Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 8-6

Operating expenditure step changes

Public

30 April 2015

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1. OVERVIEW

1. Jemena Electricity Networks (Vic) Ltd (**JEN**) has adopted a base, step and trend approach to forecast controllable operating expenditure (**opex**) requirements for the 2016 regulatory period. The proposed opex base year is regulatory (i.e. calendar) year 2014 (**CY14**).

2. JEN proposes both recurrent and non-recurrent opex step changes. Table OV–1 sets out a summary of the proposed step changes, while Table OV–2 outlines the recurrence and categories for each step change.

Table OV–1: JEN's proposed opex step changes summary 2015-20 (real $2015, $millions)

Step change	Step change forecast					
	2016	2017	2018	2019	2020	Total
Service inspection and testing program	1.23	1.23	1.23	1.23	1.23	**6.15**
Overhead switch inspection	0.43	0.43	0.43	0.43	0.43	**2.17**
Enclosed substation inspection and rectification	0.16	0.16	0.15	0.15	0.15	**0.77**
Electricity Distribution Price Review	1.20	0.00	0.00	3.00	3.84	**8.03**
Vegetation management	1.20	1.11	1.11	1.11	1.11	**5.63**
ESV code of practice changes	0.00	0.00	0.83	0.10	0.00	**0.93**
Vulnerable customer initiative	0.22	0.20	0.20	0.20	0.20	**1.01**
Customer engagement	0.52	0.13	0.13	0.00	0.13	**0.93**
New technology trial: pole-top fire detection	0.28	0.28	0.28	0.28	0.28	**1.38**
Demand management opex/capex trade-off	0.11	0.15	0.15	0.15	0.15	**0.71**
Insurance premiums	0.03	0.03	0.03	0.03	0.03	**0.17**
New tariffs	1.23	0.47	0.25	0.25	0.25	**2.46**
Total	**6.62**	**4.18**	**4.80**	**6.94**	**7.81**	**30.34**

Table OV–2: JEN's proposed opex step changes – recurrence and opex categories

Step change	Opex categories			
	Recurrence	Activity or asset	Asset category	Asset subcategory
Service inspection and testing program	Yes	Routine maintenance	Distribution substation, equipment and property	Distribution substation – property
Overhead switch inspection	Yes	Routine maintenance	Overhead asset inspection	All overhead assets
Enclosed substation inspection and rectification	Yes	Routine maintenance	Distribution substation, equipment and property	Distribution substation – property

Step change	Opex categories			
Electricity Distribution Price Review	No	Network overheads	SCS network overheads	SCS other
Vegetation management	Yes	Vegetation management	Zone 1 (low bushfire risk area)	Other vegetation management costs
ESV code of practice changes	Yes	Network overheads	SCS network overheads	SCS network control and operational switching
Vulnerable customer initiative	Yes	Network overheads	SCS network overheads	SCS other
Customer engagement	Yes	Network overheads	SCS network overheads	SCS other
New technology trial: pole-top fire detection	No	Non-routine maintenance	Pole tops, overhead line and service line maintenance	Pole tops and overhead lines
Demand management opex/capex trade-off	No	Network overheads	SCS network overheads	SCS other
Insurance premiums	Yes	Non-network	Other	Other expenditure
New tariffs	No	Network overheads	SCS network overheads	SCS network management

1.1 IMPORTANT NOTE – REGULATORY INFORMATION NOTICE STEP CHANGE

3. JEN proposes that a further step change—not included in the opex forecast in this regulatory proposal—will be necessary to implement changes necessary to enable JEN to report "actual information" across the annual, benchmarking and category analysis Regulatory Information Notices (**RIN**). This would reflect a material change in JEN's regulatory obligations.

4. Costs for this activity will include training of staff, project management, changes to invoicing requirements with suppliers of good and services and other change management activities to transition the business to capture data in its accounting and records management systems for subsequent reporting in a form that will enable JEN to report this information as actual information in relevant RIN responses.

