Jemena Gas Networks (NSW) Ltd

2015-20 Access Arrangement Information

Appendix 7.3

Operating expenditure step changes report

Public

30 June 2014

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GLOSSARY

BAU	Business as Usual
FTE	Full Time Equivalent
JGN	Jemena Gas Networks (NSW) Ltd
NECF	National Energy Customer Framework
NERR	National Energy Retail Rules
NGR	National Gas Rules
NGTNC	Natural Gas, the Natural Choice
NILS	No Interest Loan Scheme
RIN	Regulatory Information Notice
SGSPAA	SGSP (Australia) Assets Pty Ltd
WOH	Whole of House Heating

OVERVIEW

Jemena Gas Networks (NSW) Ltd (**JGN**) has applied a base, step and trend approach to forecast its controllable operating expenditure (**opex**) requirements for the 2015-20 AA period. The base year is regulatory year 2013-14.

JGN proposes recurrent and non-recurrent opex step changes. A summary of the proposed step changes are set out in Table OV-1.

This appendix first describes our framework for assessing proposed step changes against the National Gas Rules (**NGR**) requirements, and assesses and details each step change in turn.

Table OV–1: 2015-20 step change proposal summary ($2015, $millions)

Proposed step change	Total expenditure (2015-20)	Key driver(s)	Recurrent/non-recurrent
National Energy Customer Framework	6.73	New regulatory obligation	Recurrent and non-recurrent elements
Customer engagement	0.49	New regulatory obligation, good industry practice	Recurrent and non-recurrent elements
2020 AA project	7.85	Capitalisation approach	Non-recurrent
Marketing	6.56	Cost-benefit analysis	Recurrent
Insurance premiums	0.56	Cost-benefit analysis	Recurrent
Annual regulatory reporting	1.92	New regulatory obligation	Recurrent
Total	**24.04**		

1. ASSESSMENT FRAMEWORK

1. In preparation for the 2015-20 Access Arrangement (**AA**), JGN identified opex activities that will need to be undertaken during the 2015-20 AA period but are not fully captured (or captured at all) in 2013-14 opex. These activities were assessed against the requirements of rule 91(1) of the NGR.

> **Rule 91 Criteria governing operating expenditure**
>
> 1. Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.
> 2. The AER's discretion under this rule is limited.

2. Assessment against these requirements and considerations reduced the number of proposed opex step changes to six activities. JGN briefed AER staffers on its approach to step changes and its initial list of step changes in November 2013.

3. JGN also notes that the AA Regulatory Information Notice (**RIN**) requests additional information relevant to proposed step changes. This information is provided in JGN's response to the AA RIN.

4. JGN considers that each proposed step change reflects expenditure required by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. JGN does consider that these step changes are captured by the rate of change escalation applied to the opex forecasts prepared using the base, step and trend method.

2. NATIONAL ENERGY CUSTOMER FRAMEWORK

2.1 DRIVER

5. JGN is required to comply with full National Energy Customer Framework (**NECF**) requirements under the National Energy Retail Rules (**NERR**) by 1 July 2015. These requirements are significant new regulatory requirements that would not be captured by the rate of change element of trend escalation.

6. The driver of this step change is a significant chanage in JGN's regulatory obligations. The costs are not captured in base year costs because the new obligations commence in the new AA period, and are not in the nature of trend escalation for scale or scope.

2.2 IMPACTED OPEX ACTIVITIES

7. There are two categories of activity that are impacted by this driver.

2.2.1 CUSTOMER SUPPORT AND BILLING

8. Under full NECF, customers can seek a range of gas services directly from JGN that are currently performed by, or administered through, gas retailers. JGN will need to expand its service delivery capabilities and capacity to manage increased enquiries, transactions and complaints as customers move their service expectations from retailers to JGN for certain services. In order to meet full NECF compliance obligations, JGN will need to:

- maintain and provide access to customer data, determine, track and notify customer classification and occupancy status and ensure compliance with privacy and related laws
- maintain systems to notify retailers and customers of planned and unplanned gas supply interruptions, de-energisations and disconnection of premises
- implement a billing and debt collection system to recover new connections and alterations charges
- manage network revenue recovery consistent with NERL/NERR entitlement of the retailers to recover distributor charges from the customer and administer retailer credit support requirements

9. This step change relates to operational resourcing of non-automated business processes to support full NECF compliance between 1 July 2015 and 30 June 2016.

10. JGN intends to implement the minimum required system changes to comply with full NECF, in light of the prudent decision to replace the Customer Management Framework on GASS+ by March 2016. This replacement will incorporate the functionality required to comply with full NECF.

2.2.2 CUSTOMER CONNECTIONS

11. The costs of processing basic and standard connection applications submitted directly by builders, plumbers and developers (bypassing the retailer) are recovered by JGN's "Connect Direct" service through an administrative fee, which has been payable by the connection applicant.

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12. The way in which these costs are recovered will need to change in the next AA period, because JGN will be subject to a range of new obligations under the connection for retail customers' provisions in Part 12A of the NGR from 1 July 2015. In short, these provisions are expected to:

- prevent Connect Direct from recovering the costs of processing basic and standard connection applications from applicants
- trigger both an increase in the number of basic and standard connection applications coming directly to Connect Direct (rather than via retailers) and a change in the type of customer (e.g. more households) to whom the service must be provided because:
  - standing offers for basic and standard connections must be made available to all retail customers
  - retailers may encourage customers to come directly to JGN (rather than acting as an intermediary) if there is no administrative fee.

13. Connect Direct will require additional resources to deal with the expected increase in connection applications and different types of customers.

