Greenhouse and Energy Reporting (**NGER**) scheme reporting requirements—amounting to less than 2 per cent of forecast carbon costs.

457. As a result of the repeal of the Clean Energy Act, carbon costs on our fugitive emission are no longer required and have been removed from the opex forecast.

458. As previously advised[266], we consider that the audit costs are still required. Even after the repeal, JGN must still report its assumed fugitive emissions each year under section 19 of the NGER Act 2007—and there are strict penalties if JGN does not comply with this or provides false information. To meet this obligation fully, JGN considers it prudent to audit its reporting each year—and has done so for both 2013 and 2014 and intends to continue doing so. Although not legally required, we consider such an audit is needed to provide sufficient assurance to those approving the report (and the underlying data).

459. Section 19 of the NGER Act 2007—which remains in force even though sections 22A and 22AA (relating to carbon costs) were repealed—is set out below.

> ***19 Report to be given to the Regulator***
>
> *(1) A corporation registered under Division 3 of Part 2 must, in accordance with this section and in respect of each financial year mentioned in subsection (2), provide a report to the Regulator relating to the:*
>
> *(a) greenhouse gas emissions; and*
>
> *(b) energy production; and*
>
> *(c) energy consumption;*
>
> *from the operation of facilities under the operational control of the corporation and entities that are members of the corporation's group, during that financial year.*
>
> *Civil penalty: 2,000 penalty units.*
>
> *Note 1: Under Division 137 of the Criminal Code it may be an offence to provide false or misleading information or documents to the Regulator in purported compliance with this Act.*

5.4 OUR REVISED PROPOSAL

460. Table 5–4 summarises JGN's revised opex forecast for the next AA period. Our revised opex model is provided as appendix 5.5.

461. Our revised opex proposal is generally consistent with our initial proposal. It reflects new circumstances and market data to ensure it remains the best estimate possible in the circumstances. Our opex proposal reflects the minimum funding necessary to deliver the operating programmes that support the services our customers' value.

462. As explained in our initial proposal, JGN also notes that we are a strong performer in terms of opex efficiency and we have had similar total factor productivity levels as two of the three Victorian gas distribution businesses over the last decade. We are among the most efficient gas distribution businesses in terms of opex cost efficiency when the effects of scale, customer density, network age and network fragmentation are taken into account. JGN's opex efficiency is not statistically different from the efficient frontier level.

266 JGN, *Response to information request #31*, 11 September 2014.

Table 5–4: JGN revised forecast opex over next AA period ($2015, $millions)

Level 1 category		Actual	Estimate	Next AA period					
	Level 2 category	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
O&M	Maintenance	28.37	27.43	27.77	28.56	28.01	28.16	28.30	**140.80**
	Emergency response	4.50	4.39	4.41	4.44	4.48	4.50	4.53	**22.37**
	Management - O&M	12.66	12.35	12.43	12.50	12.62	12.68	12.75	**62.98**
	Network planning	6.52	6.37	6.40	6.44	6.50	6.53	6.57	**32.45**
	Network control and operational switching	7.05	6.88	6.92	6.96	7.02	7.06	7.10	**35.06**
	Project governance and related functions	5.08	4.96	4.99	5.02	5.06	5.09	5.12	**25.28**
	Quality and standard functions	3.51	3.43	3.45	3.47	3.50	3.52	3.54	**17.48**
	Other	13.56	13.80	15.43	14.48	14.82	14.71	14.84	**74.28**
	IT	14.32	13.97	15.55	17.14	16.77	16.34	16.41	**82.21**
	Corporate overheads - O&M	17.31	16.89	16.99	17.09	17.25	17.34	17.43	**86.10**
	Pigging/Integrity digs, adhoc mains renewal	1.49	4.29	-	-	-	-	-	**-**
Non-O&M (A&O)	Corporate overheads - A&O	9.36	9.22	9.34	9.39	9.48	9.53	9.54	**47.27**
	Management - A&O	2.41	2.35	2.37	2.38	2.40	2.41	2.43	**11.99**
	Other directs	5.53	3.02	3.03	3.05	3.12	7.56	6.40	**23.17**
Non-O&M (Other)	Government levies	3.98	3.98	3.98	3.98	3.98	3.98	3.98	**19.88**
	Marketing	7.65	7.46	8.81	8.85	8.92	8.96	9.00	**44.54**
	Unaccounted for gas (UAG)	13.74	16.36	15.85	15.86	15.79	15.71	15.68	**78.89**
	Carbon costs	7.17	0.04	0.04	0.04	0.04	0.04	0.04	**0.21**
	Debt raising costs	-	-	3.23	3.32	3.40	3.47	3.50	**16.92**
Total	**Total JGN opex**	**164.20**	**157.18**	**160.96**	**162.99**	**163.18**	**167.60**	**167.14**	**821.87**

6. CAPITAL BASE

Box 6–1 Key messages – capital base

We generally accept the AER's approach to determining the value of our capital base. We do not accept that the NGR and NGL do not allow us to recover the funding costs associated with our actual capex in 2009-10.

6.1 AER DRAFT DECISION

6.1.1 ROLL FORWARD OF CAPITAL BASE DURING THE 2010-15 AA PERIOD

463. Except for the adjustment for the difference between estimated and actual capex in 2009-10, the AER accepts the principles that JGN has proposed and adopted for rolling forward the capital base over the 2010-15 AA period and JGN's proposed opening value of the capital base for 2015-16.[267]

6.1.2 PROJECTED CAPITAL BASE FOR THE 2015-20 AA PERIOD

464. Setting aside the changes to inputs to the calculation[268], the AER accepts the principles that JGN has proposed and adopted for projecting the capital base forward over the 2010-15 AA period with the following exceptions:

- the AER accounts for pigging and integrity dig expenditure in the trunk asset classes instead of in the contract meter class as proposed by JGN[269]
- the AER proposes that the standard life for vehicles be six years instead of four.[270]

6.2 JGN RESPONSE TO THE DRAFT DECISION

6.2.1 UPDATED VALUES

465. The projections of the capital base in JGN's revised proposal are based on actual data for capex, capital contributions and asset disposals for the years 2010-11, 2011-12, 2012-13 and 2013-14 and, for subsequent years, changes that are consistent with other aspects of the revised proposal including:

- updated values of the consumer price index (**CPI**) for 2013-14 and 2014-15
- updated market expansion volumes and unit rates
- changes to the capex programme and to the method of forecasting direct overheads as described in chapter 4

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267 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, section 2.4.1.

268 Inputs are the 1 July 2015 opening capital base, the amount of forecast net capex and related amount of forecast depreciation for each year of the 2015-20 AA period, and forecast CPI.

269 Apparent from rows 89 to 91 of the Input|Costs sheet in *AER - DD JGN - total revenue - AER draft decision - Revenue model CONFIDENTIAL.XLSB*

270 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, section 8.5.2.

- updated materials cost escalators.

6.2.2 ADJUSTMENT FOR THE CAPEX DIFFERENCE IN 2009-10

6.2.2.1 AER draft decision

466. The AER does not accept JGN's proposal to include in the 2015-16 opening capital base an adjustment for the accumulated return on capital associated with the difference between estimated and actual capex for 2009-10.[271]

6.2.2.2 JGN response to the draft decision

467. JGN considers that the adjustment to the opening capital base for the difference between actual and estimated capex in 2009-10 should include the accumulated return on this difference for two reasons:

- first, this adjustment ought to be made regardless of whether the current or previous version of rule 77(2)(a) applies
- secondly, JGN considers that the current version of rule 77(2)(a) should apply to the AER's decision, and therefore there should be no doubt that the adjustment is required.

468. Each of these points is addressed below. Gilbert+Tobin have also provided advice on this aspect of JGN's revised proposal—see appendix 6.1.

Adjustment ought to be made regardless of whether the current or previous version of rule 77(2)(a) applies

469. When JGN submitted its initial proposal in June 2014, the previous version of rule 77(2)(a) was in force. This previous version did not explicitly state that the adjustment to account for the difference between actual and estimated capex included in the opening capital base for the prior period was to remove any benefit or penalty associated with that difference. However, JGN's initial proposal was prepared on the understanding that the adjustment ought to be made even under the previous version, consistent with previous AER practice.[272]

470. JGN notes that the AER's long-standing practice under the previous version of rule 77(2)(a), was to make this adjustment. The AER considered that this was necessary to properly adjust the capital base for the difference between estimated and actual capex, as required by rule 77(2)(a). The AER also considered that such an adjustment would promote the NGO, as it would encourage efficient investment by removing any incentive to overestimate capital expenditure or defer efficient expenditure during the final year when an access arrangement review is occurring.[273]

471. JGN understood that the rationale for the AER's proposed change to rule 77(2)(a) was to clarify the operation of this provision. It was understood that this change would merely clarify and codify an existing practice, rather than substantively changing the operation of rule 77(2)(a).

472. It was for this reason that JGN proposed to make the relevant adjustment in its initial proposal. JGN considered that even under the previous version of rule 77(2)(a), the adjustment ought to be made.

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[271] AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p. 2-15.

[272] For example, this adjustment was made in the AER's final decision on JGN's access arrangement revisions proposal for the 2010-2015 period (AER, *Final Decision: Jemena Gas Networks Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015*, June 2010, p 42).

[273] For example: AER, *Access arrangement final decision: APA GasNet Australia (Operations) Pty Ltd 2013–17 – Part 2: Attachments*, March 2013, pp 27-28.

473. JGN maintains its view that the adjustment should be made under either the previous version of rule 77(2)(a) or the current version. Therefore, whether the previous or current version of this rule applies should not make any practical difference.

The AER is not prevented from applying the current version of rule 77(2)(a)

474. Even if the AER's (revised) interpretation of the previous version of rule 77(2)(a) were to be accepted, this should not preclude an adjustment to the opening capital base for the return on this difference between actual and estimated capex in 2009-10. JGN considers that the current version of rule 77(2)(a) should apply to the AER's decision on JGN's AA revision proposal, not the previous version.

475. The AER appears to consider that it cannot apply rule 77(2)(a) in its current form (i.e. as amended by the AEMC in October 2014), on three grounds:

- that the AER's assessment of JGN's AA is governed by the legislation current at the date that JGN submitted its initial proposal (i.e. 30 June 2014)
- in amending rule 77(2)(a), the AEMC intended that the rule as amended "would not apply to JGN"
- as a matter of procedural fairness it would not be appropriate to assess the AA under a different framework than that under which JGN made its proposal and stakeholders made submissions on that proposal.[274]

476. We address these grounds in turn.

The first ground

477. The first ground appears to be based on clause 43 of schedule 2 of the NGL which states that:

> ***43—Saving of operation of repealed Law, Regulation or Rule provisions***
>
> *(1) The repeal, amendment or expiry of a provision of this Law, the Regulations or the Rules does not—*
>
> *(a) revive anything not in force or existing at the time the repeal, amendment or expiry takes effect; or*
>
> *(b) affect the previous operation of the provision or anything suffered, done or begun under the provision; or*
>
> *(c) affect a right, privilege or liability acquired, accrued or incurred under the provision; or*
>
> *(d) affect a penalty incurred in relation to an offence arising under the provision; or*
>
> *(e) affect an investigation, proceeding or remedy in relation to such a right, privilege, liability or penalty.*
>
> *(2) Any such penalty may be imposed and enforced, and any such investigation, proceeding or remedy may be begun, continued or enforced, as if the provision had not been repealed or amended or had not expired.*

478. JGN considers that this provision does not prevent the AER from applying the current version of rule 77(2)(a) in its decision on JGN's AA revision proposal.

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[274] AER, JGN 2015-20 access arrangement draft decision, 27 November 2014, p. 2-16.

479. The main purpose of this provision is to preserve existing rights or liabilities accrued prior to amendment of a provision and to prevent things done previously being revisited when rules have changed. For example, a decision of the AER made under the previous version of the NGR cannot be re-opened simply because those rules have subsequently changed.

480. The only part of this provision which may be relevant to the present case is sub-clause (1)(b) which prevents amendment to a provision of the NGR affecting the previous operation of that provision, or anything "suffered, done or begun" under that provision as it applied before the amendment. The AER's position appears to be that the provision was triggered on 30 June 2014 when JGN submitted its initial proposal and so any amendment to the NGR relating to the AA or price regulation after that date cannot affect the review process.

481. We do not accept that interpretation of clause 43.

482. It is important to note that sub-clause (1)(b) applies to anything begun *under the provision*. Therefore, the relevant question is: when did anything begin under rule 77, which would be affected by the amendment of that provision?

483. Clause 43 does not say that any amendment to the NGR which takes effect after a review process has commenced cannot apply in that process, or that the unamended (old) version of the NGR must apply. Rather, it says that amendment of a provision cannot affect anything "done" or "begun [to be done]" under a previous version of that provision—for example, any decisions made under a previous version of that provision are not affected.

484. In the case of the process involving JGN's AA proposal, nothing had begun under rule 77 as at the date of the amendment which would be affected by the amendment. It is true that an AA review process had begun, but that occurred under other provisions in Part 8 of the NGR, which have not been amended by the AEMC. Therefore, nothing had been "done, suffered or begun" under rule 77 as at the date of JGN's submission (30 June 2014) which would be affected by the amendment.

485. JGN submits that the first formal application of rule 77 in the current review process occurred when the AER made its draft decision in late November, that is, after rule 77 was amended.

486. JGN does not accept that clause 43 of schedule 2 of the NGL applies in this particular context, and accordingly the AER is not prevented from applying the amended rule 77 in making its draft and final decisions in relation to JGN's AA proposal for the 2015-20 AA period. Accordingly, the AER should apply rule 77(2)(a) as it currently stands in making its final decision on JGN's AA revision proposal.

The second ground

487. The AEMC published its consultation paper on the AER's rule change proposal on 17 April 2014. In our submission of 22 May 2014 on the consultation paper, we proposed that, if rule 77 was to be amended, then it should apply from 17 April 2014 thereby putting any question of its application beyond doubt.

488. We agree that the AEMC did not act on JGN's submission. The amendment itself is not back-dated to when the rule change proposal was published (April 2014), as had been proposed by JGN. Rather, the AEMC decided that the rule change should take effect from when it published its decision (October 2014).

489. However, it is clear that the amended rule was to take effect from October 2014, and there is no related transitional provision that limits its application from that date. Given the absence of any transitional provision limiting the effect of the amended provision in this case, the AER should apply rule 77(2)(a) as it currently stands in making its final decision on JGN's AA revision proposal.

The third ground

490. The AER suggests that procedural fairness requires that a review must be conducted as if the NGL was frozen as at the time the service provider submits its initial proposal.

491. An applicable change in law during a process in fact provides the clearest reason and basis for a change in approach. For example it is reasonable to expect that a change in applicable tax law at any time during a review process would have to be taken into account otherwise forecasts would not be the best in circumstances.

492. The AER has frequently introduced elements into its final decisions that have not been canvassed in its draft decisions and have not arisen out of consultations. The AER's decision in 2010 to adjust JGN's 2010-11 opening RAB for the accumulated cost of capital on the difference between actual and estimated capex for 2004-05 is a case in point.[275] In that case the decision was based on an unheralded interpretation of rule 77 and, since it was in a final decision, it was not open to consultation.

493. In the case of rule 77 the AER's position and conduct has been consistent and transparent since 2010 and especially since the Tribunal's decision on GasNet in September 2013 which reversed the Tribunal's earlier JGN decision and was the catalyst for the AER's rule change proposal. It should be no surprise to any interested party that, in the absence of a specific prohibition, the AER would wish and choose to apply the amended rule 77.

6.2.3 CLASSIFICATION OF PIGGING AND INTEGRITY DIG EXPENDITURE

494. In our initial proposal we proposed to capitalise pigging and integrity dig expenditure which is consistent with recent AER decisions. In so doing we noted that "JGN performs in-line inspections typically every ten years, and integrity digs on a periodic basis. The value of these investigations is effectively applied over the period between successive rounds of activity."[276]

495. Rather than establish a new asset class with a 10 year life for pigging and integrity digs, JGN elected (conservatively) to include the expenditure in the contract meters asset class which already exists and has a 20 year life. The AER apparently accepts JGN's proposal to capitalise the expenditure but then includes the expenditure in the trunk asset classes which have a life of 80 years.[277] The AER does not give reasons for the re-classification.

496. JGN does not accept the re-classification. A life of 20 years is more consistent with the depreciation criterion that "each asset or group of assets [should be] depreciated over the economic life of that asset or groups of assets"[278] than is a life of 80 years. Accordingly, pigging and integrity dig expenditure is included in the contract meters asset class in the revised proposal.

6.2.4 STANDARD ASSET LIVES

497. The AER accepts the standard asset lives proposed by JGN for all asset classes except motor vehicles where the AER requires a standard life of six years instead of four years as proposed by JGN.[279]

498. JGN accepts the AER's draft decision.

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275 For example, this adjustment was made in the AER's final decision on JGN's access arrangement revisions proposal for the 2010-2015 period (AER, *Final Decision: Jemena Gas Networks Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015*, June 2010, p 42).

276 JGN, *2015-20 access arrangement information*, 30 June 2014, section 6.3.4.1.

277 Apparent from rows 89 to 91 of the Input|Costs sheet in *AER - DD JGN - total revenue - AER draft decision - Revenue model CONFIDENTIAL.XLSB*.

278 NGR, rule 89(1)(b).

279 AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, section 8.5.2.

7. RATE OF RETURN

Box 7–1 Key messages – rate of return

Our owners invest in network businesses for the long-term, and seek sustainable returns as part of their asset portfolios. Our owners want gas to remain an attractive energy source in NSW and therefore, like our customers, expect the JGN business to be managed at lowest sustainable cost over the long-term. This equally extends to their required regulatory rate of return.

Our proposed rate of return reflects a commercial rate of return required to invest in a benchmark efficient entity facing similar risks to JGN. It directly considers all available relevant evidence on the cost of equity funding instead of attempting to pick a winner among financial models. Our proposed return on debt method and transition reflects the costs that the benchmark efficient entity would incur over the next AA period.

We engaged Australia's leading finance experts to provide an opinion on key elements of our proposal, and our proposal reflects these expert opinions. We consider the AER's rate of return guideline, but—just like the AER's draft decision—recognise that it is not binding.

Importantly, in response to the draft decision and changed market circumstances, we reviewed the additional costs and risks that the benchmark efficient entity would bear from adopting various return on debt transitions. In light of this assessment, we have adopted a different transition—a hybrid approach—in our revised proposal.

There are material and negative customer consequences of not providing investors and debtors with a benchmark return that reflect market conditions. If underfunded, we would have to defer and/or abandon capital and operating programmes that deliver services that customers have told us they want—which is not in customers' long-term interests.

7.1 AER DRAFT DECISION

499. The draft decision rejected JGN's proposed rate of return (8.67 per cent), and instead proposed a rate of return of 6.8 per cent. In making this decision, the AER:

- rejected our proposal to use the Fama-French three-factor model, Black CAPM, and dividend discount model to estimate the return on equity, instead using the Sharpe Lintner Capital Asset Pricing Model (**SLCAPM**)
- accepted our proposed terms for the returns on debt and equity (of 10 years)
- rejected our proposed equity beta (0.82) and market risk-premium (7.21 per cent) parameters, and our proposed credit rating (BBB)
- accepted our proposed trailing average return on debt method
- rejected our proposed return on debt transition method, including our method for annually updating the return on debt and nominating the averaging period used to apply it, instead adopting a simple average of the Bloomberg and Reserve Bank of Australia (**RBA**) and averaging periods to be set in the final decision.