5. Until recently, JEN understood that the AER would make a regulatory information order[1] to supersede the current suite of RINs which would enable electricity distribution businesses to address compliance incrementally and to have a cost benefit based assessment of providing actual versus estimated data for elements of the RINs that require data which JEN does not record for the normal course of running its business.

[1] NEL, Division 4

6. Recent communications with the AER[2] indicate this is not the case and therefore JEN will propose an additional step change to cover the estimated costs to be incurred in order to ensure JEN can comply with the RINs from regulatory year 2016. A high-level preliminary estimate is $2m. Due to the timing of this AER communication, JEN will make a fully substantiated step change proposal during the public consultation process.

2 E-mail from AER staff to Jemena staff (and others), 10 April 2015

2. ASSESSMENT FRAMEWORK

7. The National Electricity Rules' (**Rules,** or **NER**) opex criteria are set out in Box 2–1:

Box 2–1 Rule 6.5.6(c) Criteria governing opex

The AER must accept the forecast of required opex of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):

1. the efficient costs of achieving the operating expenditure objectives; and
2. the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3. a realistic expectation of the demand forecast and cost inputs required to achieve the capex and opex objectives.

8. We have proposed prudent and efficient step changes which are required to promote the opex objectives in the Rules. JEN has also taken into account the AER's expenditure assessment guideline when identifying and proposing opex step changes.

9. The step changes proposed by JEN are not reflected in its base year opex, and are not captured by the rate of change escalation applied to the opex forecasts prepared using the base, step and trend method.

10. We have previously briefed AER staff on potential JEN step changes. Since those briefings we have further assessed our approach to identifying opex step changes.

11. JEN also notes that the final Regulatory Information Notice (**RIN**) requests additional information relevant to proposed step changes. Our RIN response cross-references to this appendix to minimise duplication and streamline the AER's assessment process.

3. SERVICE INSPECTION & TESTING PROGRAM

3.1 DRIVER

12. There is one network maintenance sub-program—JEN's service inspection and testing program—for which we must propose an opex step change to ensure we have sufficient funding to promote the opex objectives under the Rules.

13. This is a particularly significant operating sub-program that, when undertaken, represents over 30% of our expenditure on condition-based maintenance.

14. The following factors drive this step change proposal:

- JEN must undertake inspection and testing of service lines in accordance with regulatory obligations
  - JEN also needs to undertake this inspection and testing program (regardless of the regulatory obligation) because increases in electric shocks and tingles in recent years require additional management of a potential network safety issue.
- this activity was not undertaken in the base year (CY14) – the compliance obligation only requires JEN to undertake testing at least one every 10 years (but noting that not the program takes multiple years to carry out)
- trending forward the base year level of expenditure on this activity would underfund JEN for undertaking this necessary and significant condition-based maintenance program, which is required to meet its regulatory obligations.

3.2 JEN MUST INSPECT AND TEST SERVICE LINES

15. JEN must comply with its safety management system.[3] The safety management system requires JEN to manage its assets in accordance with their relevant asset lifecycle strategies (all of which JEN has included as part of its RIN response).

16. The low-voltage overhead services asset strategy requires—based on previous JEN safety assessments—that all overhead services have a "neutral to earth" resistance of less than 1 ohm that is verified at least one every 10 years.

17. It is not acceptable for JEN to breach its regulatory compliance obligations by not managing its assets in accordance with the approved safety management scheme and relevant asset class strategy.

18. As a consequence, JEN will need to perform routine neutral impedance testing of all services between 2016 and 2020, as well as visual inspection and ground clearance measurement of overhead services, in a well-structured program that is designed to maximise efficiency, and to provide a robust and sustainable basis for ongoing inspections in subsequent regulatory periods.

[3] Electricity Safety (Management) Regulations 2009, section 13.