2.3 PRUDENCE ASSESSMENT

2.3.1 CUSTOMER SUPPORT AND BILLING

14. JGN has considered the following options:

1. do nothing. This option would result in non-compliance with full NECF obligations until delivery of replacement to GASS+ customer management framework.
   a) this option has high regulatory and reputational risk with full NECF customer service expectations not deliverable.
2. approach the NSW Government to seek agreement to delay commencement of full NECF requirements until the new Customer Management System delivery and implementation is completed.
   a) this option is unlikely to be agreed to by the NSW Government and would delay the benefits of full NECF to customers.
3. bring forward the development and delivery of the new Customer Management System in time for full NECF.
   a) this option has a high delivery and implementation risk due to constrained time and internal resources to meet the full NECF commencement date. JGN has assessed the risks of accelerating the project delivery timing and adopted a staged approach.
4. design and build Customer Relationship Management, Customer Self-Service or fully automated functionality into GASS+ to support full NECF compliance from 1 July 2015.
   a) this option require an intensive capital investment in GASS+ (estimated \$5M to \$12M) to achieve a potential lower opex (\$0.8M to \$0.5M per annum) in a system which is to be replaced during the RY16 period and therefore be of a short operational lifetime.
5. carry out targeted minimal changes to GASS+ and support full NECF through manual operational processes.
   a) this option is considered an efficient and effective means for JGN to meet full NECF compliance obligations during RY16 until delivery of GASS+ replacement Customer Management Framework by

March 2016. Risk-managed transition to the Customer Management Framework would see resources phased out of the business in June 2016.

15. Option 5 is therefore the preferred option because the other options are not considered viable for the reasons identified.

2.3.2 PART 12A CONNECTIONS

16. JGN has considered the following options:

1. do nothing.
   a) This option would result in non-compliance with full NECF obligations which has high regulatory and reputational risk with full NECF customer service expectations not deliverable.
2. efficiently increase operational resourcing to provide the new services of the AA period.

17. Option 2 is considered the only viable option to address the need.

2.4 OPEX STEP CHANGE FORECAST

2.4.1 CUSTOMER SUPPORT AND BILLING

18. JGN's customer services team currently receives approximately 30,000 calls per annum covered by three full time equivalent (**FTE**) employees. This translates to an average of around 40 calls per day per FTE employee. For more complex calls involving consumption enquiries, maintenance of customer data, and complaints handling (which reflect the full NECF impact), the effective handling rate is lower, at 30 calls per day.

19. JGN has customer service key performance indicators to answer calls within certain times, minimise call abandonment rates, target enquiry response times and complaint resolution times.

20. In the context of full NECF obligations and the potential for retailers to refer end use customers directly to JGN for distribution services, eight FTEs would have the capacity to handle approximately 60,000 more complex calls per annum. This is considered reasonable in an environment of rising gas prices and the potential for retail price deregulation, following the NSW Government announcement on 7 April 2014 to remove retail electricity price regulation.

21. For manual billing production, three FTEs would have the capacity to produce approximately 12,000 distribution billing transactions per annum, which would cover 0.1 per cent of customers that could be monthly-billed or 0.25 per cent of customers which could be quarterly billed directly for distribution services.

22. The FTEs will perform multiple duties to flexibly resource the demand for customer service activities.

23. Following the implementation of new self-service and automated customer management systems, it is expected that a nominal telephone handling capability will be required to provide services to customers who elect not to, or are unable to, access self-service portals. Three FTEs would have the capacity to handle approximately 20,000 to 30,000 calls per annum, equating to one call per annum from 1.7 per cent to 2.5 per cent of JGN's 1.2M connections base.

24. The team leader role is to produce effective and NECF-compliant delivery of customer services from a newly formed team to an increasing end use customer base where JGN will have a direct service relationship in lieu of retailers. The increased support costs for system functionality and business processes are necessary to deliver full NECF compliance.

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2.4.2 PART 12A CONNECTIONS

25. JGN has developed a forecast of the costs that a prudent service provider acting efficiently would incur in providing the re-scoped connection service over the AA period. This has taken into account:

- the increase in the number of applications that Connect Direct will receive and the different types of customers that will approach Connect Direct when Part 12A comes into effect
- the operational resources that will be required to service the projected number of applications and the different types of customers.

26. The forecast does not include the costs of providing services to negotiated connection applicants, because under Part 12A these costs can still be recovered from the applicant.

27. JGN estimates that Direct Connect's market share will increase significantly in the first two years of full NECF, to around 80 per cent in RY18 and then holding steady. JGN has made this estimate based on market behaviour experienced when JGN first introduced the Connect Direct service. In 2009, AGL charged between $300 and $600 ($nominal) for residential connections and $1,100 ($nominal) for commercial connections. JGN set a lower fee—$220 for residential and $550 ($nominal) for commercial connections. As a result, in 2010-11 JGN's market share grew to 60 per cent. This suggests:

- builders and developers develop a relationship with their connection provider and may take time to switch in response to price signals, and/or
- there are information barriers that prevent all customers understanding the connection options available to them.

28. JGN has taken these circumstances and behaviours into account, including that under full NECF its connection fee would fall to $0 and basic/standard connection processes would be streamlined and more accessible for customers. JGN considers that an increase to 80 per cent market share would be reasonable taking these factors into account. Additional headcount to service the increased market share is incremental to the current base headcount of seven people in the Connect Direct team.