7.2 JGN RESPONSE TO THE DRAFT DECISION

7.2.1 RETURN ON EQUITY

500. The rules require that the return on equity be estimated such that it contributes to the achievement of the rate of return objective, having regard to prevailing conditions in the market for equity funds. The rules also require that regard be had to relevant estimation methods, financial models, market data and other evidence.

501. The method adopted by the AER in its draft decision will not result in a cost of equity that is consistent with the rate of return objective. The AER's method involves the following errors:

- *one superior model*—the AER's foundation model approach appears to proceed on the incorrect assumption that one return on equity model will be superior to others. By seeking to identify one model that is superior to others, the AER has asked itself the wrong question. The proper inquiry is whether the rate of return objective is more likely to be promoted by use of one model alone or a combination of models
- *SLCAPM as the superior model*—the AER has erred in concluding that the SLCAPM is superior to other relevant return on equity models
- *bias in the SLCAPM*—the AER has incorrectly concluded that its application of the SLCAPM will deliver an unbiased return on equity estimate. Alternatively, to the extent that the AER acknowledges that the SLCAPM estimate will be biased, it has failed to properly account for this bias
- *regard to relevant evidence*—the AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence—specifically, the AER has identified certain material as relevant but then failed to give it any meaningful role in its estimation of the return on equity. This is in large part due to the convoluted process used by the AER for assessing evidence, whereby different pieces of relevant evidence are considered in different ways at different stages of the process. For some pieces of evidence, the AER has applied a *de facto* persuasive evidence—requiring persuasive evidence to depart from a previously adopted method or parameter value. At the same time, in several cases, the AER's method and reasons for rejecting this other evidence (or relegating it to an indirect role) are illogical and unreasonable. For example, the AER's concern that the dividend discount model (**DDM**) leads to 'very high' estimates (relative to the SLCAPM) reflects an unreasonable treatment of this evidence
- *equity beta estimate*—the AER has erred in its estimation of the SLCAPM equity beta. Neither the AER's range, nor its point estimate, are supported by empirical evidence
- *same equity beta applied to gas and electricity networks*—the AER has erred in concluding that gas transmission and electricity networks face the same or very similar risks to gas distribution networks—this is not supported by the evidence before the AER
- *adjustment for SLCAPM deficiencies*—an implicit or necessary finding made by the AER is that adopting the top of its range for the SLCAPM equity beta will adequately correct for any bias or other deficiencies in the SLCAPM. There is no evidentiary basis for this finding and this range was determined independently of any estimate of low beta bias in the SLCAPM
- *market risk premium evidence*—the AER has failed to take into account relevant and current evidence in relation to the market risk premium (**MRP**), and therefore its estimate of this parameter will not reflect prevailing market conditions
- *role of Wright approach*—the AER has misinterpreted evidence from the Wright approach, by treating this as an alternative implementation of the CAPM rather than as evidence in relation to the MRP

- *imputation credit adjustment*—the AER's method of adjusting for the value of imputation credits is incorrect and is inconsistent with the adjustment for imputation credits that is embedded within the AER's post-tax revenue model (**PTRM**). As a result, the AER's return on equity estimate is not consistent with the estimate of the value of imputation credits.
- *consistency with other market evidence*—the AER has erred in concluding that its return on equity estimate is consistent with other market evidence.

502. The correct approach to estimating the return on equity is as set out in our initial proposal, which is consistent with the rate of return objective. Our proposed approach is to:

- identify relevant return on equity models
- identify relevant evidence which may be used to estimate parameters within each of the relevant return on equity models
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence
- separately estimate the required return on equity using each of the relevant models
- synthesise model results to derive an estimate of the required return on equity.

503. In relation to the last step, JGN considers that at least equal weight should be given to the results of other return on equity models (besides the SLCAPM), given the relative strengths of these models.

504. Further detail on our return on equity proposal is set out in appendix 7.1. Supporting expert reports are provided as appendices 7.2 to 7.9.

7.2.2 RETURN ON DEBT

505. The rules require that the return on debt be estimated such that it contributes to the achievement of the rate of return objective. The rules also require that regard be had to relevant estimation methods, financial models, market data and other evidence.

506. The method that the AER proposes to adopt in its draft decision will not deliver a return on debt estimate that contributes to the achievement of the rate of return objective, as required by the rules.[280] The AER's approach is affected by critical errors of fact and logical inconsistencies, including:

- *setting the credit rating*—the AER has erred in its determination of the benchmark credit rating, by:
  - *for all energy networks*—setting the credit rating for energy network businesses at BBB+ contrary to empirical evidence, and
  - *for gas distribution networks*—applying the same credit rating for all energy network businesses on the basis that the risks faced by electricity networks, gas transmission and gas distribution businesses are 'sufficiently similar'. This is not supported by the evidence before the AER. Gas distribution network business like JGN are more risk exposed than electricity network business and gas transmission pipelines. Further, evidence of actual credit ratings shows that gas distribution networks tend to have lower credit ratings than other energy networks businesses.

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280 NGR, rule 87(8).

- *selecting future averaging periods*—the AER has erred in requiring that JGN nominate its averaging periods for the return on debt before the access arrangement period commences rather than adopting JGN's proposed approach to selecting averaging periods. The AER's proposed approach in this regard is in error in circumstances where JGN's proposed approach:
  - minimises any difference between the allowed return on debt and the return on debt of a benchmark efficient entity
  - allows greater debt management flexibility, and
  - reduces the risk of averaging periods becoming known.

  If averaging periods are locked in too far in advance, there is a risk of misalignment between the averaging period that is locked in and the period over which a benchmark efficient entity would refinance its debt (and therefore misalignment between the return on debt that is estimated using the locked in averaging period, and the return on debt of a benchmark efficient entity)

- *selecting curves in the future*—the AER has erred by pre-determining that a simple average of fair value yield estimates from Bloomberg and the RBA will provide a better estimate of the return on debt, whereas at the time of estimation that may not be correct. A method that selects the data source that fits reported bond yields at the time of estimation, if there is material divergence between the sources, will better achieve the rate of return objective
- *extrapolating the curves*—the AER has erred in the method proposed for extrapolating the RBA and Bloomberg curves and its proposed method for forecasting inflation.
- *transitioning to the trailing average*—in light of the new analysis and evidence presented in the draft decision in relation to efficient financing practice under the previous regulatory approach, it would be an error for the AER to adopt the rate of return guideline (**the guideline**) approach to transitioning to the trailing average. The guideline approach to the transition would create a mismatch between the allowed return on debt and the required return on debt for the benchmark efficient entity. This mismatch is now significant, due to changes in market conditions since JGN submitted its initial proposal. In particular, this mismatch has been exacerbated by the substantial reduction in debt yields since JGN's initial proposal.
- *adopting a fixed principle for the transition*—the AER has erred by rejecting JGN's proposed fixed principle for retaining the trailing average approach across periods, failing to recognise the benefits to stakeholders of committing to this approach and despite stating its intent (in the guideline) to retain it across periods in any case.

507. Given the AER's findings in relation to efficient debt financing practices under the previous on-the-day approach, the correct approach to estimating the return on debt is as set out in JGN's initial proposal and supporting submissions with a revised approach to debt as set out below. That is:

- *benchmark*—using a 10-year term-to-maturity and a BBB credit rating for estimating the return on debt.
- *transition*—using a hybrid to trailing average transition which transitions the risk-free rate over a ten year period from the rate on the day to a trailing average whilst the debt risk premium (**DRP**) is simply rolled forward as a trailing average.
- *data source*—using a four step method for selecting the appropriate data source in the first measurement period (Steps (b)–(e) below) and a five step method for selecting the appropriate data source in each future measurement period:

  a) calculate the difference in estimates produced by the extrapolated fair value yield estimates from Bloomberg and the RBA:

i) if the difference is less than 60 basis points,[281] the estimate produced by the simple arithmetic average of extrapolated fair value yield estimates from Bloomberg and the RBA (extrapolated in accordance with the SAPN method, as recommended by CEG) is used

ii) if the difference is 60 basis points or greater, move to step (b)

b) identify all relevant third party return on debt data series (e.g. Bloomberg FVC or BVAL), the RBA or CBASpectrum)

c) estimate the return on debt for each data series, and an average of the available data series, for that averaging period

d) identify relevant bonds to compare each estimate against and their yields over the averaging period that meet the predetermined objective criteria, and

e) select the return on debt estimate (or combination of estimates) that best fits the sample of bonds identified in step (d).

508. Further detail on our return on debt proposal is set out in appendix 7.10. Supporting expert reports are provided as appendices 7.11 and 7.13.

7.3 JGN RESPONSE TO CHANGED CIRCUMSTANCES

7.3.1 RETURN ON DEBT TRANSITION

509. In our initial proposal we adopted the trailing average approach and transition set out in the guideline, on the proviso that this approach is applied properly and results in reasonable estimates of the return on debt for the benchmark efficient entity.

510. In light of recent changes to debt yields and the AER's findings on current efficient debt financing practices (noted above), it is now clear that the transition in the guideline will not result in reasonable estimates of the return on debt for the benchmark efficient entity. Rather, under that transition, there will be a material mismatch between the allowed return on debt and the required return on debt for the benchmark efficient entity.

511. Since our initial proposal, the on the day DRP has dropped by over 70 basis points, even though the DRP of the benchmark efficient entity has not and is now materially higher. This means that if the return on debt allowance were set using the current rate on the day DRP—as it is under the AER's proposed transition—that the benchmark entity would under-recover its efficient financing costs by about $60M over the next AA period and would need to cut back operating and capital expenditure to ensure it could deliver the returns required by its debt and equity holders.[282] This same situation applies to JGN directly and would mean we cannot deliver the service outcomes that our customers want and value.

512. Our revised proposal overcomes this mismatch—and the resulting negative customer impact—by adopting a hybrid to trailing average transition where the DRP reflects the efficient debt financing practices described in the draft decision. Further detail on this proposal is set out in appendix 7.14.

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[281] The 60 basis point value is set to align with the one per cent revenue threshold set out in the NGL. A 60 basis point difference between the two curves means that each curve is either 30 basis points higher or lower than the average of those two curves. Moving from that average to either curve corresponds to a $5.4M annual revenue impact—which is about one per cent of JGN's forecast building blocks revenue. The $5.4M is calculated as $5.4M = 30 basis points x $3B RAB x 60 per cent.

[282] The $60M is calculated as: 70 basis points x $3B RAB value x 60% gearing x 5 year = $63M. This estimate is conservative because the average RAB over the period is above $3B and the difference between the current rate on the day DRP and the 10 year trailing average DRP is greater than 70 basis points.

7.4 REVISED PROPOSAL

513. Our revised rate of return proposal is set out in Table 7–1. Our revised WACC model is provided as appendix 7.15.

Table 7–1: JGN's proposed WACC

Parameters	JGN proposal (per cent)
Return on equity	9.87
Return on debt	5.33
Inflation	2.55
Leverage	60.00
Gamma	25.00
Corporate tax rate	30.00
Nominal vanilla WACC	**7.15**

(1) Return on debt, return on equity, and nominal WACC are estimated using data from the sample averaging period of the 20 business days to 30 January 2015 (inclusive). These estimates will update for JGN's final averaging period (19 January–16 February 2015), once RBA data is available in March 2015.

(2) Gamma is discussed in chapter 8.

(3) Values may not add due to rounding.

8. COST OF TAX

Box 8–1 Key messages – cost of tax

The draft decision broadly accepted JGN's cost of tax method, including how to determine the tax asset base, tax depreciation and the applicable corporate tax rate of 30 per cent.

We are very concerned with the AER's approach to estimating the value of imputation credits (gamma). In order to promote the NGO, the value for gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate).

The way that imputation credits are accounted for in the building block framework will ultimately impact on returns for equity-holders—if the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers.

The method adopted by the AER in its draft decision will not result in an estimate of gamma that reflects the value that equity-holders place on imputation credits. Like the WACC, gamma should reflect a market valuation. The AER's estimate of gamma ultimately does not meet the requirements of the NGR.

We would encourage the AER to closely consider the relative merits of the two positions on gamma and the expert evidence we have presented to support our proposed value of 0.25, as a better estimate than 0.4.

8.1 AER DRAFT DECISION

514. The draft decision accepts JGN's proposed method for calculating the corporate income tax allowance, including our proposed tax depreciation method and depreciation rates and the value of the 1 July 2015 opening tax asset base (**TAB**) (with minor adjustment).[283]

515. The AER adjusted the values of a number of inputs to the corporate income tax calculation including the values of gamma and other building block components. As a consequence, the AER's adjusted estimate of corporate income tax allowance is substantially below that proposed by JGN.

516. The AER determined a value of 0.4 for the value of imputation credits (or gamma), which is lower than the value in the rate of return guideline (0.5), but higher than that proposed by JGN (0.25). The AER selected 0.4 from a range of 0.3 to 0.5.

8.2 JGN RESPONSE TO THE DRAFT DECISION

517. The AER has accepted our proposed method of estimating the net cost of corporate income tax, and our revised proposal reflects this. The change to the value of imputation credits is dealt with below. Changes to other building block components that give rise to differences in the net cost of corporate income tax are dealt with in other chapters of this response

283 AER, *JGN 2015-20 access arrangement draft decision,* 27 November 2014, p. 8-10.

8.2.1 VALUE OF IMPUTATION CREDITS

518. The Rules require an estimate of "the value of imputation credits".[284]

519. In order to promote the NGO, this must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate). The way that imputation credits are accounted for in the building block framework will ultimately impact on returns for equity-holders—if the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers.

520. The method adopted by the AER in its draft decision will not result in an estimate of gamma that reflects the value that equity-holders place on imputation credits. The AER's method involves the following errors:

- **Definition of theta.** The AER's revised definition of theta—which seeks to exclude the effect of certain factors on the value of imputation credits—is conceptually incorrect and inconsistent with the requirements of the NGR.
- **Role of equity ownership rates.** The AER incorrectly uses equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, equity ownership rates will only indicate the maximum set of investors who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors.
- **Estimates of equity ownership rates.** The AER has erred in its interpretation of the equity ownership data—the ranges used by the AER for the equity ownership rate are inconsistent with the evidence in the draft decision.
- **Role of redemption rates.** The AER uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value.
- **Factors that affect market value studies.** The AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk—which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors.
- **Interpretation of market value studies.** The AER has erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed by JGN. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits.
- **Distribution rate for listed equity.** As well as (correctly) observing that the market-wide distribution rate is 0.7, the AER has also relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample.
- **Estimate of gamma.** The AER's ultimate conclusion as to the value for gamma is inconsistent with the evidence presented in the draft decision, including the AER's own analysis of the equity ownership rate and redemption rate—these measures show that the AER has overestimated the value of imputation credits.

521. The correct approach to estimating gamma is as set out in JGN's initial proposal. That is:

- estimating the distribution rate using ATO data

[284] Rule 87A.

- estimating theta using market value studies—these studies are the best available method for deriving a point estimate of gamma, and
- adopting this approach leads to a conclusion that the best estimate of gamma is 0.25.

522. Further detail on our response to the draft decision on gamma is set out in appendix 8.1. Supporting expert reports from SFG and NERA are provided as appendices 8.2 and 8.3 respectively.

8.3 OUR REVISED PROPOSAL

523. Our revised proposal for gamma is 0.25. This combines a distribution rate of 0.7 with an estimate of theta of 0.35.

9. INCENTIVE MECHANISMS

Box 9–1 Key messages – incentive mechanisms

We are pleased that the draft decision accepts our proposal to introduce an opex efficiency carryover mechanism. This will provide additional confidence that we are incentivised to manage our opex efficiently, beyond our business-as-usual incentive to ensure our costs remain as low as possible to support gas affordability.

When designing an incentive mechanism it is important to specify it correctly in order to ensure that benefits and costs are not inappropriately transferred between us and our customers.

A key specification is to properly take into account how our opex changes due to network and customer growth. We are concerned that the AER considers this adjustment 'unnecessarily complex'. We think it's more important that customers' money is not efficiently allocated simply to avoid having to undertake a calculation exercise. Indeed, we think the calculation exercise is relatively simple compared to the complex evaluations the AER undertakes as part of normal operations.

9.1 AER DRAFT DECISION

524. The draft decision approves the application of an opex efficiency carryover mechanism (**ECM**) to JGN, through the inclusion of a fixed principle in the AA.

525. The draft decision mostly accepts JGN's proposed adjustments and exclusions, although some revisions are required as summarised in Table 9–1.

Table 9–1: ECM adjustments and exclusions – summary of draft decision

JGN's initial proposal	Draft decision
Exclusions	
Determined pass through amounts	Partially accept – add to forecast opex rather than remove from actual opex. No financial consequence of AER's alternative method, simply a preference.
UAG costs	Accept
Licence fee costs	Accept
Debt raising costs	Accept
Carbon costs	Accept
Cost of any relevant tax	Accept
Any other agreed exclusions	Reject – AER limited discretion (not subject to agreement, must be to customers' benefit)
Adjustments	
Scale of activities (demand growth)	Reject – risk considered symmetrical and adjustment to be unnecessarily complex
Capitalisation policy changes	Accept

9.2 JGN RESPONSE TO THE DRAFT DECISION

526. JGN welcomes and accepts the AER's decision to apply an ECM to JGN's opex in the 2015-20 AA period. An ECM provides JGN an additional incentive to consistently seek opex efficiencies. This is in our customers' long-term interests because it reinforces the competitive discipline on us and ultimately puts downward pressure on gas bills. Our Customer Council also expressed support for an ECM applying to our opex.

9.2.1 ADJUSTMENTS AND EXCLUSIONS

9.2.1.1 Determined pass through amounts

527. We accept the draft decision approach, recognising it has no material consequences for customers.

9.2.1.2 Any other agreed exclusions

528. JGN notes the AER's concern about the proposed requirement for JGN agreement before additional categories are excluded from operation of the ECM scheme. JGN and AER officers have engaged further on this issue since the draft decision.

529. JGN's revised proposal therefore contains drafting which JGN considers takes into account the AER's concern and also provides for ex-ante consultation (as part of the AER's usual consultation in respect of revisions to apply to AAs) on the exclusion of other cost categories that the AER considers may not promote the NGO.

530. We understand from discussions and correspondence with AER staff following the release of the draft decision that while the AER would generally consult on these matters, it would be concerned if the AA bound future AER decision-makers to this consultation via their inclusion in the ECM fixed principle. While we have difficulty with the relevance of this concern—noting the uncertainty created by the AER's approach creates a risk of inefficient investment in the network—we propose an approach that may provide a "middle-ground" solution. This approach involves an express exclusion of the consultation process as a fixed principle (see clause 12.2 in the revised AA). Thus, while the remainder of the ECM is expressed as a fixed principle, as approved by the AER in its draft decision, the clause dealing with the exclusion of other cost categories and the consultation process around that is not a fixed principle .

9.2.1.3 Scale of activities (demand growth)

531. We do not accept the AER's rejection of our proposal that carryover amounts should take into account actual changes in demand growth.

532. The draft decision states that it is unnecessarily complex to adjust forecast opex ex-post where demand does not equate with expectations. We challenge the view that the adjustment is both complex and unnecessarily complex.

533. A demand adjustment is accepted practice and is applied by the AER to the electricity and gas distribution businesses it regulates. All it requires is to take the final opex model and replace forecast demand with actual demand—which is very simple—and then extract the updated opex forecast. This is far less complicated than most other adjustments undertaken as part of the regulatory process, for example the annual cost of debt update as part of the tariff variation mechanism.