3.3 OPEX STEP CHANGE FORECAST

19. Table 3–1 shows JEN's forecast opex step change for its service inspection and testing program over 2016-20.

Table 3–1: Service inspection and testing program step change forecast ($2015, millions)

	Step change forecast					
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Total step change	1.23	1.23	1.23	1.23	1.23	**6.15**

20. The forecasts are based on the numbers of services to be addressed multiplied by the actual rate of inspection per service of $23.80 ($2015) per service from the previous inspection program.

21. Table 3–2 shows that we intend to test 51,670 sites per annum, to ensure that all services are tested between 2016 and 2020.

Table 3–2: Forecast volumes – service inspection and testing program

Year	Number of Services
2016	51,670
2017	51,670
2018	51,670
2019	51,670
2020	51,670

22. Importantly, in forecasting the number of sites to be tested (51,670 p.a.), JEN has assumed that 40 per cent of non-preferred services will replaced as part of the service rectification program, and therefore will not require testing in the 2016-20 period. Therefore, these sites have been excluded from the volume forecast.

23. At the completion of the testing program, JEN will have complied with its regulatory obligation to test all service lines within a 10 year cycle.

4. OVERHEAD SWITCH INSPECTION

4.1 DRIVER

24. The drivers of this step change are:

- the deteriorating age profile of air break switches on the network
- an efficient opex for capex trade-off:
  - a large scale visual inspection program (opex) to inform a future targeted and efficient repair/replacement program (deferring capex where appropriate), in preference to a mass planned replacement program (capex)
- JEN's commitment to maintain reliability of the network, in accordance with customers' stated preferences
  - see chapter 5 of our regulatory proposal that sets out our customer engagement program ('what we heard')

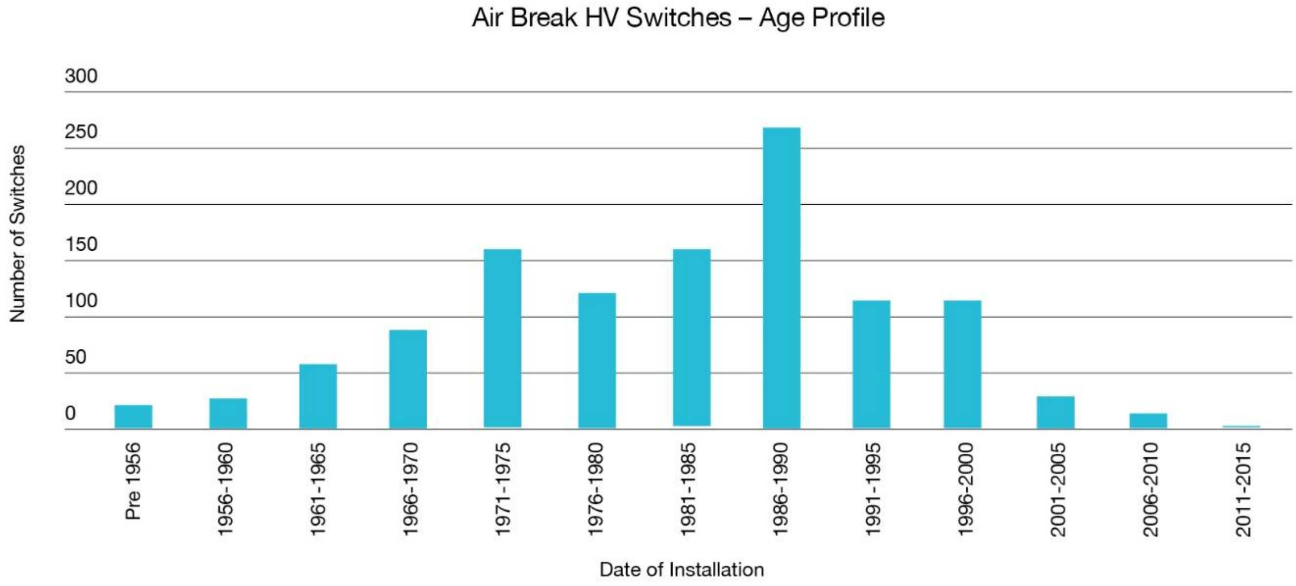
25. This proposal should be read in conjunction with the overhead line switchgear asset class strategy submitted as part of the EDPR RIN response. This is a new program and has not been incurred in JEN's CY14 base year, or any other element of JEN's expenditure forecasts.