Table 2–1: Assumptions for Part 12A connection costs

	Assumptions					
	As at Dec 13	2015-16	2016-17	2017-18	2018-19	2019-20
Connect Direct market share (%)	21	50	65	80	80	80
Offers made – new homes, E-G, Commercial (# p.a.)	7,300	17,400	22,620	27,840	27,840	27,840
Additional headcount required (incremental, #)	0	5	2	1	0	0
Average remuneration (inc. on-cost) ($2015)	0.11	0.11	0.11	0.11	0.11	0.11

29. Table 2–2 sets out the NECF step change forecast. Note that, for customer support and billing, costs incurred from 2016-17 reflect those activities that will not be captured by the Customer Management Framework upgrade to GASS+.

Table 2–2: 2015-20 NECF step change forecast ($2015, millions)

	Step change forecast					
	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Customer Support & Billing						
FTEs for consumption enquiries, manual extraction, analysis and maintenance of customer data, complaints handling and production of distribution services charges	0.82	0.31	0.31	0.31	0.31	2.05
FTEs for manual billing production of distribution service charges compliant with NECF obligations	0.31	0.00	0.00	0.00	0.00	0.31
1 FTE for management of customer service strategy and operations	0.15	0.00	0.00	0.00	0.00	0.15
1 FTE for process and systems support costs for GASS+ NECF functionality	0.15	0.00	0.00	0.00	0.00	0.15
Sub-total	**1.44**	**0.31**	**0.31**	**0.31**	**0.31**	**2.67**
Connections under Part 12A						
FTEs to assess and process connections	0.56	0.79	0.90	0.90	0.90	4.06
Total step change	**2.00**	**1.10**	**1.21**	**1.21**	**1.21**	**6.73**

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3. CUSTOMER ENGAGEMENT

3.1 DRIVER

31. The AER has issued consumer engagement guidelines which set out the AER's expectations for customer engagement when preparing a price submission. This is reflected in the AER's media release that accompanied the final guideline:

> *Energy and gas network businesses will need to demonstrate they have considered the needs and interests of their consumers when putting up spending proposals under new measures published by the Australian Energy Regulator.*

32. This represents a turning point in consumer and stakeholder engagement across the industry, evidenced by the ramp up of consumer engagement activity across energy network businesses.

33. The driver of this step change is a change in regulatory obligations and advancement in good industry practice. With expected step increases in wholesale gas prices, JGN also needs to escalate its customer analytics to understand potential customer responses to rising gas prices. The costs are not captured in base year costs, and are not in the nature of trend escalation for scale, scope or productivity change.

3.2 IMPACTED OPEX ACTIVITIES

34. There are material ongoing costs associated with meeting the level of customer engagement reflected in the AER's guideline. In 2013-14, a significant portion of these costs will be captured as part of the AA project and capitalised for regulatory purposes (and are therefore reflected in the AA project step change). However, certain additional incremental activities will not, specifically:

- the targeted market research JGN intends to undertake in RY16 and RY18
- the ongoing management of the JGN Customer Council, in those years when these activities are not fully captured in AA project costs (i.e. RY16, RY17, RY18 and RY20).

3.3 PRUDENCE ASSESSMENT

35. There are material ongoing costs associated with meeting this level of engagement.

3.3.1 MARKET RESEARCH

36. JGN intends to undertake periodic market research over the next AA period (scheduled for RY16 and RY18) to evaluate customer satisfaction with its service performance and engagement strategies. This market strategy would focus on surveying business and residential customers using both quantitative (on-line/telephone surveys) and qualitative methodologies (deliberative forums). It would also cover more specific qualitative research (in-depth interviews) with JGN's key stakeholders (self-contracting users, industrial customers, retailers and the NSW Government). This research will focus on JGN's business as usual activities, with separate and specific market research to engage customers around JGN's five-yearly price and service reviews.

37. If JGN does not undertake this activity, JGN will not acquire up-to-date base line data and insight that it has recently acquired for the 2015-20 AA review regarding the preferences of its customer base. The only valid way to do this for JGN's larger customer cohorts is to undertake periodic market research (both qualitative and

quantitative) to understand how JGN is regarded in the community and how its service delivery and engagement strategies could be improved to reflect customer preferences over time. It will be important for JGN to maintain contemporary data on customer price and service preferences over the AA period, particularly as wholesale gas price rises start to feed into customer bills.

3.3.2 CUSTOMER COUNCIL

38. This activity involves the ongoing management of the JGN customer council in the years when these costs are not captured in the AA project costs (ie. in RY16, RY17, RY18 and RY20). The costs in RY19 are captured in the 2020-25 AA review step change noting that the meetings are likely to be dedicated to 2020-25 AA issues.

39. Additional costs are required to ensure JGN accords its new Customer Council with the minimum necessary support to reflect the ongoing commitment that Council members are making to attend quarterly meetings. The costs for this include venue hire, simple catering, membership fees and basic secretariat support and are in line with industry standards for managing standing groups of external representatives.

3.4 OPEX STEP CHANGE FORECAST

40. The forecasts have been derived as follows:

- Customer Council costs are based on quarterly meetings at $0.015M each (reflective of the actual cost of holding a Customer Council meeting)
- market research costed at $0.12M per study, based on the estimated cost of undertaking a deliberative forum (which is based on the actual cost of JGN undertaking the deliberative forums that informed the 2015-20 AA submission, that was procured through a competitive request for proposal).

Table 3–1: 2015-20 customer engagement step change forecast ($2015, $millions)

	Step change forecast					
	2015-16	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**Total**
Customer council	0.06	0.06	0.06	0.00	0.06	0.24
Market research	0.12	0.00	0.12	0.00	0.00	0.24
Total step change	**0.18**	**0.06**	**0.18**	**0.00**	**0.06**	**0.49**

4. 2020 ACCESS ARRANGEMENT PROJECT

4.1 DRIVER

41. The driver of this step change is a change in approach to capitalising the costs of the access arrangement project. The costs are not captured in base year operating costs and are not in the nature of trend escalation for scale, scope or productivity change.