534. The demand adjustment would be *unnecessarily* complex if the administrative cost of making the adjustment outweighed the allocative efficiency benefit of making the adjustment. Not making the adjustment could see the inefficient misallocation of millions of dollars between JGN and our customers. It is considered highly unlikely that the scale of this allocative inefficiency would be outweighed by the administrative cost of undertaking the adjustment. Therefore, in our view, the draft decision's claim that the adjustment is unnecessarily complex is incorrect.

535. JGN notes that the AER's objective in incentive mechanism design should be to ensure that our incentives are calibrated to best ensure our customers' long-term interests are supported. In the case of the ECM we seek to provide additional productive efficiency incentives on JGN to minimise costs in every year of the AA period and share the savings with our customers over successive AA period. Clearly, having incentives to efficiently out-perform a properly scoped expenditure forecast (with regard to actual levels of customer numbers and demand) will best achieve this productive efficiency incentive objective. Any perceived complexity associated with this adjustment will have no incremental cost. This is because the model is already prepared as part of this determination and the updated demand data is an existing rule requirement[285] to be submitted in the subsequent AAI. Therefore a cost benefit analysis of the incentive benefits against any complexity costs would favour including this adjustment to achieve aligned incentives.

9.3 JGN RESPONSE TO CHANGED CIRCUMSTANCES

536. Our ECM opex forecast reflects the opex forecast updated for the changed circumstances set out in chapter 5.

9.4 REVISED PROPOSAL

537. For the reasons outlined in section 9.2, JGN's revised ECM proposal is largely consistent with our initial proposal. The revised ECM—updated for the revised ECM opex forecasts—is expressed as a fixed principle in section 12 of the revised AA except for the part of the ECM dealing with the exclusion of other cost categories from the operation of the ECM and the consultation to be conducted by the AER in respect of those other cost categories.

[285] Rule 72(1)(d).

10. TOTAL REVENUE AND PRICE PATH

Box 10–1 Key messages – total revenue and price path

JGN has determined its revised total revenue requirement using the building block approach (in accordance with rule 76 of the NGR). JGN's total revenue requirement for the next AA period is $2.45B. This will allow us to deliver the levels of safety and services valued by our customers over the next AA period while prudently balancing our cost and price pressures into future AA periods.

JGN welcomes the AER's willingness to accommodate price path options that best meet customer preferences and the NGO.

Our customers are clear in telling us that retail price stability—and not distribution price stability—is key for them.

Therefore, our revised price path for reference services best smooths our required revenue to better promote retail price stability over the next AA period than provided for by the draft decision. This will best offset some of the increases in end-retail prices resulting from wholesale gas price pressures and will best meet customer preferences. This is consistent with the NGO as allocative efficiency and efficient use will necessarily be driven by customer choices about how they use gas, and those choices are a function of retail *not* network prices.

Should the AER adjust our revenue from this proposal, a price path that gives best effect to this preference would be one that best mitigates expected increases in wholesale gas prices by providing year on year decreases in end-retail prices. This will be achieved by ensuring our price decreases occur when wholesale prices are expected to increase in the period between now and 2018/19 as forecast by Core Energy and accepted by DAE and the AER.

10.1 AER DRAFT DECISION

10.1.1 REVENUES

538. The draft decision proposes that JGN be allowed significantly lower revenue that we proposed in our initial proposal. The main reasons for the difference in total revenue are the AER not approving JGN's proposed capex, rate of return and gamma.[286]

539. The AER's proposed revenue requirement is shown in Table 10–1.[287]

Table 10–1: Draft decision on JGN's smoothed total revenue and X factors for the 2015-20 AA period ($million, nominal)

Building block	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	213.72	222.91	231.62	239.13	244.53	1,151.91
Regulatory depreciation	66.04	77.77	90.84	101.76	88.52	424.94
Operating expenditure	160.03	163.49	168.56	177.64	180.87	850.59
Corporate income tax	9.00	10.49	12.69	15.06	13.23	60.47

286 AER, *JGN 2015-20 access arrangement draft decision – overview*, 27 November 2014, p 10.

287 AER, *JGN 2015-20 access arrangement draft decision - overview*, 27 November 2014, p. 24.

Building block	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Building block revenue – unsmoothed	437.63	451.36	467.06	482.46	464.79	2,303.30
Building block revenue – smoothed	472.98	464.23	456.64	452.05	451.12	2,297.02
X-factor	(23.44%)	(2.09%)	(2.09%)	(2.09%)	(2.09%)	n/a
Inflation forecast	2.55%	2.55%	2.55%	2.55%	2.55%	n/a
Nominal price change	**(21.48%)**	**0.40%**	**0.40%**	**0.40%**	**0.40%**	**n/a**

10.1.2 PRICE PATH

540. The draft decision price path contains a nominal price decrease in 2015-16 of 21.48 per cent followed by 0.40 per cent nominal price increases in the remaining four years of the next AA period. The draft decision indicates that this would:

- align unsmoothed building block costs with smoothed revenue
- align final year unsmoothed and smoothed revenue within 3 per cent to minimise price shocks at the start of the next AA period, in line with JGN's stated objectives and feedback from customers to JGN
- balance these considerations where they conflict, including minimising price changes from year-to-year within the period.

10.2 JGN RESPONSE TO THE DRAFT DECISION

10.2.1 REVENUES

541. JGN proposes allowed revenues that reflect the building blocks proposed in our revised AA proposal. A reasonable opportunity to recover these allowed revenues also requires our demand forecasts to be approved.

10.2.2 PRICE PATH

542. We believe that the AER has an opportunity to use its final decision price path to better meet customers' preferences and promote the NGO in a more preferable manner.

543. We agree with the AER that we should seek to minimise price shocks. However, where the AER has sought to minimise price shocks at the start of the subsequent 2020-25 AA period, this has focussed on a particular year and our distribution prices *only*. It has not taken into account expectations for end-retail prices across the duration of the period. It is well-accepted[288] that these end-retail prices will be trending upwards due to the expected doubling in the wholesale price of gas from 2016.

544. JGN has revisited its engagement with our customers on the price path issue in preparing this response to the draft decision. Customer feedback was clear that:

[288] See for example AER, *State of the Energy Market,* 2014, p. 98. Deloitte Access Economics has also accepted this in its review of JGN's demand forecast.

- rising gas prices and affordability are a concern, particularly for those customers vulnerable to price shocks, both of which are a function of the end-retail price and not just JGN's distribution prices
- stability of end-retail prices over the next five years should be the key driver, rather than other possible options such as steep price decreases followed by steep or steady increases.

545. The lever the AER can use to achieve smooth end-retail prices is to align JGN price decreases in 2016-17, 2017-18 and 2018-19, when the wholesale price is expected to materially rise. This is what we have sought to achieve with our revised price path.

546. We tested this with our customer representatives and other stakeholders at our February 2015 Customer Council. We provided two price path options for comparison to the AER's draft decision price path shape:

- the first option included a smaller P_0 and small ongoing real end-retail price decreases for residential customers
- the second option provided an even smaller P_0 and more substantial ongoing end-retail price decreases.

547. Figure 10–1 compares end-retail bill estimates using these three scenarios.[289] It shows the year on year percentage change in an average residential customers end-retail bill. Our customers told us that both options were preferable to applying the AER draft decision price path shape.

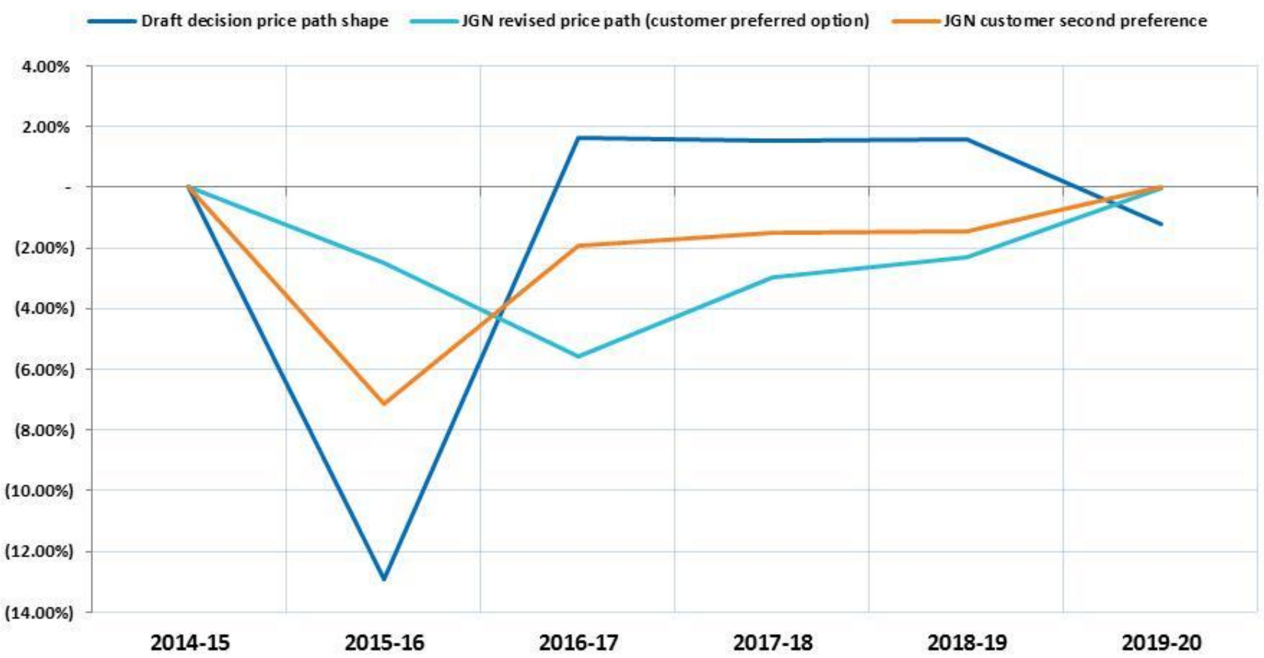
548. Our customers also concluded the second option was sensible and preferable given the uncertainty of when wholesale price increases may occur and the degree to which they might increase—a price path that allows 'headroom' of ongoing real decreases reduces the possibility for volatility. This is the JGN revised price path line in Figure 10–1. AGL have told us our proposed price path is a better outcome for customers.

549. Figure 10–1 shows that JGN's proposed price path would best target JGN's price decreases in years when wholesale price increases are forecast. This would provide for the least volatile end-retail prices for our residential customers, based on current expert forecasts[290] for wholesale gas prices. This is the approach we have taken in section 10.3.

289 All three price paths are based on our revised proposal revenues.

290 Core Energy, Gas demand and customer forecasts, Jemena Gas Networks | NSW Gas Access Arrangement 2015-20, April 2014 p. 70. (JGN, *2015-20 access arrangement information - appendix 5.1*, 30 June 2014).

Figure 10–1: Average residential customer estimated real gas bill percentage change



550. Adopting the AER's price path shape, by having a steep decrease in 2015-16 followed by three years of real end-retail price increases with a final year decrease, would forgo a critical opportunity to give full effect to meeting the clear customer preference for *end-retail price* stability—especially as it would include nominal increases in the period when wholesale prices are expected to double.

551. We also acknowledge the AER's concern regarding cross-period price stability.[291] It is not in our customers' interests to have a price shock in 2020-21 (year 1 of the subsequent AA period). It is also not in our interests because it impacts the competitiveness of natural gas as a fuel of choice. We have had to balance price path considerations for 2015-20 with subsequent AA period considerations.

552. We consider our proposed price path, and also a potential alternative that includes a real price decrease in 2019-20, will allow for cross-period price stability. When considering this issue, it is critical to note that:

- unlike in other businesses' price resets, the JGN P_0 adjustment is not an automatic resetting of revenues to costs—year 1 JGN prices (i.e. 2020 prices) are set out in the initial JGN tariff schedule in the AA and can be set taking into account other factors, including NPV revenue smoothing over the full 2020-25 AA period
- the final two years of the 2015-20 AA period include AA submission costs, and these costs will not be included in 2020-21 building block costs
- our customers prefer ongoing real retail price decreases.

553. Following the same process as we are now, JGN would propose for the 2020-2025 AA period (subject to AER approval) year 1 prices and a four-year price path that manages the impacts on customers in a way that best promotes their long-term interests. This would take into account the importance of keeping prices stable over time, which would also maximise the attractiveness of natural gas as a fuel of choice (which is in JGN's interests). This price-setting process would reflect prevailing and expected energy market conditions at 2020,

291 Though JGN notes that, unlike the NER, this is not a prescribed requirement of the NGR.

including the likelihood of gas supply from northern NSW[292] which may put downward pressure on wholesale gas prices. This would reflect a dynamically efficient approach to price setting. The price pressures caused by the structural changes now occurring in the gas market are likely to be greater than any cost shock in the subsequent AA period.

554. Taking these considerations into account, and after listening to our customers and taking into account the AER's feedback, we have adjusted our price path from that in our initial proposal. We feel this strikes a good balance for our customers, as would an alternative price path that includes a real price decrease in 2019-20 (refer section 10.3.2.1).

10.3 REVISED PROPOSAL

10.3.1 TOTAL REVENUE REQUIREMENT

555. JGN has determined its revised total revenue requirement using the building block approach (in accordance with rule 76). The building block components are:

- a return on the projected capital base
- depreciation of the projected capital base
- a forecast of opex
- a forecast of tax.

556. JGN's total required revenues for each year of the next AA period are set out in Table 10–2. Our revised revenue model is provided as appendix 10.1.

Table 10–2: JGN total revenue requirement ($2015, $millions)

Building block	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	215.95	222.34	227.86	232.17	234.13	1,132.45
Return of capital (depreciation)	65.25	75.71	86.49	94.48	79.38	401.30
Opex	160.96	162.99	163.18	167.60	167.14	821.87
Tax	17.20	18.50	20.79	22.93	19.66	99.08
Total revenue	**459.37**	**479.54**	**498.31**	**517.17**	**500.32**	**2,454.70**

10.3.2 PROPOSED PRICE PATH

557. JGN has determined its smoothed price path in accordance with the NGR and customer feedback both prior to and post the draft decision.

558. An important aspect of our proposed price path is the recognition that our customers' long-term interests will be served through us supporting increased economic customer connections to, and use of, our network to lower average prices over time. We can support this by:

292 See section 4.6.2.1.

- providing smoothed real price reductions over the next AA period to help off-set rises in wholesale gas prices
- continuing our volume market tariff structure of minimising fixed charges, and thereby minimising barriers to gas connections recognising gas is a discretionary fuel in NSW
- targeting the reduction in average prices to those customers most sensitive to movements in our network prices i.e. residential customers—this promotes efficient utilisation of our network.

559. Taking customers' and the draft decision feedback into account, we propose the price path in Table 10–3. This price path has been tested with customers and is designed to balance between customer preferences (to have ongoing real decreases to mitigate wholesale price rises and account for the uncertainty of when, and the degree to which, these will occur) and the draft decision desire to return to cost of service in 2019-20.

Table 10–3: Proposed revenues and X-factor ($2015, $millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	NPV
Total building block revenue - unsmoothed	459.37	479.54	498.31	517.17	500.32	2,115.04
Total building block revenue - smoothed	564.81	518.42	473.74	433.60	441.54	2,115.04
X-factor[293]	6.50%	8.24%	8.24%	8.24%	(1.84%)	N/A

(1) Years are from July to June.

560. This price path gives effect to the price changes shown in Table 10–4. This shows that, on average, our network prices in real terms to fall by 6.5 per cent in 2015-16, continue to fall by 8.24 per cent each year until 2019-20, and then rise by 1.84 per cent in 2019-20 to improve aligning revenue with cost of service. This price path is set out in Table 10–3.

Table 10–4: Average annual price changes (Per cent)

	2015-16	2016-17	2017-18	2018-19	2019-20	Cumulative % total
Real price change	(6.50%)	(8.24%)	(8.24%)	(8.24%)	1.84%	(29.38%)
Inflation forecast	2.55%	2.55%	2.55%	2.55%	2.55%	12.74%
Nominal price change	(4.11%)	(5.90%)	(5.90%)	(5.90%)	4.43%	(17.39%)

(1) Years are from July to June.
(2) Nominal price change is calculated as (1+ real price change) x (1 + inflation forecast)-1.

10.3.2.1 A price path with a real price decrease in 2019-20 would also facilitate customers long-term interests

561. Following our engagement with customers on our price path at our Customer Council[294], we also met with AER staff[295] in to discuss how best to balance customers interests with a price path that seeks to return to cost of service in 2019-20 against customers preferences for ongoing real price decreases. We are satisfied that an alternative price path, that provides for a real price decrease in 2019-20, as well as the preceding years, would

[293] Under the CPI-X form of control (represented by the formula (1-X)*(1+CPI)), a positive X-factor is a decrease in average prices.

[294] JGN customer council meeting, 13 February 2015.

[295] We met with AER staff on 19 February 2015.

not be detrimental to customers long term interests should this be the AER's final preference after considering our customer and stakeholder engagement.

10.3.3 CUSTOMER IMPACTS

562. Table 10-5 shows how we have translated the average annual price changes into price changes for individual customer types. This shows:

- the application of our approach to pricing to meet efficiency criteria by targeting savings on key residential markets (refer to our published tariff structures statement)
- a cumulative reduction in network bills of up to 40% for residential customers over the next AA period—equivalent to savings of $563 for a typical residential customer using 15GJ per annum. (excluding impact of inflation)
- an ongoing small real price increase for our largest business customers (demand market) to return to cost-reflective levels.

563. Appendix 10.2 provides our estimated reference tariffs for the period and associated customer outcomes for various customer archetypes. This enables those interested customers to use their own annual consumption levels to estimate their individual impact.