4.2 MANAGING AN AGEING FLEET OF AIR-BREAK SWITCHES

26. JEN utilises overhead line switchgear to allow for flexibility within the network under loading and fault conditions. Over the years, different switching technologies have been implemented within the network. These include air break switches, isolators, and more recently, gas-insulated switchgear. There are approximately 7,900 pole-mounted high-voltage switching devices on the JEN network. Overhead line switchgear is typically a run to failure type asset.

27. Currently, JEN has around 1,000 air break switches installed and in-service. As set out in Figure 4–1, air break switches were largely installed on the JEN network prior to 2000, and the majority in the 1970s and 1980s. As such, air break switches tend to be 20 years old or more, and increasingly reaching end of life. More intensive asset monitoring is required.

Figure 4–1: Air break HV switches – age profile



28. JEN's has historically undertaken largely reactive maintenance for the air break switch asset class. Where significant component replacement or repair is required, the air break switch is replaced with a gas switch (the preferred asset type).

29. The status quo approach to managing these assets involves running the ageing assets to failure and replacing them reactively.

30. However an increasing number of these assets are expected to fail given the asset life profile. The status quo will compromise network reliability for our customers, against their stated preferences (refer chapter 5 of the regulatory proposal). Health and safety risks will rise because electrical network operators and the general public move in close proximity to these switches. Replacing failed switches under fault conditions is relatively costly.

31. It is good practice for JEN to transition to a structured planned replacement program for this asset type. JEN has two options (each with two sub-options) for a transition path to this future replacement program, which all involve a step change in opex.

32. Further information on our approach can be found in the relevant asset class strategy included with the RIN response.

4.3 OPTION 1: VISUAL CHECK OF ALL AIR BREAK SWITCHES

4.3.1 SUB-OPTION A: UNDERTAKE OVER 10 YEARS

33. This option is to run a cyclic 10 year visual check of all 1,068 air break switches on the network, identifying switches to be either repaired or replaced. JEN estimates that this will cost $117k per year over the 10 years.

34. The principal advantage of this option is it is relatively low cost in each year.

35. The principal disadvantage of this approach is the time period allows for newly forming defects to worsen to potentially dangerous levels between inspections. As the lifespan for an overhead air-break switch is 35 years,

a 10 year gap in inspections creates a material risk of large percentage of the population reaching end of life condition in the interim. There are higher costs associated with replacing failed switches under fault conditions, than under planned maintenance (as noted above).

36. We are also concerned that this approach does not adequately address the increasing risk to security of supply for our customers. It would not support JEN's ability to maintain existing network reliability in accordance with customers' stated preferences.

37. An additional disadvantage is that a visual inspection only will not detect defects such as bent contacts, seized pivots, weakened operating handles, and rusted contacts.

38. Due to the risk of health and safety impacts on JEN personnel and the general public, reduction of security of supply for customers and increased costs of replacing failed switches under fault conditions, this option is not preferred.

4.3.2 SUB-OPTION B: UNDERTAKE OVER 5 YEARS

39. This option is to run a cyclic five year visual and functional inspection of all 1,068 air break switches on the network, identifying switches to be either repaired or replaced. JEN estimates that this will cost $234k per year over the five years.

40. The benefit of this option is that it will allow the worst condition switches to be identified and maintained. This allows the most efficient opex and capex spend. The time period allows for new forming defects to be discovered before they significantly reduce the capabilities of the switch, potentially leading to failure.

41. The disadvantage is that, like with sub-option A, a visual inspection only will not detect defects such as bent contacts, seized pivots, weakened operating handles, and rusted contacts. As these defects pose significant risk to network operators and the general public, it would be prudent for any inspection program to check these defects. On this basis this option is not preferred.