4.2 IMPACTED OPEX ACTIVITIES

42. The next AA for JGN's gas distribution network will commence on 1 July 2015, and is expected to expire on 30 Jun 20. The next AA period would commence on 1 July 2020. Under clause 52 of the NGR, JGN must prepare and submit to the AER a submission comprising:

- JGN's proposed AA revisions, to apply in the new AA Period (**AA Proposal**)
- an AA information document (AAI), that provides background information about the AA Proposal, and
- additional information supporting the AA Proposal (which might include, for example, reports from expert advisors relating to particular aspects of the AA Proposal).

43. The 2020 AA proposal will be lodged with the AER by 30 June 2019. A final decision would be due in May 2020.

44. The following costs are excluded from this step change:

- non-incremental costs (e.g. BAU finance resources seconded to the project)
- merits and/or judicial review costs
- any customer engagement costs captured by the customer engagement step change.

4.3 PRUDENCE ASSESSMENT

45. JGN has considered the following options to address the need:

1. no change (continue to capitalise)
   a) this option would not meet the expectation that these costs be treated as opex.
2. do not submit a 2020 access arrangement
   a) this is not considered a viable option—it would result in breach of clause 52 of NGR. This rule is a civil penalty provision. A poor regulatory outcome will have a significant negative impact on revenues, profitability and corporate reputation.
3. treat the access arrangement costs as opex.
   a) this option would meet the AER's expectation that these costs be treated as opex.

46. Option 3 is therefore the preferred option.

4.4 OPEX STEP CHANGE FORECAST

47. The step change forecast is based on actual and forecast incremental costs for preparing the current 2015-20 AA submission. JGN has assumed that the incremental cost of the 2015 AA project is comparable to the incremental costs of the 2020 AA project. JGN considers this is a conservative estimate as regulatory requirements for access arrangements tend to increase substantially from review to review. The forecast cost for the 2020 AA Proposal has been developed:

- for RY18, actual costs for RY13
- for RY19
  - actual costs for RY14 (June 13 to March 14)
  - cost estimates for April 14 to June 14 (remainder of RY14)
- for RY20, cost forecasts for RY15.

48. The estimate for April 14 to June 14 is based on known activities to occur, which will be updated in response to the AER's draft decision. The forecast for RY15 is based on a bottom up build forecast associated with responding to AER questions on the AA and AAI, and responding to the AER's draft decision.

Table 4–1: 2015-20 AA project step change forecast ($2015, $millions)

	Step change forecast					
	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Initial scope	0.00	0.00	0.04	0.00	0.00	0.04
AA preparation	0.00	0.00	0.00	4.50	0.00	4.50
Review and final decision	0.00	0.00	0.00	0.00	3.31	3.31
Total step change	**0.00**	**0.00**	**0.04**	**4.50**	**3.31**	**7.85**

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5. MARKETING

5.1 BACKGROUND

49. Natural gas is a fuel of choice in NSW which competes with electricity and other fuels. This competition is exacerbated by the warmer climate in NSW relative to colder states such as Victoria where electrical appliances are less effective for heating.

50. Natural gas must be competitive to attract new customers and encourage them to purchase additional natural gas appliances. Marketing research tells us that potential customers see the upfront costs of purchasing new natural gas appliances and getting them installed as barriers to connection/using natural gas, particularly when they have many alternatives to natural gas appliances. Incentive rebate programs have proven to be a highly effective strategy in addressing this barrier and are able to be targeted to influence customer behaviour by helping them with the upfront costs of buying new natural gas appliances.

51. JGN has developed a marketing program called 'Natural Gas, the Natural Choice' (**NGTNC**) to increase new customer connections as well as the sale and installation of natural gas appliances in NSW by establishing natural gas as a highly desirable energy option. It does this by promoting natural gas as a fuel of choice and working with alliance partners to promote the sale of gas appliances via incentive payments.

5.2 DRIVER

52. The driver of this step change is the net benefit associated with countering the deterioration in market conditions that is expected to occur over the next AA period through an enhanced marketing program.

53. Market conditions are expected to deteriorate over the next AA period for the following reasons:

- the relative competitiveness of gas vis-à-vis electricity is expected to deteriorate as a result of both rising wholesale gas prices and lower wholesale electricity prices/electricity network charges[1]
- there is expected to be a shortfall in gas supplied to NSW from 2018[2] and while this is only expected to affect larger customers, expectations of gas shortages could cause smaller customers to reduce consumption[3]
- government policies are no longer as favourable to gas as they were in the past (e.g. the NSW Government has decided not to proceed with the phase-out of emission intensive electric hot water systems)
- the perception of the environmental benefits of using natural gas has been damaged by the adverse publicity that coal seam gas production has attracted

54. This deterioration is in addition to the general decline in consumption that is occurring due to energy and thermal efficiency improvements, milder weather and increased penetration of reverse-cycle air conditioners.

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1 See for example, Core's demand projections (appendix 5.1) and Grattan Institute, *Getting gas right – Australia's energy challenge, June 2013*, pp. 10-11 for an analysis of the effect of higher wholesale gas prices on retail prices and AEMC, 2013 Electricity Price Trends, December 2013 for analysis of what is expected to occur with electricity prices. See also IPART's review of regulated electricity and gas retail prices.

2 See AEMC, *2013 Gas Statement of Opportunities*, November 2013.

3 See for example, SMH, *NSW gas shortage will hit business first*, 2 December 2013.

55. While the current marketing program has been effective in helping to address the trend decline in residential connections and average loads in the current AA period, there is a strong case to increase the scale and scope of the incentive rebate scheme in the next AA period to try and counter some of the deterioration and, in particular, the reduction in the competitiveness of gas vis-à-vis electricity.[4]

56. Customers have expressed support for marketing and have acknowledged the benefits, as noted in appendices 1.4 and 1.5.