Table 10–5: Individual customer type network price changes

Customer type	Typical network bill 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Cumulative % total	Total network savings over the period
Volume market								
Small residential (15 GJ pa)	$412	(4.88%)	(16.51%)	(13.16%)	(13.16%)	(0.12%)	(40.18%)	$563
Medium coastal residential (25 GJ pa)	$506	(5.07%)	(14.23%)	(12.62%)	(11.16%)	(0.03%)	(36.80%)	$638
Large coastal/medium country residential (50 GJ pa)	$717	(5.57%)	(11.11%)	(11.50%)	(10.21%)	1.68%	(32.17%)	$809
Small I&C (200 GJ pa)	$2,161	(9.40%)	(5.76%)	(8.82%)	(9.77%)	4.44%	(26.63%)	$2,216
Medium I&C (2000 GJ pa)	$17,927	(11.02%)	(2.69%)	(6.29%)	(7.87%)	5.34%	(21.25%)	$16,099
Large I&C (8000 GJ pa)	$56,787	(12.93%)	0.65%	(6.19%)	(6.49%)	5.16%	(19.15%)	$48,461
Demand market								
Average demand customer	n/a	2.5%	2.5%	2.5%	2.5%	2.5%	13.14%	n/a

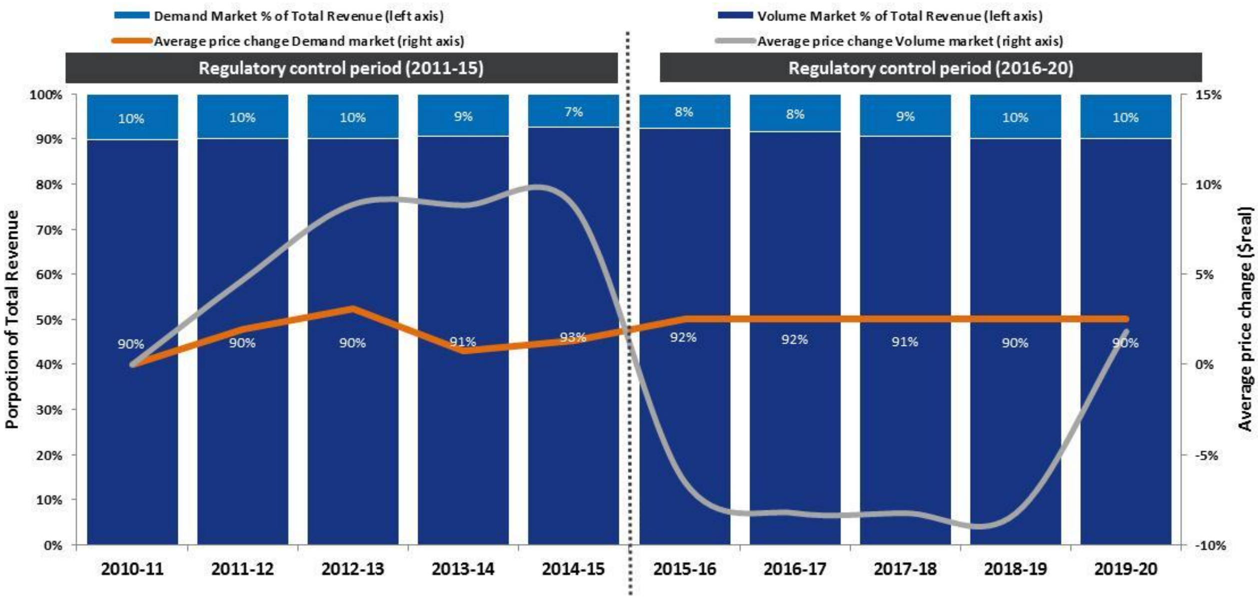
564. We need to provide cost-reflective prices for our customers as well as price in a manner that drives efficient utilisation of the network. This drives the price change we will apply to demand customer's over the next AA period.

565. The demand market was sheltered from price increases in 2011-15 to mitigate the impact of carbon tax on these customers and to enable us to provide stability and certainty to this market. This recognised the benefits of retaining customers so as to spread our fixed costs thinner to all customers' benefit. We were able to do this in a period where relatively higher electricity bills for our residential customers provided a low risk of fuel switching away from gas. Recent and expected price movements mean this is no longer the case. Like for the 2011-15 period, we need to price to retain customers.

566. Figure 10–2 shows the relative price changes for our demand and volume market customers and the resulting proportion of our revenue obtained from each market.

567. We have retained price stability for large businesses across the ten-year period in the graph, which ensures our prices will be cost-reflective by the end of the 2015-20 AA period—best demonstrated by the proportion of revenues obtained from each market returning to historical levels.

Figure 10–2: Price changes for, and revenue from, volume and demand market, 2010-11 to 2019-20



11. REFERENCE TARIFFS AND TARIFF VARIATION

Box 11–1 Key messages – reference tariffs and tariff variation

JGN welcomes the AER's approach to considering our proposed reference tariffs and tariff variation mechanism.

A robust tariff variation mechanism ensures that price changes are administered correctly and efficiently, giving confidence to customers that the prices we charge are appropriate.

We consider that improvements can be made in a small number of areas including:

- providing a more streamlined approach to vary, add and remove tariffs that is based on precedent
- adding a fixed principle to allow cross period pass through, for which we have documented supporting reasons and precedent
- clarifying and fixing the detailed drafting of the tariff variation mechanism.

11.1 AER DRAFT DECISION

568. The draft decision accepted a number of elements of JGN's proposal including:

- the application of a weighted average price cap as an appropriate price control formula[296]
- our evidence of efficient prices, including establishment of tariff classes, long run marginal cost[297] and stand alone and avoidable cost[298]
- tariff improvements, including introducing new intermediary tariffs, modifying block sizes, and grandfathering of first response tariff classes[299]
- our approach to allocate revenues and costs to reference services[300]
- our approach to make improvements to our ancillary services[301].

The draft decision did not accept, or required changes to:

- our ability to add or remove tariffs through the tariff variation mechanism, citing a preference to rely on rule 65 of the NGR[302]
- a fixed principle to give effect to cost pass through events from an immediately prior access arrangement (or 'cross period pass through')[303]

296 AER, *JGN 2015-20 access arrangement draft decision – overview*, 27 November 2014, p 23.

297 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 10-16.

298 Ibid, p 10-12.

299 Ibid, p 10-14.

300 Ibid, p 10-11.

301 Ibid, p 10-13 & 10-15.

302 Ibid, p 10-18.

303 Ibid, p 11-22.

- our suite of proposed pass through events and materiality threshold[304]
- make a small number of drafting changes to the AA pass through mechanism
- mandate an independent audit of our gas quantity inputs as part of our annual tariff variation notices.[305]

11.2 JGN RESPONSE TO THE DRAFT DECISION

569. JGN welcomes the AER's approach to assessing our reference tariffs. This approach recognises that gas is a fuel of choice in NSW, with this competition aligning our interests with our customers.

570. JGN has not submitted further evidence on the areas the AER has accepted. Should the AER receive any further evidence from stakeholders on any of these issues, we would appreciate the opportunity to review and make submissions on the evidence in a timely manner.

11.2.1 ABILITY TO ADD OR REMOVE TARIFFS

571. JGN proposed a mechanism to allow the introduction or withdrawal of reference tariffs through the tariff variation mechanism (which provides for AER approval). The AER considers these matters should be conducted via rule 65 of the NGR.[306]

572. JGN agrees that these changes should have AER oversight (and be subject to better facilitating the NGO). For the avoidance of doubt, this process would allow JGN to vary, add or remove tariffs as part of the tariff variation mechanism (which is subject to AER approval) and not via any other process.

573. However, JGN does not consider they are matters that should require a formal variation of JGN's AA under rule 65. This would be administratively burdensome for no additional benefit to customers. JGN envisages that the need for change would be infrequent and driven by the need to respond to customer preferences and to give effect to the NGO. For example, improvements such as the introductions of intermediary tariff classes, could occur as the need arises following customer and stakeholder engagement (through our published TSS process) and AER approval process.

574. JGN considers that the drafting of clause 3.1 of our AA proposal makes sufficient provision for AER oversight given that clause 3.1(b) provides that JGN may vary reference tariffs in the manner contemplated by sub-clauses (i) to (iv) 'in accordance with this clause 3', which in turn invokes the process for AER approval in clauses 3.6 to 3.8.

575. Our revised proposal process is based on precedent within Envestra's approved access arrangement.[307] By enabling addition and removal of tariffs within the AA, rather than reopening it, would also be closer to the process allowed for Victorian electricity network businesses[308] and also that introduced by the AEMC to allow all electricity distributors to make changes to their tariff structures via their tariff structure statements. The AEMC

304 AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 11-19 to 11-22.

305 Ibid, p 11-24.

306 Ibid, p 10-18.

307 Clause 3.1(b) of our AA proposal substantially replicates the final part of clause 4.4.1 of Envestra's current AA.

308 Victorian electricity network businesses have been able to introduce and remove tariffs since 2000. This provision allowed these businesses to introduce the Victorian Government's required time of use tariffs within the current 2011-2015 period without the need to reopen each businesses regulatory determination.

acknowledged that changes to tariffs may need to occur to ensure they respond to changes in the way energy is used.[309]

11.2.2 CROSS PERIOD PASS THROUGH

576. JGN included a fixed principle in its initial AA proposal to allow for cross-period pass throughs[310] (referred to as "cost pass through events from immediately prior access arrangement period"). The draft decision rejected the fixed principle on the basis that JGN did not provide reasons for including it in our AA.

577. Recognition of cross period pass through in our AA would potentially allow the financial impact of an approved cost pass through event that occurs late in one AA period to be addressed in the reference tariffs that apply in the next AA period (as an alternative to adjusting tariffs to pass through all of the cost in the limited time available before the end of the then current AA period). This would arise in circumstances where the financial impact of the relevant event cannot practically be included in reference tariffs in the AA period in which the event occurs, for example, where the cost impact remains unknown for some time, or if the event occurs in the last weeks of the AA period, thus making a tariff variation in that AA period problematic.

578. This is consistent with the year-on-year pass through events (subject to an administrative threshold) and "administrative" pass-through adjustments (not subject to a threshold) that the AER currently approves for JGN under its current AA, save that the years involved span the transition from one AA period to the next.

579. Our primary areas of concern involve circumstances where expenditure is incurred (or savings made) as a consequence of a cost pass through event that occurs:

- in the period after JGN's final annual tariff variation is submitted to the AER, but before the end of the relevant AA period (for example, in the 2015-20 AA period, after JGN submits its annual tariff variation application in March 2019, but before 30 June 2020); or
- in one AA period, but where the cost impact is unknown until the following AA period; or
- in one AA period, where there are cost impacts both in that AA period as well as the next AA period.

580. In the context of the 2015-20 AA period, we consider a cross period pass through fixed principle is required for matters including to:

- give effect to the return of residual cost savings from the repeal of the Clean Energy Act on 17 July 2014 (see further explanation of this issue below)
- enable the tariff variation mechanism to move to t-2 adjustments—required to allow us to bring forward our annual tariff variation notices to 15 March each year, providing more time for AER assessment and retailers to incorporate our prices
- provide a reasonable opportunity for JGN to recover its efficient costs as required in the RPPs in the NGL.[311]

581. JGN has previously:

- provided a description of the move to t-2 adjustments[312] and the change to the tariff variation process[313] in its initial proposal

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309 AEMC, *Distribution Network Pricing Arrangements rule change, final decision*, 27 November 2014.

310 JGN, *2015-2020 Access Arrangement proposal*, 30 June 2014, Clause 3.5.

311 NGL, section 24.

312 JGN, *2015-2020 access arrangement information* , 30 June 2014, p.129.

- engaged with the AER on the need for cross period pass through via a staff meeting on 12 September 2013 and sought clarification on the AER's position[314]
- received a letter from the AER, acknowledging the merits of cross-period pass through and suggesting we include it in our proposal for consideration[315]
- engaged with the AER, IPART, retailers and customers on the approach to return cost savings to customers as a result of the repeal of the Clean Energy Act.[316]

582. JGN understands that the AER may approach with caution the use of fixed principles that bind application of regulatory discretion between regulatory periods. JGN notes however, that in this instance (similar to the ECM which the AER has approved) the fixed principle is necessary to give proper effect to specific aspects of the AER's decision for the current period.

583. For example, given the AER considers that UAG costs should continue to be subject to an incentive scheme where JGN is motivated to minimise these UAG costs, and is only compensated for the actual competitively procured gas price and actual outturn gas quantities, then a fixed principle is needed to ensure that all five years of the AA period are subjected to the desired incentives.

584. Failure to enact this particular fixed principle would result in:

- the AER's decision only applying to UAG costs for three of the five years—there is no incentive reason, nor customer interest facilitation principle, to suggest that such a constraint is more preferable than JGN's proposal
- no mechanism for JGN to pass back the residual savings[317] of $628,221.70[318] to customers as a result of the repeal of the Clean Energy Act.

585. A fixed principle to give effect to cross period pass through would also be consistent with that provided for APA GasNet[319] and specifically allowed for in the National Electricity Rules.[320]

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313 JGN, *2015-2020 access arrangement information*, 30 June 2014, p.130.

314 Refer to Appendix 1.7, JGN, Letter to Sebastian Roberts from Shaun Reardon, *JGN Access arrangement – cross period pass through*, 2 December 2013.

315 Refer to Appendix 1.7, AER, Letter to Shaun Reardon from Sebastian Roberts, *JGN Access arrangement – cross period pass through*, 16 January 2014.

316 This culminated in AER staff confirming its preferred process via email on 24 October 2014.

317 The repeal of the Clean Energy Act 2011 (Cth) on 17 July 2014 removed our carbon liabilities, effective from 1 July 2014. To give effect to this, we voluntarily ceased collecting carbon-related revenue from industrial customers (demand market) from 1 July 2014 and residential and commercial customers (volume market) from 1 August 2014. This was formalised with our 18 November 2014 within-year tariff variation notice that the AER approved in January 2015. Our within-year tariff variation notice also set out that we would return residual cost savings (the July 2014 carbon-related revenue from volume market customers plus gas transmission fugitive emissions and operating costs less a retailer of last resort pass through), including an allowance for time value of money, in our 2015-16 prices. This will appear as a one-off 'Clean Energy Act repeal settlement' tariff component in our 2015-16 tariff schedule (refer Schedule 2 of our AA). This will be a negative tariff component that will be removed from 2016-17.

318 In accordance with our approach set out in our November 2014 within-year tariff variation notice, this includes revenue collected from the volume market during July 2014 from the $0.110/GJ throughput charge ($489,709) plus gas transmission fugitive emissions ($91,696) and operating costs ($31,000) less a pass-through amount for a retailer of last resort event ($14,586) (all in $2015). JGN has adjusted for the difference for the time value of money consistent with a previous AER request for this to be based on the assumption that the relevant adjustments are in end of financial year dollars (30 June) and that the adjustments will be provided for evenly over the financial year (i.e. JGN has applied the adjustment for 0.5 years).

319 APA GasNet, *2013-17 access arrangement*, p. 24.

320 On 2 August 2012, the AEMC made a new electricity rule on 'Cost pass through arrangements for network service providers'. In making its final decision, the AEMC considered that the National Electricity Rules (NER) inadvertently prohibited a Network Service Provider (NSP) from seeking pass-throughs that crossed AA periods. The AEMC considered that allowing cross period pass-through would remove a known anomaly from the NER and enable consistent treatment of pass-through events, whenever they occur. The

11.2.3 DRAFTING CHANGES

586. The AER has made a small number of drafting changes to the tariff variation mechanism. Section 11.3.3 and appendix 1.4 provide JGN's response to these changes.

11.2.4 AUDIT OF GAS QUANTITY INPUTS

587. The AER has added a requirement for annual tariff variation notices to include an independent audit of gas quantity inputs.[321] JGN accepts this change to the AA and has obtained a quote to undertake the audit. As a change to JGN's regulatory obligations, this costs have been included as an opex step change (refer chapter 5).

11.3 REVISED PROPOSAL

588. Our revised proposal gives effect to the elements below.

11.3.1 ABILITY TO VARY, ADD OR REMOVE TARIFFS

589. We have retained a process in our revised AA for the introduction or withdrawal of reference tariffs, consistent with the Envestra precedent, the process available to Victorian electricity network businesses since 2000, and the intent of the recent AEMC rule change for electricity distributors. This enables JGN and the AER to manage the introduction, variation and withdrawal of reference tariffs (should any be required) via AER approval pursuant to JGN's AA, rather than a formal application to vary the AA under rule 65 of the NGR.

11.3.2 CROSS PERIOD PASS THROUGH

590. JGN has retained the fixed principle to give effect to cost pass through events from an immediately prior access arrangement.

11.3.3 DRAFTING CHANGES

591. JGN has made the changes as indicated below and in Appendix 1.4.

11.3.3.1 Tariff variation mechanism

592. The draft decision requires drafting changes to the automatic adjustment factor, including the definitions of real WACC and licence fee factor. Upon review, we consider we can improve the definition of real WACC and note that this also requires subsequent changes to the automatic adjustment factor formula. The licence fee factor should also be adjusted to ensure appropriate compounding. We highlight these here with the full automatic adjustment factor included in Box 15-2 and at schedule 3 of the revised AA.

Real WACC definition

593. The AER has defined realWACC$_t$ as 'per that set out in this draft decision and updated annually within the PTRM'. To give effect to the AER intent, we consider this requires changes (as reflected in Box 15-2) to:

AEMC considered that this was consistent with the revenue and pricing principles such that a NSP is provided a reasonable opportunity to recover at least the efficient costs it incurs in providing network services.

[321] AER, *Draft decision, Attachment 11 – Reference tariff variation mechanism*, revisions 11.2 and 11.3, pp. 11-24 to 11-25.

- the automatic adjustment factor formula to reflect that realWACC is a variable rather than a fixed number—this is given effect by compounding by real WACC in years t and t-1
- the definition of $realWACC_t$ to refer to the AER's final decision rather than the draft decision to ensure the appropriate value is used—this would also be consistent with the definition of X_t
- the definition of $realWACC_t$ to refer to JGN's revenue model as post tax revenue model is an NER-defined phrase.

Licence fee factor definition

594. The AER revision requires L_{t-2} to be defined as:

L_{t-2} is the licence fee factor amount, as defined in the AA, for Financial Year t-2

When t-2 is financial year 2014-15, L_{t-2} is $L_{2014} + L_{2015}*(1+real\ WACC_t)^2(1+CPI_{t-2})$

595. To ensure the licence fee factor formula is accurate, we consider this requires changes (as reflected in Box 15-2) to the definition of licence fee factor when t-2 is financial year 2014-15 to:

- escalate L_{2014}, and not L_{2015}, by compounding by realWACC (not squared as required by the AER) and CPI to make sure all values are in 2015 dollars
- refer to the appropriate realWACC value, which should be the real WACC in financial year 2014-15 (i.e. t-2), and is the real WACC applicable to JGN's current access arrangement period of 8.39 per cent.

596. The definition of CPI in the AA also needs to be broadened to include 2014-15 to enable the L_{t-2} formula to function (the definition previously was limited to 'financial years beginning after 30 June 15'). As December 2014 quarter inflation is known, we have included 2014-15 CPI as a fixed value in the definition.

X factor definition

597. Box 11-2 shows that the definition of X_t in the automatic adjustment factor should refer to JGN's revenue model as we do not have a PTRM. The definition also specifies how updates for the return on debt should occur.

11.3.4 AUDIT OF GAS QUANTITY INPUTS

598. JGN has inserted the requirement to audit gas quantity inputs into clauses 3.6(a)(iv) and 3.7(a)(iv) of the proposed AA.

Box 11–2 Automatic adjustment factor

$$A_t = \frac{(1 + A'_t)}{(1 + A'_{t-1})} - 1$$

where

A'_{t-1} is:

(a) zero when t-1 refers to Financial Year 2015-16; or

(b) the value of A'_t determined in the Financial Year t-1 for all other years

and

$$A'_t = \frac{(L_{t-2} + U_{t-2} + C_{t-2} + T_{t-2})\left[(1 + realWACC_{t-1})(1 + realWACC_t)(1 + CPI_{t-1})\right]}{(1 - X_t)\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

where:

L_{t-2} is the licence fee factor amount, as defined in the AA, for Financial Year t-2

When t-2 is Financial Year 2014-15, L_{t-2} is L_{2014}*(1+$real\ WACC_{t-2}$)*(1+CPI_{t-2})+ L_{2015},

where:

L_{2014} is the licence fee factor amount, as defined in the AA, for Financial Year 2013-14

L_{2015} is the licence fee factor amount, as defined in the AA, for Financial Year 2014-15

$real\ WACC_{t-2}$ is 8.39 per cent

CPI_{t-2} is 1.72 per cent

U_{t-2} is the UAG factor amount, in accordance with the AA, for financial year t-2

C_{t-2} is the carbon cost factor amount, in accordance with the AA, for financial Year t-2

when t-2 is the Financial Year 2014-15 $C_{t-2} = 0$

T_{t-2} is the Relevant Tax factor amount for financial year t-2

$real\ WACC_t$ is as per that set out in the AER's final decision and updated annually within JGN's revenue model

CPI_t has the same meaning as set out in the 2015 AA proposal.