57. The costs of this step change are not captured in base year operating costs and are not in the nature of trend escalation for scale, scope or productivity change.

5.3 IMPACTED OPEX ACTIVITIES

58. To counter the projected decline in residential demand, JGN intends to expand the scope and scale of the incentive rebate scheme by implementing the following measures:

- defend our core market segments by increasing increase the incentive rebates payable on whole of house heating (**WOH**), hot water systems and flued heating
- expand the current scope of incentive offers by introducing an incentive rebate for unflued heating
- counter the incentives offered by electrical appliance manufacturers by introduce introducing an new incentive payment of $300, which will be paid to dealers where an appliance sale results in new E to G connections (note that 16 per cent of all appliance sales are assumed to result in new E to G connections
- become more responsive to the timing of customers' appliance purchasing decisions by increasing the number of campaigns run in each year and the channels through which rebates are distributed
- ensure equity across our customer base by introducing a program for vulnerable customers to further encourage the take up of efficient gas appliances, based on customer feedback on the benefits of assisting vulnerable customers in managing their energy consumption .

59. The objective of this program is to stop half of the assumed reduction in residential demand, so that by RY 2020 demand remains around 23.2 PJ. This will require a 160 TJ per annum increase in residential demand between 2015-16 and 2019-20, having regard to customer growth over the same period.

60. The vulnerable customer program includes:

- $0.05M p.a. to fund a part-time headcount (50 per cent of a $0.1M resource) to prepare a vulnerable customer strategy, manage relationships with external partners (for example Land and Housing Corporation NSW) and develop funding programs
- $0.07M to fund programs developed as part of the vulnerable customer strategy with external partners as outlined in above

[4] The proposed changes have focused on the incentive rebate scheme because the benefits of this scheme can be measured more readily than the NGTNC campaign and the scheme can be linked more directly to countering the effects of the reduction in the competitiveness of gas vs electricity.

- $0.08M to cover cost of providing funding of $1M to a No Interest Loan Scheme (**NILS**)[5]—under such a scheme the funds would eventually be repaid to JGN so the cost is the time value of money and conservatively assumes no bad debts.

5.4 COST BENEFIT ASSESSMENT

61. Four options have been considered:

1. do nothing
2. expand the scale and scope of the incentive rebate scheme
3. increase expenditure on the NGTNC campaign.
4. combine options 2 and 3.

62. When used in conjunction with the current level of expenditure on the NGTNC campaign, Option 2 would be the most effective option because it is a more targeted and adaptable approach and the benefits can be more readily measured. This option will involve:

- increasing the incentive rebates payable on WOH, hot water systems and flued heating by 128 per cent in real terms from 2015-16 and maintaining them at these levels through to 2019-20
- introducing a new incentive rebate for unflued heating
- introducing a new incentive for dealers where an appliance sale results in new E to G connections
- increasing the number of campaigns that are run in each year of the next AA period
- implementing a low interest loan program for vulnerable customers.

63. To determine whether the proposed step change would satisfy rule 91 of the National Gas Rules, we have employed a similar approach to Envestra (Victoria) and examined whether:

- the level of each of the proposed rebates is such as would be incurred by a prudent operator acting efficiently, and, in accordance with good industry practice; and
- the relevant reference tariff is likely to be lower as a result of expanding the scale and scope of the rebate scheme and attracting additional load.

5.4.1 COSTS

64. To calculate the projected cost of the new incentive rebate program, it has been necessary to make reasonable assumptions about the following matters:

- appliance sales will reach over 9,600 in RY16 and remain around this level for the remainder of the next AA period:

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5 A NILS provides individuals and families on a low income access to safe, fair and affordable credit, with loans generally available for the purchase of essential goods and services. Customer and stakeholder feedback was that NILS schemes are cost-effective ways of assisting vulnerable customers overcome some of the barriers in replacing or upgrading their appliances.

  - this represents a 114 per cent increase from the 2013 level of appliance sales—or a 29 per cent p.a. increase for WOH, flued heating and hot water systems between RY13 and RY16 and 600 new sales of unflued heaters.

- the take-up rate for the incentive rebates for each of the appliances subject to the rebate scheme

  - over the period RY11-13, the take-up rate for WOH rebates ranged from 26 per cent to 31 per cent, while the take-up rate for flued heating rebates ranged from 38 per cent to 58 per cent and for hot water system rebates from 79 per cent to 80 per cent. Given the expected deterioration in the competitiveness of gas verus electricity, the take-up of rebates is expected to be higher than it has been historically, as customers use the rebate to offset the effect of higher gas prices. It has been assumed that by RY16 the take-up rate will be 1.15-1.8 times higher than the average rates observed over the period RY11-13.

- the number of appliance sales that result in new E to G connections

  - for the purposes of the analysis it has been assumed that 16 per cent of appliance sales result in new E to G connections. This estimate is based on JGN's FY15 incentive investment strategy

- the other costs associated with running the incentive rebate scheme, such as the fulfilment costs (i.e. the costs associated with processing the rebates).

  - JGN is proposing to outsource this work and has received a quote of $0.077M p.a. (incl. GST) to carry out this work. An additional one off cost of $0.037M (incl. GST) will also be payable to alter the design of the current redemption website to provide for the revised scheme. This cost is assumed to be incurred in the current AA period, so has not been included in the step change calculations.[6]

65. Table 5–3 provides further detail on the specific assumptions that have been made about appliance sales and incentive rebates over the next AA period.

Table 5–1: Assumptions for marketing step change cost ($2015)

	Assumption	WOH	Flued heating	Hot Water System	Gas Log Fire	Total
No. of appliances to be sold (A)	29% p.a. increase	2,572	2,144	4,287	600	**9,603**
Incentive rebate per appliance (B)	128% real increase from RY 2013 level	$1,000	$500	$500	$300	**n.a.**
Take up of rebates (C)	1.1-1.8 x higher than historic avg	50%	75%	90%	50%	**n.a.**
Cost of Incentive Rebates (D)	AxBxC	$1,286,197	$803,873	$1,929,296	$90,000	**$4,109,366**
Incentive payment to dealers for new E – G connections ($300) (E)	Ax16%x$300					**$460,962**
Vulnerable customer program (p.a.) (F)	Est.					**$200,000**

6 Pulse, Letter to Danielle Beinart entitled Re: Fulfilment Program, 26 March 2014.

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	Assumption	WOH	Flued heating	Hot Water System	Gas Log Fire	Total
Fulfilment costs (outsourced) p.a. (G)	Based on quote from Pulse					**$76,764**
Total expenditure on incentive rebate programme (H)	**D+E+F+G**					**$4,847,092**
Total expenditure on incentive rebate programme (H) - $2015M	D+E+F+G					$4,969,430

66. To quantify the step change required to implement the new incentive rebate scheme, JGN has compared:

- the opex forecast that would apply if there was no step change (i.e. if the RY 2014 base year expenditure was just rolled forward using the assumed trend increase in opex)
- the forecast that would be required if the new incentive program was implemented.

67. The results of this comparison are set out in Table 5–2. The step change that would be required to implement the new incentive rebate scheme is $6.56 million (real $2015) ($1.31 million p.a.), which is equivalent to a 16 per cent increase from the forecast that would otherwise be available if there was no step change.

Table 5–2: 2016-20 marketing step change forecast ($2015, $millions)

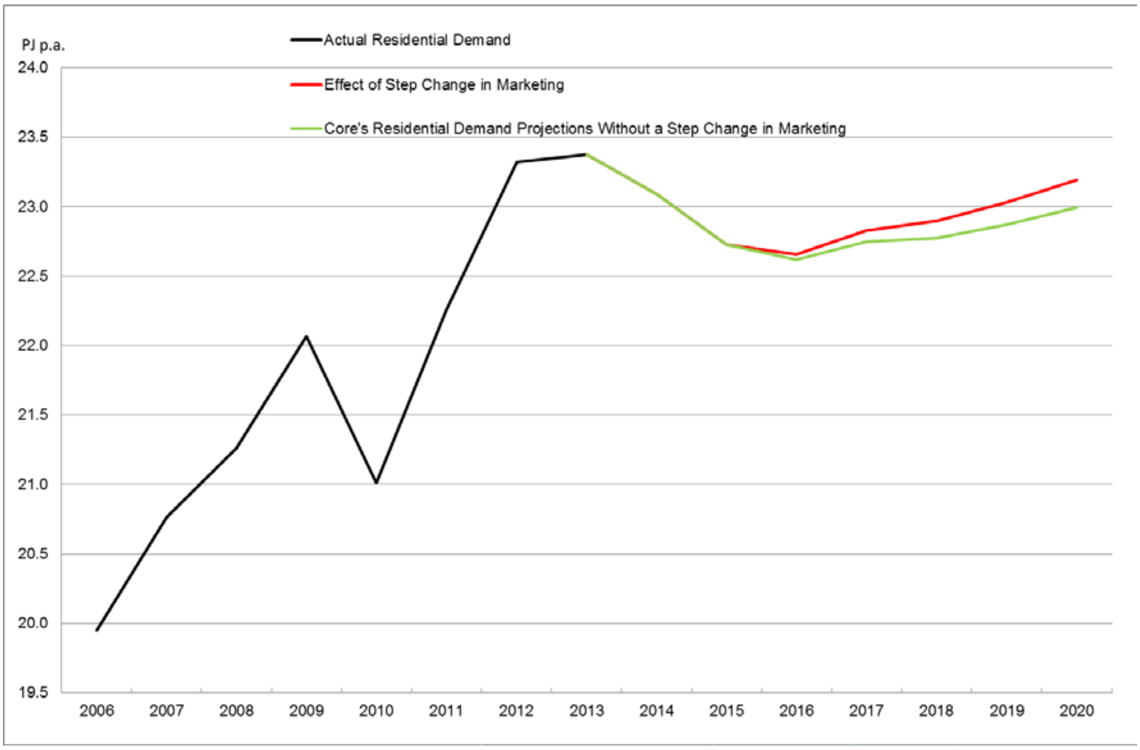
	Step change forecast					
	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Natural Gas, Natural Choice Campaign	3.90	3.97	4.03	4.08	4.13	20.10
Incentive rebate and alliance costs (from table 5–1)	4.97	4.97	4.97	4.97	4.97	24.86
Total Marketing Expenditure (A)	8.87	8.93	8.99	9.04	9.10	44.94
Total Marketing Expenditure if Only Base + Trend Applied (B)	7.56	7.62	7.68	7.73	7.79	**38.37**
Total step change (C) = (A) – (B)	**1.31**	**1.31**	**1.31**	**1.31**	**1.31**	**6.56**

5.4.2 BENEFITS

68. Core Energy's forecasts indicate that without additional marketing expenditure, residential demand could fall by approximately 0.4 PJ between RY13 and RY20 (23.4 PJ vs 23 PJ), with the reduction principally being driven by the reduction in the competitiveness of gas vis-à-vis electricity.