CPI_{t-1} is the value of CPI_t determined in the Financial Year t-1

X_t means the X factor for each Financial Year, determined in accordance with the JGN revenue model, updated for the return on debt in accordance with clause 5.9 of the AA

p_{t-1}^{xy}	has the same meaning as set out in the AA.
q_{t-2}^{xy}	has the same meaning as set out in the AA.

12. PASS THROUGH EVENTS

Box 12–1 Key messages – pass through events

It is important that our customers only pay what is necessary for us to provide the network services that they value. It is also important that we have the funding necessary to provide these services.

We have carefully considered the draft decision, our unique operating environment and our ability to manage unforeseen events in a cost effective way. We have concluded that it is in our customers' long-term interests that we have sufficient ability to recover our efficiently incurred costs, because this will help us maintain the expected levels of network safety and reliability.

Our revised pass through event proposal reflects a balanced consideration of the risks that face our business, and whether we are best placed to manage these risks. This supports allocative efficiency and therefore promotes the NGO and is consistent with the RPPs. We have accepted the AER's draft decision in relation to the regulatory change event and service standard event (subject to some minor drafting issues). We have also accepted the AER's position on our proposed business continuity event; in its place we propose the following events (which draw upon recent regulatory precedent, more specifically define the nature and scope of each event, and also take into account an assessment of the various other risk mitigations available to JGN):

- insurance cap event
- natural disaster event
- terrorism event
- gas supply shortfall event
- insurer credit risk event.

We have not accepted the AER's decision in relation to the network user failure event. JGN agrees that the National Energy Customer Framework (**NECF**) laws may provide coverage in the event of a retailer of last resort (**RoLR**) event due to retailer insolvency (provided that the retailer has failed to meet its payment obligations to JGN – which may not be the case in all insolvency scenarios). However, there are other potential RoLR events, unrelated to retailer insolvency and beyond JGN's ability to control, which are all outside the scope of the retailer insolvency event in rule 531 of the NGR. The network user failure event – as included in JGN's 2010-15 AA and also in JGN's initial proposal for 2015-20 – is designed to address these gaps. We further note that there is currently a rule change proposal before the AEMC that will broaden the definition of "retailer insolvency event" in the National Electricity Rules (**NER**). JGN has revised its proposed cost pass through event to capture the intent of that proposed rule change. Consistent with the proposed rule change, the revised network user failure event is not subject to a materiality threshold.

For similar reasons as those applying to our revised pass through events, we have not accepted the AER's decision on the materiality threshold. We would ask the AER to carefully consider the reasoning we have put forward to support our position that a one per cent threshold (in each year of the AA) does not reflect outcomes that would occur in a workably competitive market.

12.1 AER DRAFT DECISION

12.1.1 PASS THROUGH EVENTS

599. JGN proposed four cost pass through events in its initial proposal to the AER. These are:

- regulatory change event
- service standard event
- business continuity event
- network user failure event

600. In assessing these proposed events for the purpose of its draft decision, the AER took into account matters including:

- the appropriateness of each event as worded in JGN's proposal, having regard to the NGO and the pass-through criteria in the NER[322] - on the basis that, if approved, the event would operate to transfer material cost impacts associated with the event from JGN to our customers
- the desirability of harmonising the wording of JGN's cost pass through events, where practicable, with cost pass through events specified in the NER, as well as events specified in recently-approved AAs of other gas distribution networks
- ensuring cost pass through events are clearly defined and sufficiently specific in their scope
- the level of information provided as to JGN's available means (other than passing through costs to consumers) of managing the impacts of these events.

601. An outline of the draft decision position on cost pass through events is set out in Table 12–1.

Table 12–1: Draft decision position on proposed cost pass through events

JGN event (initial proposal)	Draft decision	Summary reasons
Event is proposed as follows: Regulatory Change Event means a change in regulatory obligation or requirement, or the introduction or removal of a regulatory obligation or requirement, that falls within no other category of Cost Pass Through Event and affects the circumstances of the Service Provider's business, including the manner in which the Service Provider provides the Reference Service;	Event to be revised as follows: Regulatory Change Event means a change in a regulatory obligation or requirement~~, or the introduction or removal of a regulatory obligation or requirement,~~ that falls within no other category of ~~C~~cost ~~P~~pass ~~T~~through ~~E~~event and substantially affects ~~the circumstances of the Service Provider's business, including~~ the manner in which the Service Provider provides the Reference Service; [mark-up showing changes made to event definition relative to the JGN initial proposal]	Minor revisions are proposed to ensure that the definition: • better reflects the NGO and the AER's assessment approach • is consistent with the equivalent events that apply to electricity network businesses under the NER.
Event is proposed as follows: Service Standard Event means a legislative or administrative act or	Event to be revised as follows: Service Standard Event ~~means~~	Minor revisions are proposed, for the same reasons as specified for the Regulatory Change Event, above.

322 Refer to nominated pass through considerations in AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, p 11-11.

JGN event (initial proposal)	Draft decision	Summary reasons
decision that has the effect of: • varying, during the course of an Access Arrangement Period, the manner in which the Service Provider is required to provide a the Reference Service; or • imposing, removing or varying, during the course of an Access Arrangement Period, minimum service standards applicable to the Reference Service; or • altering, during the course of an Access Arrangement Period, the nature or scope of the Reference Service, provided by the Service Provider;	a legislative or administrative act or decision that has the effect of: • ~~v~~Varying, during the course of an Access Arrangement Period, the manner in which ~~the Service Provider~~ Jemena Gas Networks is required to provide a ~~the~~ Reference Service; or • ~~i~~Imposing, removing or varying, during the course of an Access Arrangement Period, minimum service standards applicable to a ~~the~~ Reference Service; or • ~~a~~Altering, during the course of an Access Arrangement Period, the nature or scope of a ~~the~~ Reference Service, provided by ~~the Service Provider~~ Jemena Gas Networks [mark-up showing changes made to event definition relative to the initial proposal]	
Event is proposed as follows: Business Continuity Event means the occurrence of an event that may create, or may lead to, an interruption, disruption, loss and/or crisis in the Service Provider's business for which the Service Provider does not have full insurance, including gas supply shortfall, tsunami, cyclone, pandemic illness and earthquake. For the purposes of this definition, the value of the Service Provider's insurance coverage is the greater of the Service Provider's insurance coverage at the time of the event and the coverage at the time the AER approves this Access Arrangement, with reference to the forecast operating expenditure allowance approved in the AER's final decision and the reasons for that decision;	Event is not approved.	Event is not approved because: • the AER is not satisfied that it is consistent with the NGO • the AER advises its approach to assessing such events "has evolved" • the event is broadly defined and does not identify the specific nature or type of event it is limited to • the event lacks clarity as to the risk management activity JGN will undertake to mitigate the likelihood or impacts of such a broadly defined event • JGN has not provided detail as to whether a prudent service provider could reasonably prevent the events contemplated or mitigate their impact.
Event is proposed as follows: Network User Failure Event means the occurrence of an event whereby a	Event is not approved.	Event is not approved because: • the AER is not satisfied that it is consistent with the NGO • the AER advises its approach to

JGN event (initial proposal)	Draft decision	Summary reasons
User becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another User but excludes costs that could be the subject of a pass through amount pursuant to rule 531 of the National Gas Rules;		assessing such events "has evolved" • with the introduction of the NECF in NSW there is no longer a need to approve a RoLR event for service providers – the AER considers that the "primary costs" incurred by JGN as a result of a retailer becoming insolvent or being unable to supply gas are covered by rule 531 of the NGR and s167 of the National Energy Retail Law.

12.1.2 MATERIALITY THRESHOLD

602. The draft decision did not accept our proposed materiality threshold in favour of the existing threshold of one per cent of revenue.

603. The draft decision did not accept our proposal that no materiality threshold be applied to a regulatory change event that relates to carbon. The draft decision is that the one per cent materiality threshold applies to regulatory change events that relate to carbon.

12.2 JGN RESPONSE TO THE DRAFT DECISION

12.2.1 PASS THROUGH EVENTS

604. In responding to the AER's draft decision, JGN has re-assessed its position on cost pass through events taking into account matters including:

- feedback provided by the AER in its draft decision, as well as further feedback provided to us subsequently by AER staff
- the position on cost pass through events in the AER's recent draft decisions for the Networks NSW electricity distribution businesses (given the AER's draft decision position regarding harmonisation of cost pass through events with the NER), as well as circumstances affecting gas distribution in NSW such that harmonisation with the NER would not promote the NGO or be consistent with the RPPs
- the relevant parts of clause 3 of JGN's initial AA proposal, which provides a robust framework for AER decision-making in relation to cost pass through, including specifying the factors the AER is required to take into account in assessing any cost pass through application, and the materiality threshold that applies
- other available mitigations for the impacts of these events, including RSA provisions and available insurance.

605. JGN proposes the revised events outlined in the following paragraphs.

12.2.1.1 Regulatory change event

606. JGN's accepts the AER's revisions to its regulatory change event definition, subject to the following two drafting-related exceptions:

AER's proposed amending of "Cost Pass Though Event" to "cost pass through event"

607. "Cost Pass Through Event" is a defined term listed in schedule 1 of the AA. Accordingly, in keeping with the drafting convention that applies in the remainder of the document, "Cost Pass Through Event" should be used in the definition of regulatory change event to minimise any uncertainty.

608. JGN raised this minor drafting issue with AER staff on 14 January 2015.

AER's insertion of "substantially" before "affects the manner in which the Service Provider provides the Reference Service"

609. Given that cost pass through arising from a regulatory change event is already subject to the materiality thresholds specified in clauses 3.4(b) and (c) of the AA, JGN submits that if a regulatory change can be demonstrated to have an impact on the provision of the reference service, satisfaction of that materiality threshold test alone should be enough to demonstrate that that event is of sufficient importance to justify cost pass through.

610. The fact that the regulatory change event impacts the provision of the reference service and causes costs to be incurred that are at least one per cent of the smoothed forecast revenue in any year, or 0.5 per cent of the overall smoothed forecast revenue (i.e. has a financial impact of more than $5M in a year, or more than $12.5M over the five year AA period), means that by its very nature the event would have a substantial impact. Hence, given that:

- there is already a clearly defined materiality threshold in clause 3.4 of the AA
- "substantial" and "material", in this context essentially mean the same thing,

the inclusion of wording requiring an event to satisfy both a materiality threshold and then a separate "substantial" impact test, simply creates unnecessary uncertainty and ambiguity.[323]

611. Put another way, if the AER's drafting was accepted, and a regulatory change occurred which JGN could demonstrate was beyond its control and there were no other available means of mitigation, yet had a financial impact on JGN's business that well exceeded the financial threshold, and had a clear and demonstrable impact on the provision of the reference service, JGN would be left without certainty that cost pass through would be available. This is inconsistent with COAG's Best Practice Regulation guidelines, which relevantly state:

> *Where possible, regulatory instruments should be drafted in 'plain language' to* ***improve clarity*** *and simplicity,* ***reduce uncertainty*** *and enable the public to understand better the implications of regulatory measures* (emphasis added).[324]

612. JGN further notes that:

- although all recently-approved gas network AAs have included a regulatory change event, and in each case this event requires the service provider to demonstrate to the AER that the relevant change in regulatory obligation "affects the manner in which the service provider provides reference services", in no case does the relevant AA require the service provider to separately demonstrate the event has a "substantial" impact on the manner of provision of reference services.[325] For regulatory changes, JGN should receive equivalent cost pass through treatment as these other networks

323 See, for example, the Concise Oxford Dictionary (Australian edition), which relevantly defines "substantial" to mean "of real importance or value", and "material" to mean "important, essential, relevant"

324 COAG, *Best practice regulation – a guide for ministerial councils and national standards setting bodies*, October 2007, p. 5.

325 Refer to the current access arrangements of each of APA Gasnet, Envestra (SA), Envestra (Vic) and Multinet.

- given the size of the JGN network relative to these other networks, the cost materiality hurdle that must be cleared by JGN before cost pass through may be sought is significantly greater than the equivalent cost materiality hurdle for each of these other networks (i.e. JGN requires a significantly larger financial impact event before cost pass through may be proposed for the AER's consideration).

613. This results in the following revised event, which JGN proposes for inclusion in its AA:

> ***Regulatory Change Event*** *means a change in a regulatory obligation or requirement that falls within no other category of Cost Pass Through Event and affects the manner in which the Service Provider provides the Reference Service.*

12.2.1.2 Service standard event

614. JGN's accepts the AER's revisions to its service standard event definition, subject to the following three minor-drafting exceptions. JGN raised these minor drafting issues with AER staff on 14 January 2015.

Insertion of "Jemena Gas Networks" in place of "Service Provider" in this definition

615. In keeping with the approach taken in the current 2010-15 AA, JGN has adopted the drafting convention of referring to itself as the "Service Provider" in the 2015-20 AA. Therefore, to minimise any uncertainty – given the use of "Service Provider" in numerous places elsewhere in the AA document, JGN proposes to retain "Service Provider" in this definition, rather than "Jemena Gas Networks".

Deletion of "means" at the beginning of the definition

616. Schedule 1 of the AA lists the defined terms used in the document, in each case followed by "means" or "has the meaning". Accordingly, for consistency, the word "means" should be retained in this definition.

Replacement of "the Reference Service" with "a Reference Service"

617. As there is only one reference service under the AA for the 2015-20 period, JGN submits that its original wording is appropriate, and is consistent with the remainder of the AA document.

618. This results in the following revised event:

> ***Service Standard Event*** *means a legislative or administrative act or decision that has the effect of:*
>
> *(a) Varying, during the course of an Access Arrangement Period, the manner in which the Service Provider is required to provide the Reference Service; or*
> *(b) Imposing, removing or varying, during the course of an Access Arrangement Period, minimum service standards applicable to the Reference Service; or*
> *(c) Altering, during the course of an Access Arrangement Period, the nature or scope of the Reference Service, provided by the Service Provider.*

12.2.1.3 Business continuity event

619. JGN has considered the AER's position in relation to this event, and taking that into account has decided not to proceed with the business continuity event as originally proposed.

620. In place of the business continuity event, JGN proposes inclusion of cost pass through events as specified in Table 12–2 below. As with the business continuity event, these have been drafted to capture "force majeure"-style events, being a type of event that:

- is uncontrollable, in that JGN cannot reasonably or practicably mitigate or prevent the full impact of the event
- has a low probability of occurrence and is unpredictable
- should it occur, has a potentially material financial impact on JGN
- cannot be effectively insured, in the sense that external insurance is either unavailable or, where available, it is not efficient for JGN hold insurance to fully mitigate the risk in all possible circumstances
- carries with it risks that are not fully mitigated through other aspects of JGN's AA proposal.

621. Having regard to the above, JGN considers that cost pass through is the most appropriate and cost effective means for managing risks associated with this type of event.

Table 12–2: Proposed events to replace Business Continuity Event

Pass Through Event	Proposed definition
Insurance Cap Event	**Insurance Cap Event** means an event where: (a) the Service Provider makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy; (b) the Service Provider incurs costs beyond the relevant policy limit; and (c) the costs beyond the relevant policy limit increase the costs to the Service Provider of providing the Reference Service. For this Insurance Cap Event: (a) the relevant policy limit is the greater of: (i) the Service Provider's actual policy limit at the time of the event that gives, or would have given, rise to the claim; and (ii) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the Access Arrangement Period in which the relevant insurance policy is issued; (b) a relevant insurance policy is an insurance policy held during this Access Arrangement Period or a previous period in which access to the pipeline services was regulated; and (c) the Service Provider will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party of the Service Provider in relation to any aspect of the Network or the Service Provider's business.
Terrorism Event	**Terrorism Event** means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear);
Natural Disaster Event	**Natural Disaster Event** means any fire, flood, earthquake or other natural disaster;
Gas Supply Shortfall Event	**Gas Supply Shortfall Event** means an event outside of the control of the Service Provider which: (a) causes the Service Provider (acting reasonably in the circumstances) to take action to safely manage the impact or potential impact on the Network of materially insufficient gas being available for injection into the Network, including in the circumstance where the

Pass Through Event	Proposed definition
	pressure of Gas at any Receipt Point drops or threatens to drop below the minimum receipt pressure at that Receipt Point; and (b) results in an interruption or reduction in the provision of the Reference Service.
Insurer Credit Risk Event	**Insurer Credit Risk Event** means the insolvency of an insurer of the Service Provider, as a result of which the Service Provider: (a) incurs materially higher or lower costs for insurance premiums than those allowed for in the AER's final decision in relation to this Access Arrangement; or (b) in respect of a claim for a risk that would have been insured by the insolvent insurer, is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or (c) incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer. For the purpose of this event, an event is considered to materially increase costs where the event has a cost impact of either: (d) in at least one of the Financial Years of the Access Arrangement Period that the costs are incurred, at least one per cent of the smoothed forecast revenue specified in the Access Arrangement Information for the corresponding year that the costs are incurred; or (e) in total over the 2015-20 Access Arrangement Period, equal to or greater than 0.5 per cent of the smoothed forecast revenue specified in the Access Arrangement Information.

622. Each of the above event definitions, which are proposed to be included in schedule 1 of JGN's AA:

- clearly defines the nature and scope of the event
- is consistent with recent regulatory precedent (other than the Gas Supply Shortfall Event, which as noted below is an event derived from the particular gas supply circumstances of NSW and the ACT).

623. Further details about each of these proposed events is set out below.

Insurance Cap Event

624. Consistent with the position taken by other gas and electricity networks businesses recently[326], JGN considers that the most efficient means of managing our exposure to the risk of liabilities crystallising over and above our insurance levels is via cost pass through. This is also consistent with the position taken for the 2010-15 AA period, through the business continuity event and general pass through event in JGN's AA (neither of which are proposed for inclusion in JGN's 2015-20 AA).

625. Given the absence of these two events, JGN proposes an insurance cap event to properly manage its exposure to such risks. The rationale for proposing an insurance cap event is because external insurance for risk events of this nature (non-routine, but potentially material impact) may not be available or, if available, is not available on terms and conditions (including price) that are reasonably commercial, such that full mitigation via insurance is not an efficient outcome for JGN.

626. JGN holds efficient levels of insurance cover commensurate with our assessment of business risk. As part of this, we have undertaken a thorough assessment of business risk and aligned our exposure with reasonable and appropriate insurance policies and coverage. We periodically review group insurances in conjunction with

326 See for example, the regulatory proposals of ActewAGL electricity (2015-19 period), the Networks NSW businesses (2015-19 period), and Multinet Gas (2013-17 period).

our insurance broker, taking into account updated underwriting information and applicable operational changes. This review process includes consideration as to whether it is necessary to seek additional coverage, having regard to changes in circumstances.

627. JGN's insurance cap event adopts wording derived from other recent regulatory reviews. For example, our proposed event is substantially the same as that specified in the AER's recent draft decision for Ausgrid[327], with the following minor differences:

- JGN's event does not include a cost materiality qualification in paragraph (c), because in JGN's case the event is subject to a separate cost materiality threshold in clause 3.4 of JGN's AA
- JGN's event refers to the Reference Service rather than the electricity-specific "direct control services"
- we have included a new paragraph (f) in the definition, which simply reflects that in JGN's case insurances are arranged and held at a corporate group level and, should a claim be made in relation to JGN's business, it may be made for JGN by a related party.

628. Paragraph (d) of JGN's proposed insurance cap event definition specifically operates to ensure that incentives for maintaining appropriate insurance cover are maintained right through the next AA period. This paragraph, when read in conjunction with the "relevant policy limit" in paragraphs (b) and (c), operates to ensure that should insurance coverage decrease through the AA period (relative to insurance in place when JGN's AA is approved by the AER), the amount of the decrease will not be relevant for cost pass through purposes.

629. Finally, we note that there is potential for the insurance cap event to overlap with other proposed cost pass through events. Although there could be overlap in some circumstances, JGN is of the view that the insurance cap event (alongside the other events) is reasonable and appropriate on the basis that JGN is potentially exposed to a range of serious damage risks that are typically covered in part by insurance and other mitigations, but where other events such as the natural disaster event or terrorism event will not apply (for example, material network damage arising from a serious train impact, or material damage arising from mine subsidence).

630. Should an event occur that falls within the scope of more than one of these cost pass through events, clause 3.4 of JGN's AA would operate to ensure that there is no "double up" in costs claimed and approved. Specifically, clause 3.4 sets out a process for JGN to seek approval for cost pass through events and in making a determination that an amount should be passed through the AER is able to consider whether the costs of the event have already been factored into the calculation of JGN's annual revenue requirement and any other factors the AER considers are relevant. We note the AER has not raised any issues in its draft decision in relation to this approval process and AER oversight for cost pass through events.

Natural Disaster Event

631. This event captures a key category of uncertain, potentially high cost-impact events that are outside of JGN's control. Natural disaster events include bushfires, earthquakes and extreme weather events – such events typically result in networks businesses incurring substantial costs in undertaking emergency response, repair and rectification activities. Often this work is carried out in a working environment where there are major safety-related risks, together with a clear public imperative to resolve any outages and resume services as soon as possible, resulting in a large-scale operation working within a compressed timeframe.

632. JGN's proposed opex allowance for emergency response provides cover only to the level of emergency response expenditure incurred in the base year. JGN is of the view that the risk of a natural disaster event imposing losses greater than the materiality threshold specified in clause 3.4 of its 2015-20 AA cannot be

[327] See AER, *AER draft decision, Ausgrid distribution determination (2015-16 to 2018-19)*, November 2014, attachment 15.

mitigated by JGN as full coverage via external insurance is cost-prohibitive and, based on recent regulatory precedent, JGN understands that a self-insurance premium will not be approved by the AER.[328]

633. An event of this nature has been approved in a number of recent gas and electricity distribution determinations.[329] In the current AA period, natural disaster-related risks have been mitigated through the broadly-worded business continuity event and general pass through event in JGN's AA (neither of which are proposed for the 2015-20 AA). JGN's proposed wording for the natural disaster event in its 2015-20 AA essentially aligns with the wording adopted in other recent gas and electricity distribution determinations, subject to the following:

- JGN's definition omits the word "major" (as in "major fire,…" etc), as well as the statement that "major" means "serious and significant". This is because cost pass through for such an event is separately subject to the materiality threshold specified in clause 3.4. For similar reasons to those set out above in relation to the deletion of "substantial" in regulatory change event, JGN considers "major" creates unnecessary uncertainty in a mechanism which already applies a financial threshold in excess of $5 million to the relevant event
- JGN's definition also omits the definition requirement that the event must not be caused by the acts and omissions of the Service Provider. This is because that requirement already exists, in the form of the decision making criteria specified in clause 3.4 of the AA which the AER is required to apply in determining whether or not to approve cost pass through.

634. JGN applies mitigation measures with a view to limiting the cost impact of natural disasters through:

- its organisational resilience framework and associated plans. Key policies and frameworks are specified in Table 12–3
- available insurance (both in the case of natural disasters caused and contributed by JGN, and those outside of JGN's control), subject to applicable caps and policy terms.

Table 12–3: Organisational resilience and emergency management policies and frameworks

Policy / Framework	Purpose and scope
Organisational resilience policy	Ensures that there is a systematic, integrated and strategic approach to strengthening our preparedness, timely response, and rapid recovery in the event of a significant business disruption event affecting any of the Jemena Group's critical assets.
Organisational resilience framework	Supports the prioritisation of resilience initiatives and investments to ensure that resources are applied where they offer the most benefit for mitigating risk by lessening vulnerabilities, deterring threats, and minimising the consequences of disruptive events. Within this framework, the key document is the Jemena Business Critical Infrastructure Plan, which defines our critical infrastructure, and sits above a series of plans and procedures dealing with the following: *Proactive components* • physical security framework / infrastructure protection process • site criticality assessments

[328] It is JGN's understanding that the AER will not generally approve a self-insurance premium on the basis that the calculation of the premium is considered to be speculative, both in terms of the probability of loss and impact.

[329] Refer to the current access arrangements of each of APA Gasnet, Envestra (SA), Envestra (Vic) and Multinet.

Policy / Framework	Purpose and scope
	• asset management strategy, policy and plans • asset-specific safety and operating plans (see below) *Reactive components* • security engagement • crisis management plan and emergency management framework (see below)
Crisis management plan	Jemena's Crisis Management Plan describes the Crisis Management Team structure, activation and escalation processes as well as roles and responsibilities during any incident or issue that could have the potential to seriously threaten Jemena's reputation, its operations and/or the safety and well-being of its employees as well as others who may be affected by our actions.
Emergency management framework	This framework allows Jemena business units nominated for emergency roles to manage an emergency through clear and defined objectives when responding pre, during and post an emergency.
Gas emergency management and response plan	Describes the Emergency Management arrangements concerning gas asset-based emergency risks. The plan defines roles and responsibilities for the Emergency and Area Management Teams. The Plan represents Jemena's commitment to its stakeholders, its network and the community to respond to critical emergencies promptly and efficiently.
JGN safety and operating plans	JGN has in place safety and operating plans for: • its distribution network, in respect of which JGN holds a reticulator's authorisation under the *Gas Supply Act 1996*, and • its trunk pipelines that are licensed under the *Pipelines Act 1967* These plans have been developed as part of JGN's commitment to achieving and maintaining full compliance to the standards, pipeline licence and regulations, ensuring that all of its actions and activities do not unduly expose Jemena personnel, contractors or members of the public or the environment to unacceptable risks. To achieve this objective, JGN has completed a risk assessment and developed mitigations and controls to manage the risks. It's Safety and Operating Plan documentation sets out the measures to mitigate these risks, which are to be followed to ensure the reliability and safe operation of our assets. It includes measures to ensure: • the safety of the public • the safety of personnel and contractors working on the network • effective environmental management • effective incident / emergency management.

Terrorism Event

635. As for the proposed natural disaster event, JGN is of the view that the risk of a terrorism event imposing losses greater than the materiality threshold specified in clause 3.4 of its AA cannot be mitigated by JGN as full coverage via external insurance is prohibitive and for reasons noted above a self-insurance premium is not a viable option.

636. We note that an event of this nature has been approved in a number of recent gas and electricity determinations.[330] For the 2010-15 AA period, terrorism-related risks have been mitigated through the broadly-worded business continuity event and general pass through event in JGN's AA (neither of which are proposed for inclusion in JGN's 2015-20 AA). JGN's proposed wording for the terrorism event in its 2015-20 AA essentially aligns with that specified for the terrorism event in the AER's recent draft decision for Ausgrid[331] - except that JGN's terrorism event definition does not include a cost materiality qualification, for the reason that this qualification is separately provided for in clause 3.4 of the AA.

637. JGN has developed a risk assessment framework to proactively mitigate the security risk to its network and non-network assets (see outline in Table 12–3 above). As part of this framework, JGN conducts periodic reviews of its assets every two years, to identify critical infrastructure, determine the security risk at each site and assess the risk of disruption to JGN's operations, should supply issues arise as a result of a terrorist attack. Information received from intelligence services and NSW State Police provide the basis for current threat levels and asset review. Jemena's Infrastructure Protection Process provides guidance on the level of security overlay necessary for a site that is being built, upgraded or altered.

Gas Supply Shortfall Event

638. In our initial proposal we drew the AER's attention to the fact that the risk of a gas supply shortfall is more prevalent in the NSW gas market relative to other parts of southern and eastern Australia.

639. In the 2010-15 AA period, gas supply shortfall risk has been mitigated in part through the business continuity event, which includes reference to gas supply shortfalls. As noted previously, the business continuity event will not form part of JGN's 2015-20 AA. Despite this, the risk of a gas supply shortfall that prompted recognition within the business continuity event remains today, with a number of factors contributing to an environment of gas supply uncertainty – with widespread acknowledgement within the NSW gas sector that there is, and remains, a risk of an upstream supply issue occurring in the 2015-20 AA period, with the potential consequence of there being materially insufficient gas being available for injection into JGN's network. That in turn would require JGN to take steps to safely manage the impacts, as described further below.

640. Recent examples of commentary on potential gas supply risks for NSW are highlighted in Table 12-4.

Table 12–4: Gas Supply Shortfall commentary and analysis

Source material	Content
AEMO, *Gas Statement of Opportunities for Eastern and South-Eastern Australia 2013*	• If production in Queensland and South Australia is prioritised for export, there will be flow-on effects to New South Wales with potential shortfalls of 50-100 TJ/day over winter peak demand days from 2018 • Committed and advanced projects in New South Wales are not sufficient to completely alleviate these shortfalls without further support from the Moomba-Sydney Pipeline
Simshauser, Nelson, *Solving for 'x' – the New South Wales Gas Supply Cliff,* Working Paper No 40, February 2014	• NSW is the region most vulnerable to a large demand shock because it is almost completely reliant on interstate gas supplies to satisfy local demand • Under conditions of a supply crisis… State Energy Ministers can direct the use of on-shore gas inside their jurisdiction, and this can extend to directions to stop interstate exports. This is crucial to NSW's supply situation.
AEMO, *Gas Statement of*	• There is potential for gas supply shortfalls to occur in NSW towards 2020

[330] Refer to the current access arrangements for each of APA Gasnet, Envestra (SA), Envestra (Vic) and Multinet.

[331] Refer to AER, *AER draft decision, Ausgrid distribution determination (2015-16 to 2018-19)*, November 2014, attachment 15.

Source material	Content
Opportunities Update (May 2014)	• NSW will be dependent on a proposed 100 TJ/day development at Narrabri to ensure shortfall risks at that time do not increase
Department of Industry (Commonwealth Government), *Energy Green Paper* (September 2014)	• Without timely investment in natural gas infrastructure and the development of reserves, there will be potential gas shortfalls in New South Wales across four winter days in 2020
Sydney Morning Herald (9 January 2015)	• NSW faces three weeks' worth of gas shortages in winter next year and the state government may have to invoke emergency powers to ration gas supplies
K Lowe Consulting, *Gas Market Scoping Study: A report for the AEMC* (July 2013)	• The critical question currently facing the eastern Australian gas market is whether domestic oriented production will be able to expand rapidly enough to ensure that there is sufficient gas available in the domestic market over the period 2015-18, which is when a large number of domestic contracts expire, and LNG projects will be ramping up to full capacity • While it is possible that production from existing sources in eastern Australia could increase, the gap that will be left as a result of the LNG developments is such that new sources of supply will need to come on line in this period • The difficulty that the market currently faces is that only one of the proposed developments has passed the final investment stage. It is unclear therefore at this stage whether the remaining developments will proceed and, if so, the extent to which they will be used to supply the domestic market • The other key uncertainty currently facing the market is whether those projects that pass the final investment decision stage will be able to be brought on rapidly enough to fill the gap in the domestic market that is expected to emerge from 2015

641. It is clear from the above that there are various views at present as to the magnitude of supply shortfall risks, with interlinked factors including the LNG export market and the development of CSG projects within NSW.

642. This is very much a gas-specific issue and a NSW-specific issue, where NSW is a comparative disadvantage to other, gas-producing States, with available gas in a shortfall scenario likely to be prioritised for supply within the State in which it originates.

643. Given the gas and NSW-specific circumstances, JGN cannot draw upon recent regulatory precedent to provide support for this event and considers that harmonisation with the NER and electricity determinations is not appropriate in this instance. Nevertheless we note that gas supply shortfall has been an integral part of the business continuity event in JGN's current AA and, in addition, ActewAGL Distribution's current AA includes a "Supply Curtailment Event", which was designed to operate in very similar circumstances to JGN's proposed gas supply shortfall event.

644. In any case, JGN considers that the gas supply shortfall event it is proposing satisfies the criteria that the AER typically considers in deciding on the appropriateness of cost pass through events. As with the other events outlined in this section, it is difficult to predict when and how such a gas supply shortfall event might occur, but:

- JGN has virtually no ability to prevent or mitigate the impacts of such an event on its network, given that it would originate well upstream (i.e. the event is uncontrollable, and JGN acting prudently could not have reasonably prevented the event from occurring or substantially mitigated its cost impact)
- the potential consequences on both JGN and its customers could be material.

645. In summary, the consequences of an upstream gas supply issue would be as follows:

- if insufficient gas is made available for injection into JGN's network, then as demand starts to outstrip supply the shortfall in supply is drawn from the static inventory of pressurised pipelines, and as a result the pressure of gas being supplied to the network will fall. If no action is taken to supplement supply or to reduce demand, the pressure of gas received by JGN will continue to drop until it falls below the minimum operating pressure needed to maintain normal network operations
- in that circumstance, the network's capacity to transport gas through the network and the ability to maintain safe minimum operating pressures within the network will be materially adversely affected. Gas supply available to customers will weaken and progressively fail as sections of the network become de-pressurised
- practically what happens—if JGN perceives an upstream issue to create a supply risk—is that JGN will take pre-emptive action to maintain pressure where possible, commencing with:
  - consultation with market participants and upstream transmission pipelines to understand the timing and risks for transmission system supply reliability
  - communication with network users (and AEMO if a network section downstream of the Sydney STTM hub is at risk) to promote all possible commercial actions being taken by the gas market to avoid a supply imbalance occurring in the network (either by securing additional supply or reducing demand – either by participants or through market processes such as STTM contingency gas). Communications would also include government briefings
  - if the operational outlook is still that minimum network operating conditions will not be met then, if time permits, JGN will take steps to reduce demand to avoid or slow down the impact of the event through the network load shedding (which prioritises significant customers, based on a load shedding order of priority outlined in JGN's RSA and AA)
  - if the operational outlook is that supply will be lost within the network then JGN will introduce emergency operational procedures to actively manage the shut-down of the network and sections of the network will be actively shut down entirely to manage safety risks across the network
- given the safety issues that flow from a loss of positive gas pressure in the network and the time required to achieve physical load reductions through load shedding (>24 hours) and to mobilise large scale emergency responses, JGN would potentially need to act quickly to take preventative measures to manage the issue, well before a significant pressure drop is experienced within the network (that is, in keeping with its statutory obligation to operate a safe and reliable network, JGN cannot delay action until the pressure drop impacts have fully materialised in the network—rather, action may need to be taken where there is a threat of a material issue, for example based on information JGN receives from upstream parties)
- as outlined in JGN's RSA, JGN usually has some discretion as regards commencement and implementation of load shedding and suspension of services to manage operational risks on the network—however if the upstream supply issue is significant and requires a longer term approach to mitigating the impact on customers (JGN's considerations are principally about an immediate operational response to a supply threat), it is possible that the NSW Government might intervene, exercising emergency powers set out in the *Energy and Utilities Administration Act 1987* (NSW) to direct / ration available supply to some customers over others
- in the event that all or part of the network is shut down due to lack of supply, there will be significant disruption for those impacted. Even if the upstream supply issue is resolved relatively quickly after such a shut-down, supply within the network could be impacted for days and possibly weeks[332]

[332] This is quite different to electricity networks where power in the network can simply be "switched on" again. Once supply is lost in a gas network, customer supply cannot be simply switched on again as soon as upstream supply is made available.

- these supply interruptions arise due to the need, for safety reasons, for network infrastructure to be purged of the remaining gas / air mixture, before gas can be reintroduced, and appliances re-lit at each site. When positive gas pressure is lost in any section of the network, a critical, high risk safety issue arises, as it then becomes possible for air to enter gas mains and form a combustible air-gas mixture within the pipes[333], and an extensive emergency operational response is required to safely shut down and then recommission gas mains before reconnecting and reinstating supply to each individual customer in any section of the network which has or may have lost positive pressure

- JGN's experience from minor supply outages is that the purge / supply / relight process is highly labour intensive, and even in the case where a suburb or a small town is impacted, the process may take several days. If the whole or a significant part of the network is impacted, some customers could be without gas for weeks.

646. Set out below is an extract from JGN's field manual, which explains the process that would apply in the case of a supply outage arising from a gas shortfall event, which would involve JGN's gas service technicians walking the streets of impacted areas of Sydney, Wollongong, Newcastle and country centres to re-initiate supply:

> *Recommissioning shall not commence until a full "make safe" process has been completed for all affected end-users. To make safe, turn off all meter control valves (MCV), boundary regulators, path valves or disconnect inlet services.*
>
> *Before recommissioning supply, personnel are required to advise and obtain clearance from the Emergency Controller.*
>
> *On completion of all work, all mains and services shall be purged… Where possible, all appliances shall be purged, re-lit and checked.*
>
> - *No service shall be recommissioned until it has been tested and confirmed as sound*
> - *If the end-user is not home when supply is restored, leave the MCV turned off, and leave written instructions on "how to relight" in clear view for the end-user*
> - *If the consumer piping has been physically disconnected, then test as per Chapter 16 Testing, Pressure Testing of Services, prior to restoring supply.*
> - *Relight appliances. Do not attempt to relight an appliance if you do not understand its operation*

647. Other than cost pass through, there are several other potential risk mitigations available to JGN where there is a gas supply shortfall issue:

- first, JGN maintains an ongoing dialogue with producers, pipeline operators and wholesale gas market participants, and also encourages network users to maintain a similar dialogue. Information received via these communication channels enables JGN to better understand upstream conditions and issues (noting that as between JGN and its network users, it is the network users who have the contractual relationships with upstream parties, and are therefore best placed to source information, and influence upstream conditions to minimise downstream risk)

[333] Natural gas will only combust when mixed with air in the combustible range of 5-15%. This is a key safety characteristic of natural gas as a fuel and means that gas within the network (100% natural gas within the pipes) cannot be ignited or cause an explosion until the gas exits the pipes and is mixed with air.

- second, JGN has the benefit of various provisions in its reference service agreements with individual network users in which, as between JGN and each user, the user bears contractual responsibility for upstream issues, including providing indemnities in certain circumstances. [c-i-c]

  Although network users are better placed than JGN to bear contractual risk in this area, they must still rely on a contractual chain of responsibility flowing from the network users to wholesale market participants, to pipeline operators and gas producers. If there is a gas supply shortfall, in some cases it may be possible to manage JGN's exposure contractually, but this is not the case for all shortfall scenarios

- third, JGN's insurance may potentially be available to cover some financial exposure in the event of a gas supply shortfall, however this will depend on the nature and magnitude of the event, as well as the particular categories of loss involved. JGN understands that in some scenarios, insurance may be available (subject to relevant caps and conditions) but in other cases mitigation via insurance is not available at all. For example in the case where JGN takes pre-emptive action to shut down parts of the network to avoid major safety-related issues, but where there is no physical damage to the network, its costs of responding to such an incident, together with its loss of revenue, would not be covered by current insurance.