69. Core Energy's residential demand projections assume the continuation of the existing marketing program. The proposed incentive rebate program is expected to result in a 40 TJ increase in Core's demand projections in RY 2016, 80 TJ in RY 2017, 120 TJ in RY 2018, 160 TJ in RY 2019 and 200 TJ in RY 2020. In other words, Core's demand projections are only expected to increase by the step change component. Figure 5-1 illustrates the effect of the new rebate scheme on Core's preliminary residential demand projections.

Figure 5–1: Effect of new rebate scheme on demand forecasts



70. While not shown in this figure, if the step change ceased in RY 2020 and the life of the appliances subject to the rebates was 15 years, residential demand would be 200 TJ higher than what it would otherwise have been between RY20 and RY30, 160 TJ higher in RY 2031, 120 TJ higher in RY 2032, 80 TJ higher in RY 2033 and 40 TJ higher in RY 2034.

71. As Figure 1 indicates, the step change is not be sufficient to counter the effect of the deteriorating market conditions on residential demand, based on Core Energy's projections. However, it will slow the rate of decline and by 2020 demand will be just 180 TJ lower than the level observed in 2013 (~23.4 PJ).

72. The new incentive rebate program is also expected to result in 1,537 new E to G connections in each year of the next AA period. Of the 1,537 new connections, 1,136 are expected to be delivered from the base plus trend level of marketing expenditure and the remaining 401 from the step change in expenditure.

73. As with its residential demand projections, Core Energy's new E to G connection forecast implicitly includes the effect of the current marketing program.[7,8] So the new incentive rebate program is only expected to result in Core Energy's new E to G connections forecast increasing by 401 in each year of the next AA period. Figure 5-2 below illustrates the effect that the step change will have on Core's forecasts of new E to G connections.

[7] In a similar manner to residential demand, Core's report does not quantify the effect that the existing level of marketing expenditure is assumed to have on E to G connections over the next AA period.

[8] As with Core's residential demand projections, the new E to G connections forecast could understate the effect of the marketing allowance approved by the AER on E to G connections given that all of the approved allowance was not spent in RY11-RY13

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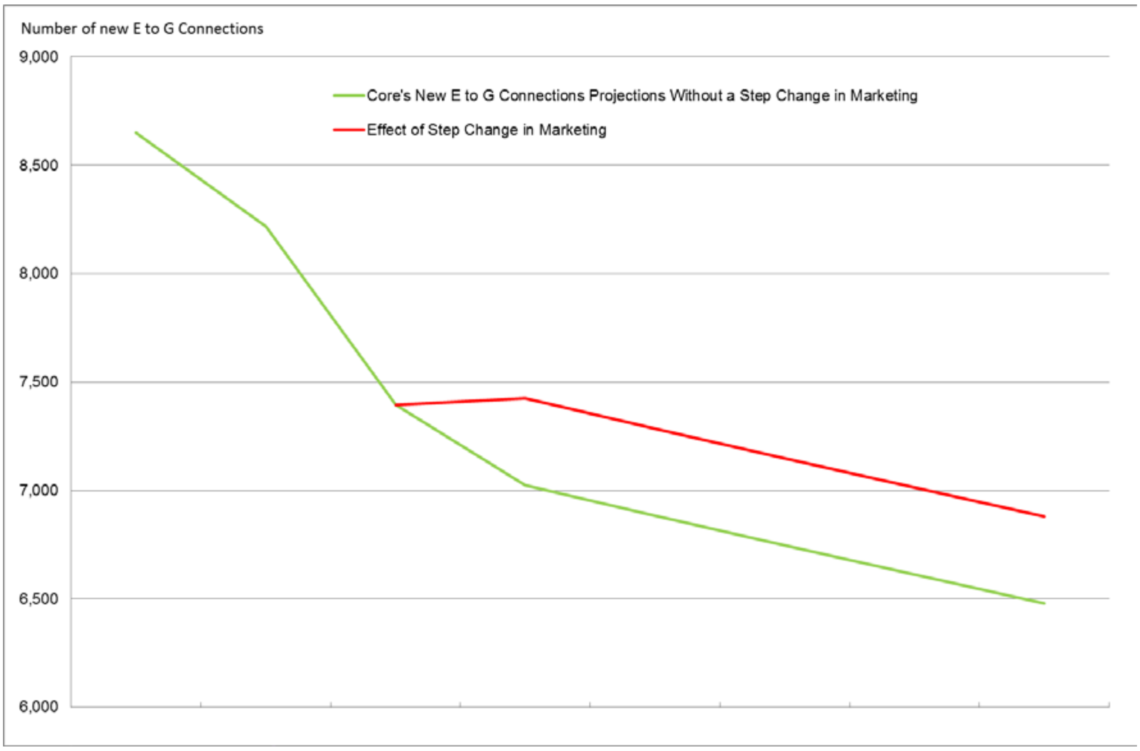
Figure 5–2: Effect of new rebate scheme on E to G connections



74. To determine what effect the step change is likely to have on the reference tariff, we have used the revenue per GJ of gas transported metric as a proxy for the reference tariff. We have then compared:

- the revenue per GJ that would be recovered if there was no step change in the incentive rebate program, which is based on the current base case regulatory modelling ('without' step change state of the world)
- the revenue per GJ that would be recovered if there was a $6.56 million step change in the incentive rebate program ('with' step change state of the world), which resulted in:
  - an additional 401 E to G connections per annum
  - residential demand that was 40 TJ higher in RY16, 80 TJ higher in RY17, 120 TJ higher in RY18, 160 TJ higher in RY19, 200 TJ higher between RY20 and RY30, 160 TJ higher in RY31, 120 TJ higher in RY32, 80 TJ higher in RY33 and 40 TJ higher in RY34.