648. If a gas supply shortfall event occurs, and JGN seeks cost pass through, it would still need to satisfy the AER about the efficiency of its decisions and actions in relation to the event (including in relation to its prudency in relation to the above potential risk mitigations), as provided in clause 3.4 of its 2015-20 AA. Furthermore, the financial materiality threshold would also need to be met. Given the environment of uncertainty that currently surrounds gas supplies into NSW, and the potential for significant cost exposure should a shortfall materialise, JGN submits that it is reasonable and appropriate for this event to be included in its 2015-20 AA.

Insurer Credit Risk Event

649. Although the likelihood of risks materialising that are associated with the insolvency of an insurer of JGN's business is very low, it has happened in the recent past, and therefore is something a prudent service provider should take into account in setting the scope of cost pass through under an AA. Potential cost impacts, if this risk does crystallise, would include:

- the cost of replacement insurance (which could be significantly greater, depending on the insurance market at the time, and also whether the insurance is arranged on an urgent basis)
- potential cost impacts arising from differing claim limits and deductibles under any replacement insurance
- in the event that self-insurance is pursued, the cost of funding self-insurance.

650. We note that an event of this nature has been approved in a number of recent gas and electricity determinations.[334] In JGN's case, the cost materiality threshold is proposed for inclusion in the definition itself by reference to materiality threshold wording which we have extracted from clause 3.4 of JGN's 2015-20 AA.

651. The SGSPAA Group takes a number of precautions to mitigate JGN's exposure to an insurer's credit risk event including:

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[334] See, for example, the access arrangements of the following gas distribution businesses APA GasNet (2013-17), Envestra (SA) (2011-16), Envestra (Vic) (2013-17) and Multinet (2013-17).

- the appointment of a global insurance broker with the ability and the resources to place the SGSPAA Group insurance program and to also regularly monitor and report to us on the credit risk of all insurers
- the inclusion of conditions in our contract with our broker that all insurers we deal with should be rated Standard & Poor's (or equivalent ratings agency) A- or better
- the receipt of quarterly insurer security rating reports from our broker in relation to credit rating and reputation
- the diversification of the insurance portfolio, particularly the larger insurance policies (general liability and industrial special risks (property insurance))

652. Despite the above, there remains an ongoing risk that an insurer may still fail. If it does, JGN could face considerable exposure, in circumstances that would be well beyond its ability to control. To ensure that JGN has the opportunity to recover at least its efficient costs, JGN is proposing an insurer credit risk event.

653. In the context of this event, JGN notes that:

- clause 3.4 of its 2015-20 AA requires the AER to take into account, in making a determination on whether or not to allow cost pass through, the efficiency of JGN's decisions and actions in relation to the risk. This would include examining whether JGN, at the time of taking out or renewing the relevant policy with the insolvent insurer, took reasonable steps to assess the financial viability of the insurer including whether the insurer had the capacity to satisfy claims under the policy
- an event of this nature has been approved by the AER in recent gas networks access arrangements for APA GasNet, Multinet Gas, Envestra (SA) and Envestra (Vic).

654. We further note that the AER draft decision for the Networks NSW businesses and ActewAGL electricity distribution has proposed the rejection of this event. The AER cites the following two reasons for this[335]:

> *…because a prudent service provider could reasonably prevent an event of that nature from occurring*
>
> and
>
> *…we may encourage NSPs to obtain insurance from providers who are not capable of paying large claims or to not monitor or review the viability of their insurance provider.*

655. JGN considers that both these reasons are not based on sound rationale.

656. First, as mentioned above, the circumstances that lead to this type of event occurring will generally be well outside a service provider's control, and a prudent service provider cannot always anticipate the failure of an insurance provider. The AER needs only to consider the cause and impact of the HIH Insurance collapse in 2001 and AIG Insurance's difficulties during the Global Financial Crisis in 2009. Both these companies were widely considered to be strong and reputable insurance companies prior to the difficulties they experienced.

657. On the second reason, it is simply unacceptable and would be non-compliant with corporate policy and governance requirements for JGN to take out insurance with an insurer it knew to be of questionable viability. The SGSPAA Group takes a number of precautions to mitigate JGN's exposure to an insurer's credit risk event including (as noted above):

[335] AER, Ausgrid draft decision 2015-16 to 2018-19, November 2014, pp15-13 to 15-14.

- the appointment of a global insurance broker with the ability and the resources to place the SGSPAA Group insurance program and to also monitor the credit risk of all insurers
- the inclusion of conditions in our contract with our broker that all insurers we deal with should be rated Standard & Poor's (or equivalent agency) A- or better
- the receipt of quarterly insurer security rating reports from our broker in relation to credit rating and reputation
- the diversification of the insurance portfolio, particularly the larger insurance policies (general liability and industrial special risks (property insurance))

658. We believe there are strong checks and balances in place—both internally as a matter of proper corporate governance, and through the AA provisions—to remove any incentives for us to act inappropriately in reliance on the insurer's credit risk pass through event.

12.2.1.4 Network user failure event

659. JGN has considered the AER's position in relation to this event, together with matters including:

- recent regulatory precedent (cost pass through events of this nature have been previously approved by the AER in Victoria (gas and electricity) and SA (gas), in addition to the network user failure event that was approved by the AER in JGN's 2010-15 AA)
- the retailer of last resort (**RoLR**) event definition in the National Energy Retail Law (**NERL**)
- the scope of s167 of the NERL and rule 531 of the NGR, which operate together to provide partial relief to distributors in certain circumstances of retailer failure. In this regard, s167 only deals with the reimbursement of costs paid to the RoLR by the distributor (as a mechanism to give effect to recovery of the RoLR's costs, not the distributor's) and rule 531 only provides for the recovery of the distributor's costs where the retailer defaults on payment of its distribution charges, but otherwise would not be triggered by the declaration of a RoLR event. Hence these rules provide partial treatment in certain instances of retailer insolvency (but not in the case of any other category of RoLR event)
- a recent change to the NER proposed by the COAG Energy Council, which is currently being evaluated by the AEMC, which is intended to correct an error in amending the NER to implement the NECF. The effect of the rule change is to clarify that the NER-equivalent of rule 531 of the NGR enables electricity distributors to recover revenues foregone from retailer insolvency (i.e. amounts that the distributor would have billed but not recovered due to the retailer becoming insolvent, and the distributor incurs costs that it would not have incurred in the normal course of events). In addition, the rule change before the AEMC provides that the NER retailer insolvency event is not subject to the one per cent annual smoothed revenue materiality threshold in the NER.

660. Having undertaken this further assessment, JGN maintains the position in its initial proposal in relation to the network user failure event. JGN also proposes that, consistent with the recent change to the NER proposed by the COAG Energy Council (which is being made to reflect the policy intent of NECF) the network user failure event should be revised:

- to make it clear that it extends to the recovery of revenue foregone due to retailer insolvency, in addition to the cost impacts arising from a RoLR event and have adopted similar wording as proposed by the COAG Energy Council (we consider that the definition as drafted in our initial proposal could be interpreted to enable JGN to recover this revenue, but that to ensure clarity and for ease of understanding, the wording could be improved in light of this rule change proposal)

- so that the event is not subject to the materiality threshold in clause 3.4(b)(i) of the AA. This is also consistent with the cost recovery mechanism in rule 531 which – although requiring robust supporting evidence to be presented to the AER to justify an application for cost pass through – is not subject to a financial materiality threshold.

Network user failure event – key issues:

- Event scope should not be limited to retailer insolvency – RoLR event coverage is broader
- Event wording must clearly extend to recovery of JGN's revenue foregone due to retailer insolvency
- Event should not be subject to financial materiality threshold.

661. As JGN has advised previously[336], its network user failure event is intended to cover the cost impacts that arise as a result of the significant administrative and logistical tasks that JGN is required to perform under NSW/ACT Retail Market Procedures to support the transfer of customers in retail market systems from one retailer to another – in a sudden and non-standard manner. Whilst retailer insolvency is an obvious example of when this might be required, it may also be relevant in various other circumstances, as highlighted in the definition of "RoLR event" in the NERL, which extends to cover the following (in addition to retailer insolvency):

- the revocation of a retailer's retailer authorisation (e.g. where a regulator revokes this authorisation as a consequence of one or more material breaches of licence conditions, which are unrelated to solvency, or pursuant to NERL s107(2)b), which provides for revocation of retailer authorisation where it is apprehended that a retailer will not be able to meet its statutory obligations in the future)

- the right of the retailer to acquire gas in either the declared wholesale gas market or the STTM is suspended (once again, this is possible in a non-insolvency context, where market rules or procedures are breached – for example the various default events under rule 486 of the NGR can result in suspension of a network user's right to acquire gas from the STTM under rule 488, which in many cases does not require the retailer to be insolvent (e.g. a retailer may be solvent but has not maintained AEMO's required level of security))

- where there is no declared wholesale gas market or STTM, the retailer's registration as a registered participant in a retail gas market is revoked

- the retailer ceases to sell energy to customers, other than by transferring or surrendering its retailer authorisation in accordance with the NERL, or as a consequence of transferring some or all of its customers to another retailer, or by selling its business of the sale of energy to another retailer.

662. In any scenario leading to a RoLR event (irrespective of whether or not it involves insolvency of a retailer) which then leads to AEMO applying the RoLR procedures in the NSW/ACT Retail Market Procedures, JGN will be required to perform its obligations under those roles to facilitate the transfer of customers in retail market systems.

663. Where a RoLR event occurs and the AER appoints a RoLR in the NSW gas retail market, obligations under the NSW/ACT Retail Market Procedures are triggered, including:

- to provide AEMO with an estimate meter reading for every customer being transferred

[336] See JGN's response "Pass through events – information request 26", 12 September 2014, p 2-3.

- to work with AEMO and the designated RoLR to settle an outcome for each outstanding service order transaction that is “open” (e.g. customer churns, new connection requests, disconnection requests)
- to work with AEMO and the designated RoLR to complete a reconciliation, where deemed necessary by AEMO no later than 65 days after the transfer.

664. JGN has very limited system automation for this process (given the low probability of a RoLR event occurring) and therefore all of these transactions would be required to be completed manually.

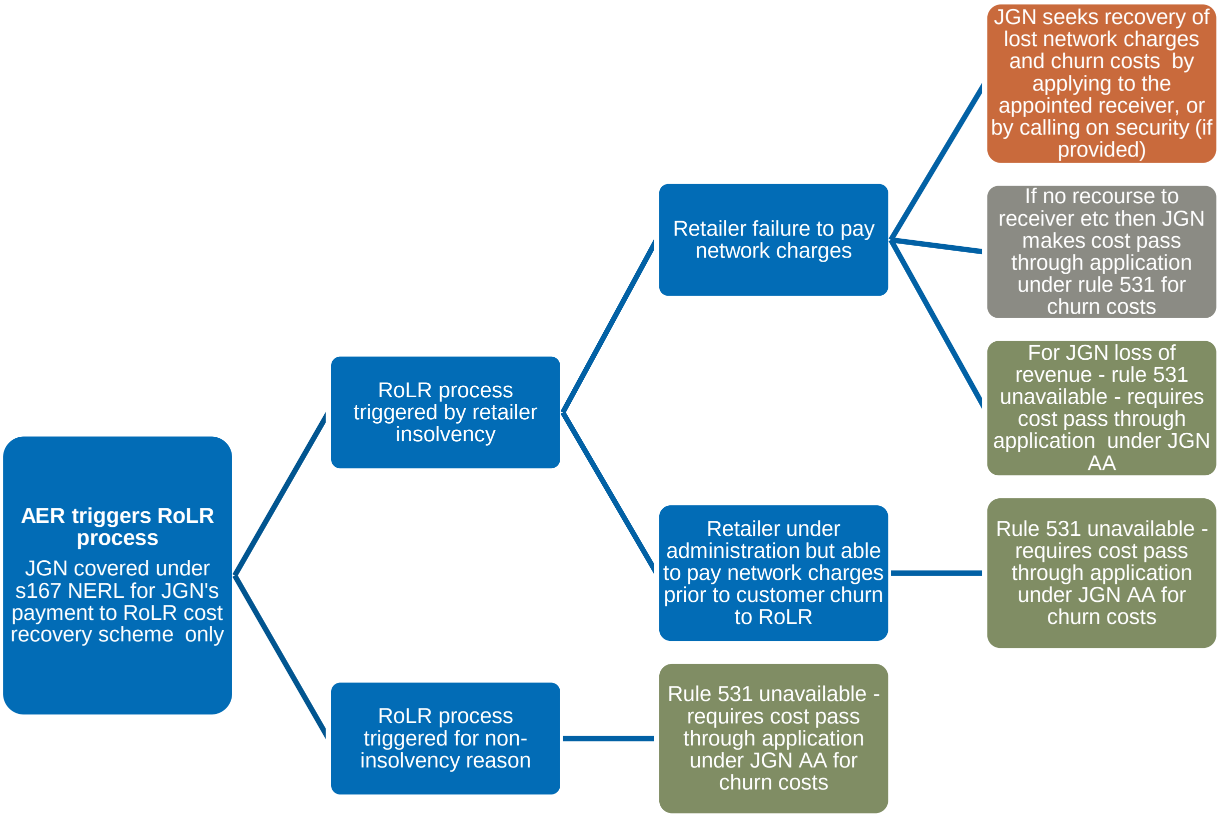
665. JGN’s costs would be dependent on the particular circumstances, including the scale of the transfer. In particular, the AER’s ability to choose the RoLR (and potentially multiple RoLRs for one event) could result in JGN incurring greater costs – for example if customers are spread amongst several RoLRs, rather than just one.

666. In addition to the above actions, a RoLR event would result in JGN incurring further costs (e.g. additional resourcing) for making manual changes to delivery point identifiers in our billing systems and making changes to accounts receivable.

667. Should such an event occur in circumstances which are unconnected to retailer insolvency (as defined in rule 531(4) of the NGR), JGN would have very limited ability to mitigate its cost exposure. In this regard, JGN notes that the network user failure event addresses matters that JGN cannot predict, which are entirely outside of its control, and in a RoLR event context (other than in the case of retailer insolvency, where the NECF laws potentially apply), absent cost pass through, JGN is unable to seek cost recovery from the retailer or retailers concerned, or indeed any other participants in the market.

668. Figure 12–1 below illustrates JGN’s potential options for cost recovery in the event of a RoLR event occurring. There is reasonable – but not full – coverage in the event of retailer insolvency, but for other RoLR events JGN must rely on the network user failure event for recovery of its costs in handling the bulk churn of customers from the failed retailer to one or more RoLRs.

Figure 12–1: RoLR event cost pass through scenarios



669. JGN has acted efficiently to avoid the cost of a project to change JGN's systems to automate the RoLR customer transfer process, because we consider that the low probability of occurrence does not justify the significant cost of doing so. Recognising this, the AER approved the network user failure event in the 2010-2015 AA. Since then, NECF-related changes to the law and rules have reduced the range of circumstances in which cost pass through is needed – however, as noted above those changes only extend to circumstances of retailer insolvency, and not to other RoLR categories, and therefore the need for the network user failure event remains.

670. As a result, JGN proposes the following revised definition of network user failure event for inclusion in the 2015-20 AA:

> ***Network User Failure Event*** *means the occurrence of an event whereby a User becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another User, but excludes costs that could be the subject of a pass through amount pursuant to rule 531 of the National Gas Rules or section 167 of the National Energy Retail Law.*
>
> *For the purposes of this event the Service Provider may seek to pass through amounts that the Service Provider is entitled to be paid (but which are or will be unpaid as a result of a Network User Failure Event) for the provision of the Reference Service, including the revenue impact the Service Provider sustains or will sustain as a result of those unpaid amounts. For the avoidance of doubt, references to incurring "costs" in clause 3.4 include these amounts.*

671. Furthermore, clause 3.4(b) of JGN's 2015-20 AA is proposed to be amended as follows:

> *The Service Provider may seek the approval of the AER to pass through costs where:*
>
> *(i) as a result of a Cost Pass Through Event (other than a ~~Regulatory Change Event that relates to carbon~~ Network User Failure Event), the Service Provider has incurred, or is likely to incur, higher costs in providing the Reference Service than it would have incurred but for that event and those costs are or are reasonably estimated to be:*
>
> *(A) in total over the 2015-20...*
>
> *(B) in at least one…*
>
> *(ii) as a result of a ~~Regulatory Change Event that relates to carbon~~ Network User Failure Event, the Service Provider has incurred or is likely to incur higher costs in providing the Reference Service…*

672. For any network user failure event JGN would still need to satisfy the AER as to the various factors listed in clause 3.4(j) of its 2015-20 AA, including the efficiency of its decisions and actions in relation to the risk of the event (i.e. notwithstanding the lack of a materiality threshold, there are sufficient checks in place to ensure that cost pass through will only occur when it is reasonable and appropriate).

12.2.2 MATERIALITY THRESHOLD

673. The AER's assessment of our materiality threshold proposal is consistent with recent decisions. However, we feel that the draft decision has not engaged with the substance of the positions JGN has put forward in our initial proposal. We believe our proposal was a clear, logical and preferable alternative view on pass through materiality thresholds that are demonstrated to remove inappropriate incentives from the regulatory regime and are justified as being in customers' best interests.

674. In principle, JGN accepts the application of a materiality threshold to pass through events within the context of providing JGN with a reasonable opportunity to recover its efficient costs and promoting efficient investment in the network. However, JGN considers that the current threshold (as set out in the AER's draft decision) will not in every case provide JGN with a reasonable opportunity to recover its efficient costs, and can in some cases create incongruous outcomes.

675. The draft decision did not address the comprehensive reasoning we put forward in our initial proposal for an alternative materiality threshold, so we repeat it here for the AER's consideration.

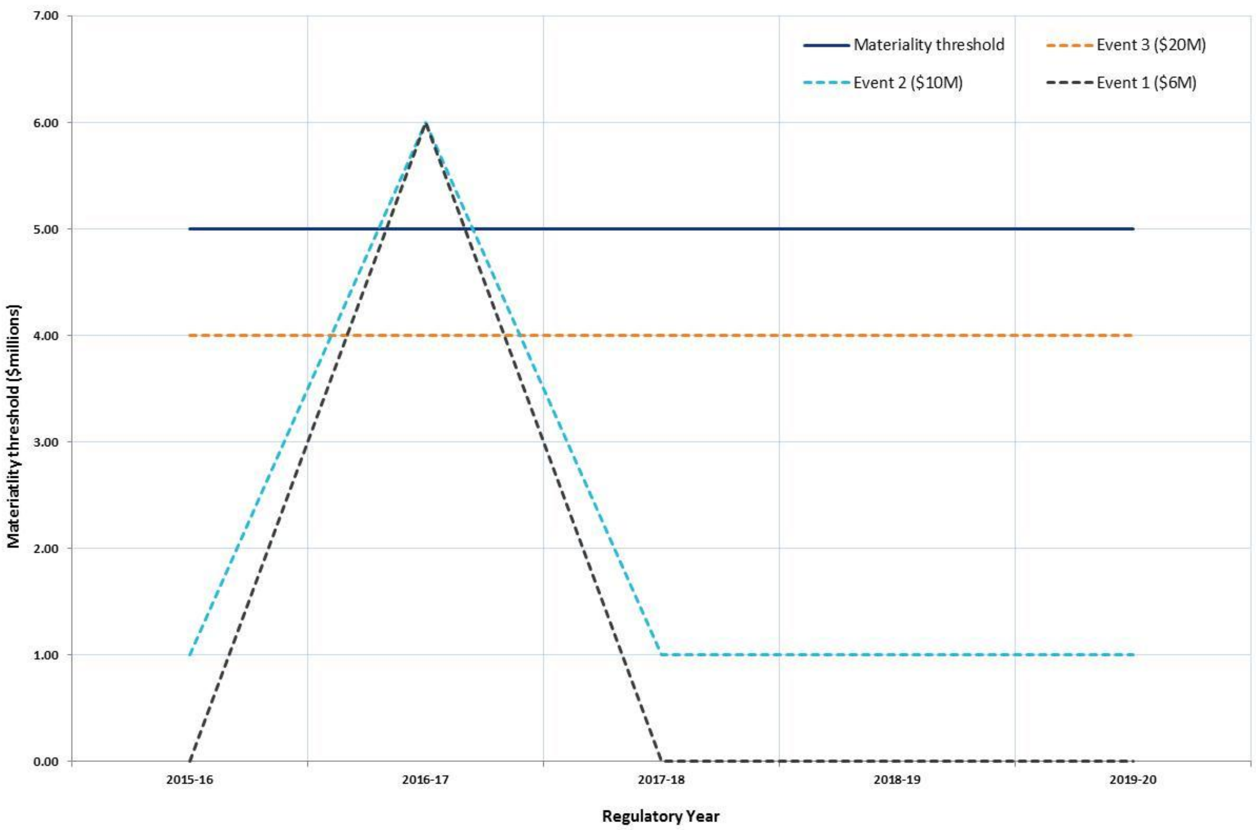
12.2.2.1 Problems with the current threshold

676. Consider Figure 12–2, where annual smoothed revenues are assumed to be \$500M and so a one per cent threshold is \$5M p.a. and the following circumstances arise:

- event 1 occurs in the second year of the regulatory period (2016-17), and will impose a one-off incremental cost of \$6M. JGN can submit a pass through application for this event because in the year of the period that costs are incurred (i.e. 2016-17) the \$5M materiality threshold is met. This outcome is appropriate given the material impact on JGN's costs and cash flows as a result of the event.