5.4.3 RESULTS

75. To carry out this analysis, we have adopted a 15-year measurement period and a 10 per cent post-tax nominal rate of return. The other assumptions that have been made are set out in Table 5-1, while Table 5–4 sets out the results of this analysis.

Table 5–3: Assumptions for marketing step change

Input	Assumption
Measurement period	Based on tax life of the appliance (WOH: 20 years, flued and unflued heating: 15 years, hot water system: 12 years)
No. of appliance sales that result in new connections	16% of appliance sales are assumed to result in new connections.

Input	Assumption		
Unit rate per connection	$2,200 per connection		
Opex per customer	$25 per customer		
Revenue	Revenue over the measurement period has been calculated using the residential tariffs applying as at 1 July 2013, which are assumed to escalate at 2.55% over the remaining term of the measurement period.		
Appliance related assumptions			
	Incentive Rebate (real $2014 per appliance)	Incentive Rebate + Allocation of All Other Costs*	Incremental load (per appliance)
WHO	$1,000	$1,077	25 GJ
Flued heating	$500	$577	15 GJ
Hot water	$500	$577	13 GJ
Unflued heating	$300	$377	13 GJ

(1) All other costs includes the outsourcing fulfilment costs, incentive payments to dealers, the allowance made for low interest loans to vulnerable customers and the infill incentive program. These costs ($737,726) have been assumed to be divided equally across the four appliance categories (i.e. $77 per appliance).

Table 5–4: NPV analysis results

Appliance	NPV of Incremental Load (Revenue less connection costs, variable operating costs and tax)	PV Incentive Rebate + Allocation of All Other Costs*	Difference
WHO (20 yrs)	$2,873	$1,077	$1,796
Flued heating (15 yrs)	$1,944	$577	$1,367
Hot water system (12 yrs)	$1,452	$577	$875
Unflued heating (15 yrs)	$1,674	$377	$1,297

76. As Table 5–4 indicates, the benefit associated with the incremental load from each rebate scheme exceeds the cost of the rebate plus the other costs associated with the incentive scheme. It follows, that the level of each of the proposed rebates is prudent.

5.5 OPEX STEP CHANGE FORECAST

77. The total step change that would be required to implement the new incentive rebate scheme is $6.56 million (real $2015) ($1.31 million p.a.), equivalent to approximately $1.00 per customer per annum.

Table 5–5: 2016-20 marketing step change forecast ($2015, $millions)

	Step change forecast					
	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Total step change	**1.31**	**1.31**	**1.31**	**1.31**	**1.31**	**6.56**

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7. ANNUAL REGULATORY REPORTING

7.1 DRIVER

101. The driver of this step change is an anticipated change in regulatory reporting obligations. The costs are not captured in adjusted base year costs and are not in the nature of trend escalation for scale, scope or productivity change.

102. JGN anticipates that the AER will significantly 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 2015 AA RIN.

103. Jemena has previously expressed strong concern with these additional regulatory burden requirements, including whether they a reasonably necessary for the AER to adequately perform its functions and duties. Nonetheless, the AER has imposed the reporting requirements and generally expects onerous assurance requirements to accompany the information provided.

104. As part of the increased reporting requirements, JGN expects that the AER may require an audit of most, if not all, annual data submitted. While the benefits of an audit requirement (in excess of the current statutory declaration requirement) is unclear (and Jemena remains unclear as to the benefit the AER has derived from requiring audits of annual RINs to date), there is a strong possibility that this regulatory requirement will be imposed.

105. These additional requirements are far more than 'regulatory creep'—they require the businesses to initiate formal projects with specific corporate planning and governance processes to manage the new reporting requirements. This reflects the data and assurance requirements (statutory declaration and audit), and that JGN is effectively preparing a separate set of formal company accounts on a regulatory year basis (which are not aligned to JGN's statutory year).

7.2 IMPACTED OPEX ACTIVITIES

106. We expect the scope of JGN's annual RIN to be comparable to JEN's annual RIN.

107. To accommodate the increased requirements, JGN requires four additional FTEs (financial analysts) to backfill current finance and asset management resources. These resources are required to plan, collect, populate and validate expected additional and granular RIN requirements. The staff would also manage the audit and assurance processes. This process covers a six month period from May to November each year. It covers project initiation, resource planning, data and information collection, document preparation, peer and legal review, audit, packaging and sign-off.

108. An audit cost estimate is based on the audit costs of JEN's annual RIN ($85K financial, $45K non-financial) with a $20K carve-out to reflect no requirement for an S-factor audit.

7.3 PRUDENCE ASSESSMENT

109. The options considered were:

1. do nothing

a) this is not considered a viable option. The AER has information gathering powers under sections 48(1)(a) and 55 of the National Gas Law. There are financial penalties for not complying with a RIN as well as reputational and relationship damage.

2. address RIN requirements

a) this requires engagement of backfill staff to support completion of the RIN requirements and the audit process.

110. Addressing the RIN requirements is therefore the preferred option.

7.4 OPEX STEP CHANGE FORECAST

111. We have estimated an annual cost of $265K to complete the annual RIN. This is estimated based on an annual cost of $132K, ($115K + 15 per cent on-costs, $2014) per FTE, required for a 6 month period from May to November ie equivalent to 2 FTEs per annum.

112. We have also estimated a cost of $0.11M for the audit based on JEN's annual costs, with a $20K carve-out for the s-factor component of JEN's RIN.

Table 7–1: 2015-20 annual regulatory reporting step change forecast ($2015, $millions)

	Step change forecast					
	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Total step change	**0.38**	**0.38**	**0.38**	**0.38**	**0.38**	**1.92**