- event 2 occurs in the first year of the regulatory period (2015-16), and will impose an annual incremental cost of $1M except in 2016-17 where it imposes a cost of $6M (total cost of $10M). A possible interpretation of the provisions in the 2010 AA could result in a situation where JGN is unable to submit a pass through application for this event in respect of the costs incurred in years 2015-16, 2017-18, 2018-19 and 2019-20, because in these years of the period that costs are incurred (i.e. every year except 2016-17) the materiality threshold (being at least one per cent of the smoothed revenue requirement specified in the final decision in the years of the AA period that the costs are incurred) is not met. In JGN's view such an outcome would be inappropriate when looked at in light of the overall materiality of the total cost of the event. Such a structure would also provide an incentive to a service provider to inefficiently shift costs and/or overinflate cost forecasts for those four years to meet the materiality threshold if it was held that the threshold had to be reached in respect of each year in which the costs are incurred.
- event 3 occurs in the first year of the regulatory period (2015-16), and will impose an annual incremental cost of $4M (total cost of $20M). Again, one possible interpretation of the provisions in the current AA could result in a situation where JGN is unable to submit a pass through application for this event at all, because in every year of the period that costs are incurred the materiality threshold is not met. In JGN's view this outcome is also inappropriate because of the materiality of the total cost of the event ($20M). Such a structure would also provide a service provider with an incentive to overinflate cost forecasts to meet the materiality threshold (and be inconsistent with the intention of the Efficiency Benefit Sharing Scheme (**EBSS**)) and/or inefficiently shift costs that could be incurred over multiple years to a single year to meet the relevant threshold, potentially leading to unnecessary price spikes for customers.

Figure 12–2: Materiality threshold application



677. To the extent the existing threshold was applied such that costs could only be passed through where they were at least equal to one per cent of smoothed revenue in each of the years in which they were incurred, the outcomes from events 2 and 3:

- do not recognise the fixed cost nature of proposing and assessing pass through applications
- are inconsistent with the revenue and pricing principles and the NGO and encourage inefficient cost shifting
- result in potentially incongruous outcomes (e.g. if the event caused JGN to incur $6M in one year only, this $6M could be passed through, but $20M incurred over 5 years could not).

12.2.2.2 Problems with the AER's logic

678. The draft decision favours the current one per cent threshold because:

1. it will only allow a business to recover costs incurred that are significant in any given year, reducing the incentives on service providers to operate their businesses efficiently and minimise unexpected costs
2. this resembles a cost of service regulation, which would not be consistent with the incentive regulation regime
3. it minimises administrative costs associated with assessing pass through applications.[337]

679. We have concerns with each of these three points:

1. On the first point, the one per cent threshold may not allow a business to recover costs incurred that are significant in any given year because the threshold, based on the draft decision wording, applies to costs in <u>each</u> year that costs are incurred:

   > *The Service Provider may seek the approval of the AER to pass through costs where as a result of a Cost Pass Through Event the Service Provider has incurred, or is likely to incur, higher costs in providing the Reference Service than it would have incurred but for that event and* ***those costs are at least one per cent of the smoothed revenue requirement specified in the final decision in <u>the years</u> of the access arrangement period that the costs are incurred****.*

   a) for example, consider a pass through event that causes $4M to be incurred in year 1, and $6M to be incurred in year 2, where the pass through threshold is ~$5M

   b) the draft decision threshold is potentially ambiguous—the above wording could be read as meaning recovery is permitted as a result of the event for only one of the years in which costs are incurred (i.e. year 2, where the incurred costs ($6M) are above the pass through threshold ($5M)).

   Further, the one per cent threshold does, in fact, reduce incentives to minimise unexpected costs because knowing that we must meet an unreasonably high threshold incentivises us to consider options to inefficiently incur sufficient costs in each year to ensure we are kept whole from the impact of the uncontrollable event (as explained in the example above)

   The AER's logic may apply to events with impacts well-below a one per cent threshold, however it should be noted that we are not proposing that no materiality threshold apply to pass through events—we are simply proposing a more reasonable threshold, that is sufficiently material, in the context of JGN's business, that it would still exclude low impact events.

2. On the second point, the one per cent threshold is not inconsistent with incentive regulation because:

[337] AER, *JGN 2015-20 access arrangement draft decision*, 27 November 2014, section 11.4.5

a) by definition, pass through events are outside the control of the business and the cost impacts are often significantly (or completely) outside its control, so the disciplines created by incentive regulation are lessened.

   i) This is reflected in the AER's own EBSS guideline excluding such events from the application of that incentive mechanism

b) the AER has full power under the AA to disallow efficient and imprudent costs incurred as a result of the event, which is consistent with an incentive regulation framework and completely inconsistent with cost of service regulation.

c) The NGO is clearly best supported by a properly specified pass through materiality threshold that allows policy and rule makers and market operators to make refinements to the regulatory and market regimes at any time. The incentive effects of unduly constraining event costs to any one year (as opposed to the remaining duration of the AA period) will motivate JGN to seek to delay regulatory change events until the subsequent regulatory period in order to ensure cost recovery. A consequence of the AER's draft decision and our NECF experience is that JGN would face a strong incentive to lobby for these reforms to be delayed until the 2020-25 AA period. Such an incentive would be at odds with the NGO.

3. On the third point, minimising administrative costs is the wrong test:

   a) the right test also takes into account the allocative inefficiency created by a business incurring material costs that are outside its control, which is likely to be significantly higher than the administrative costs of assessing pass through events. Allocative inefficiency does not promote the NGO because it stifles efficient investment in the network and does not provide the business a reasonable opportunity to recover its efficient costs (recognising that JGN is not proposing no materiality threshold apply)

   b) further, administrative costs for assessing pass throughs under the AA are minimised because they would likely be considered at the same time as the TVN is considered, recognising that the AA has a range of no-threshold annual adjustments administered through the TVN.

680. JGN's firm position on this matter is supported by the case study set out in Box 13–1.

Box 13–1 Case study – material NECF costs falling below AER materiality threshold

JGN has spent a considerable amount in order to achieve compliance with the NECF laws and rules, but for various reasons this amount has been spread over a period from 2011-12 to date, and at this point appears likely to extend through 2014-15 into 2015-16, with further systems changes to be implemented in conjunction with B2B harmonisation in April 2016 in order for JGN to move from "transitional phase" NECF to comply with "full" NECF, which commences for JGN on 1 July 2015.

This issue was noted in JGN's annual RIN response for 2012-13, as follows:

> *In addition to the cost pass through events detailed in Table 3, JGN incurred costs associated with the implementation of the transitional National Energy Consumer Framework (NECF) arrangements. These costs were incurred across several regulatory years.*
>
> *The NECF costs JGN incurred were related directly to new laws coming into force which required JGN to make significant changes to aspects of its network operations. As such, this would constitute a Market Costs Event under JGN's AA if the costs incurred are substantial enough in any one regulatory year to meet the one per cent smoothed revenue threshold. In the case of NECF, the costs (excluding internal labour) JGN incurred due to this event amounted to* [c-i-c] *during the 2011-12 regulatory year and a total of* [c-i-c] *over the life of the project. However, in no single year did JGN's NECF implementation costs exceed the one per cent of smoothed revenue threshold.*

That is, as at 30 June 2013, JGN had incurred cost of [c-i-c] in relation to NECF-related changes to its business, well in excess of the one per cent smoothed revenue threshold for the 2012-13 regulatory year ($4.24M). But as JGN noted at the time, cost pass through was not available because the costs were spread over several years. The main reason for this was well outside the control of JGN – in June 2012, slightly less than one month before the implementation date for the transitional NECF laws and rules in NSW, the NSW State Government unilaterally deferred NECF implementation indefinitely. This resulted in further costs being incurred on a "stabilisation" phase to preserve the value of the considerable work completed up to that point in time. The NSW Government revived NECF implementation in early 2013, which resulted in JGN carrying out a "re-mobilisation" phase, leading to implementation of transitional NECF on 1 July 2013.

Further costs are now being incurred in relation to NECF implementation, as JGN moves from transitional NECF to full NECF compliance from 1 July 2015, with final systems changes to be implemented at the same time as the B2B harmonisation project in April 2016. This phase of the project includes project management resources, system design, legal and compliance and IT system build. Taking into account work done since June 2013, and that the project will not complete until 2016, it is foreseeable that NECF implementation over the period from 2011 to 2016 could result in an aggregate spend in the vicinity of 0.5 per cent smoothed revenue for a five year AA period (though noting that in the case of NECF it has occurred over two AA periods), even though in no single year has the one per cent smoothed annual revenue threshold been met.

12.3 REVISED PROPOSAL

12.3.1 PASS THROUGH EVENTS

681. JGN proposes the pass through events set out in Table 12–1:

Table 12–1: Proposed pass through events

Event name	Event specification
Regulatory change event	***Regulatory Change Event*** *means a change in a regulatory obligation or requirement that falls within no other category of Cost Pass Through Event and affects the manner in which the Service Provider provides the Reference Service;*
Service standard event	***Service Standard Event*** *means a legislative or administrative act or decision that has the effect of:* *(a) Varying, during the course of an Access Arrangement Period, the manner in which the Service Provider is required to provide the Reference Service; or* *(b) Imposing, removing or varying, during the course of an Access Arrangement Period, minimum service standards applicable to the Reference Service; or* *(c) Altering, during the course of an Access Arrangement Period, the nature or scope of the Reference Service, provided by the Service Provider.*
Insurance cap event	***Insurance Cap Event*** *means an event where:* *(a) the Service Provider makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;* *(b) the Service Provider incurs costs beyond the relevant policy limit; and* *(c) the costs beyond the relevant policy limit increase the costs to the Service Provider of providing the Reference Service.* *For this Insurance Cap Event:* *(a) the relevant policy limit is the greater of:* *(i) the Service Provider's actual policy limit at the time of the event that gives, or would have given, rise to the claim; and* *(ii) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the Access Arrangement Period in which the relevant insurance policy is issued;* *(b) a relevant insurance policy is an insurance policy held during this Access Arrangement Period or a previous period in which access to the pipeline services was regulated; and* *(c) the Service Provider will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party of the Service Provider in relation to any aspect of the Network or the Service Provider's business.*
Terrorism event	***Terrorism Event*** *means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear);*
Natural disaster event	***Natural Disaster Event*** *means any fire, flood, earthquake or other natural disaster;*

Event name	Event specification
Gas supply shortfall event	***Gas Supply Shortfall Event*** *means an event outside of the control of the Service Provider which:* *(a) causes the Service Provider (acting reasonably in the circumstances) to take action to safely manage the impact or potential impact on the Network of materially insufficient gas being available for injection into the Network, including in the circumstance where the pressure of Gas at any Receipt Point drops or threatens to drop below the minimum receipt pressure at that Receipt Point; and* *(b) results in an interruption or reduction in the provision of the Reference Service.*
Insurer Credit Risk Event	***Insurer Credit Risk Event*** *means the insolvency of an insurer of the Service Provider, as a result of which the Service Provider:* *(a) incurs materially higher or lower costs for insurance premiums than those allowed for in the AER's final decision in relation to this Access Arrangement; or* *(b) in respect of a claim for a risk that would have been insured by the insolvent insurer, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under the insolvent insurer's policy; or* *(c) incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer.* *For the purpose of this event, an event is considered to materially increase costs where the event has a cost impact of either:* *(d) in at least one of the Financial Years of the Access Arrangement Period that the costs are incurred, at least one per cent of the smoothed forecast revenue specified in the Access Arrangement Information for the corresponding year that the costs are incurred; or* (e) *in total over the 2015-20 Access Arrangement Period, equal to or greater than 0.5 per cent of the smoothed forecast revenue specified in the Access Arrangement Information*.
Network user failure event	***Network User Failure Event*** *means the occurrence of an event whereby a User becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another User, but excludes costs that could be the subject of a pass through amount pursuant to rule 531 of the National Gas Rules or section 167 of the National Energy Retail Law.* *For the purposes of this event the Service Provider may seek to pass through amounts that the Service Provider is entitled to be paid (but which are or will be unpaid as a result of a Network User Failure Event) for the provision of the Reference Service, including the revenue impact the Service Provider sustains or will sustain as a result of those unpaid amounts. For the avoidance of doubt, references to incurring "costs" in clause 3.4 include these amounts*

12.3.2 MATERIALITY THRESHOLD

682. To address these issues, JGN proposes the following revised threshold specification[338]:

> *The Service Provider may seek the approval of the AER to pass through costs where:*

338 For clarity, these thresholds do not apply in the case of events that fall within any of the automatic adjustment factors. See further section 15.1.1.

> *(i) as a result of a Cost Pass Through Event (other than a Network User Failure Event), the Service Provider has incurred, or is likely to incur, higher costs in providing the Reference Service than it would have incurred but for that event and those costs are or are reasonably estimated to be:*
>
> > *(A) in total over the Access Arrangement Period, equal to or greater than 0.5 per cent of the smoothed forecast revenue specified in the Access Arrangement Information; or*
> >
> > *(B) in at least one of the Financial Years of the Access Arrangement Period that the costs are incurred, equal to or greater than one per cent of the smoothed forecast revenue specified in the Access Arrangement Information for the corresponding year that the costs are incurred; or*
>
> *(ii) as a result of a Network User Failure Event, the Service Provider has incurred or is likely to incur higher costs in providing the Reference Service than it would have incurred but for that event, regardless of whether those costs satisfy the thresholds in clause 3.4(b)(i)(A) or 3.4(b)(i)(B) above.*

683. Should this threshold be met for any event, it does not follow that those costs should be automatically approved under the pass through mechanism in JGN's AA. Rather, meeting this threshold gives JGN the right to make an application to the AER to pass through its costs, in accordance with the mechanism specified in AA clause 3.4. Significant supporting information is then required to be provided to substantiate the application. The AER must then make its determination about the event, in accordance with the decision-making framework set out in clause 3.4, including the list of relevant factors specified in clause 3.4(j).

684. Under JGN's revised threshold specification, referring to the example in section 12.2:

- events 1 and 2 are clearly open to a pass through application because in at least one of the years that costs are incurred (i.e. 2016-17) the costs incurred meet the materiality threshold
- event 3 is clearly open to a pass through application because the total costs over the AA period ($20M) is greater than half a per cent of forecast revenue over the AA period (0.5 per cent x $2.5B = $12.5M).
  - however, if the annual cost for event 3 was less than $2.5M p.a. (total cost less than $12.5M) JGN would not be able to submit a pass through application.

685. If the AER does not approve our proposal, we would request that the ambiguity in the current threshold (where the threshold applies to all years in which costs are incurred) is removed.

686. Finally, JGN accepts that this materiality threshold applies to a regulatory change event related to carbon policy (to the extent that those costs are not picked up by the automatic adjustment factor).

13. LIST OF SUPPORTING INFORMATION

No.	Document title	Author
1.1	Relevance of JGN's commercial operating environment to the AER's consideration of JGN's AA revision proposal	JGN / HoustonKemp
1.2	AER customer engagement for JGN AA review	JGN
1.3	The draft decision – long-term customer consequences	JGN
1.4	Response to draft decision on JGN's revised AA	JGN
1.5	Response to draft decision on JGN's revised RSA	JGN
1.6	Confidentiality claims	JGN
1.7	Pre-lodgement engagement material and correspondence	JGN
3.1	Demand forecasting report – response to draft decision	Core Energy
3.2	Core Energy model and supporting spreadsheets – revised JGN demand and customer forecast	Core Energy
3.3	JGN demand forecasts model – updated	JGN
3.4	Frontier Economics review of AER demand forecasts	Frontier Economics
3.5	HoustonKemp review of AER demand forecasts	HoustonKemp
3.6	Energy Savings Scheme information paper	NSW Government
4.1	JGN capex forecast model – updated	JGN
4.2	JGN market expansion unit rate derivation model	JGN
4.3	Network projects – response to the draft decision	JGN
4.4	Report on in-line inspection of the Wilton to Horsley Park trunk pipeline	Asset Engineering Solutions
4.5	Letter from AEMO - Gloucester supply	AEMO
4.6	Letter from AGL – Gloucester supply	AGL
4.7	Letter from Ausmeter – metretek	Ausmeter
4.8	Letter from Epitomy – meter data loggers	Epitomy
4.9	Letter from GE Energy Management – GENe SCADA	GE Energy Management
4.10	Capitalised overheads	JGN
5.1	Updated cost escalators for JGN	BIS Shrapnel
5.2	Updated productivity assessment for JGN	Economic Insights
5.3	Debt raising transaction costs – updated report	Incenta
5.4	Operating expenditure step changes report	JGN
5.5	JGN Opex forecast model – updated	JGN
6.1	Legal advice on WACC clawback	G+T
7.1	Return on equity	JGN
7.2	Beta and the Black CAPM	SFG

No.	Document title	Author
7.3	Dividend discount model	SFG
7.4	Fama-French model	SFG
7.5	The required return on equity for the benchmark efficient entity	SFG
7.6	Further update on the required return on equity from Independent expert reports	Incenta
7.7	Historical estimates of the Market Risk Premium	NERA
7.8	Empirical performance of the Sharpe-Lintner and Black CAPMs	NERA
7.9	Grant Samuel letter on the AER draft decision	Grant Samuel
7.10	Return on debt	JGN
7.11	Future averaging periods	JGN
7.12	Return on debt expert report	CEG
7.13	New issue premium	CEG
7.14	Return on debt transition arrangements under the NGR and NER	SFG
7.15	JGN rate of return forecast model – updated	JGN
8.1	Gamma – response to the draft decision	JGN
8.2	Estimating gamma for regulatory purposes	SFG
10.1	JGN forecast revenue model	JGN
10.2	JGN reference tariffs and customer outcomes	JGN