4.4 OPTION 2: FUNCTIONAL AND VISUAL CHECK OF ALL AIR BREAK SWITCHES

4.4.1 SUB-OPTION A: UNDERTAKE OVER 10 YEARS

42. This option is to run a cyclic 10 year visual and functional inspection of all 1,068 air break switches on the network, identifying switches to be either repaired or replaced. JEN estimates that this will cost $210k per year over the 10 years.

43. The main benefit of this option is that it increases the likelihood of faults being detected before failure occurs, compared with status quo.

44. The main disadvantage is that a 10 year period allows for newly forming defects to worsen to potentially dangerous levels between inspections. A 10 year gap in inspections would result in a larger percentage of the population reaching end of life condition in the interim.

45. Due to the high risk of health and safety impacts on JEN personnel and the general public, reduction of security of supply for customers, increased costs of replacing failed switches under fault conditions and the inability to maintain existing network reliability, this option is not preferred.

4.4.2 SUB-OPTION B: 5 YEAR FUNCTIONAL AND VISUAL AIR BREAK SWITCH CHECK

46. This option is to run a cyclic five year visual and functional inspection of all 1,068 air break switches on the network, identifying switches to be either repaired or replaced. JEN estimates that this will cost $420k per year over the five years.

47. The benefits of this option are:

- it allows efficient identification and prioritisation of repair and maintenance works on those switches that are in the worst condition. This allows the most efficient opex and capex spend.
- the time period allows for newly forming defects to be discovered before they significantly reduce the capabilities of the switch, potentially leading to failure.
- functional testing will identify defects such as bent contacts, seized pivots, weakened operating handles, and rusted contacts that will only be discovered during operation of the switches.
- functional testing will give a more accurate view of the condition of the air break switches and will also reveal defects to enable JEN to maintain/improve reliability and safety of its network.

48. Given these benefits, option 2B is the preferred option.

4.5 SUBSTANTIATION OF FORECAST COSTS

49. The overhead switch inspection program is designed to identify defects with overhead switches, so that JEN can develop a more informed repair or capital replacement program.

50. JEN's forecast opex step change includes an estimate of the cost to complete a visual inspection and functional test in accordance with option 2B.

51. The visual inspection requires Elevated Work Platform (**EWP**) access to the switch. The functional test involves bypassing the electrical switch mechanism and operating the switch. As the electrical mechanism is bypassed through hoppering or tying back connections, no network interruption is required.

52. The inspection and testing of each switch is closed out once the reporting requirements have been fulfilled. Photographs are taken and nameplate details recorded.

53. JEN estimated the forecast opex step change for the visual inspection and functional test by multiplying an estimated unit rate for visual inspection and functional inspection against the current overhead air break and isolator switch population (1,068). It is also prudent to take the opportunity to inspect the pole-top structure.

Table 4–1: Overhead air break switch inspection unit rates ($2014, $dollars)

	Rate	Qty	Total
Labour	$82.58/hr	12	$991
Materials	$808	1	$808
Fleet	$104	1	$104
Stores recovery	$65	1	$65
Total	**N/A**	**N/A**	**$1,987**

54. A population of 1,068 to inspect over five years, at a unit rate of $1,987 ($2014) per switch, requires funding of $2.1M over five years ($2015, $millions). We intend to inspect similar numbers over the five years so have allocated this cost equally over the five years.

Table 4–2: Overhead air break switch inspection step change forecast ($2015, millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	0.43	0.43	0.43	0.43	0.43	**2.17**

5. ENCLOSED SUBSTATION INSPECTION AND RECTIFICATION

5.1 DRIVER

55. This step change is driven by a change in regulatory obligations. Section 7 of the Electricity Safety (Bushfire Mitigation) Regulations 2013 commenced on 20 June 2013, and requires:

> *(1) a plan for inspection that ensures that—*
>
> > *(i) the parts of the major electricity company's supply network in hazardous bushfire risk areas are inspected at intervals not exceeding 37 months from the date of the previous inspection; and*
> >
> > *(ii) the parts of the major electricity company's supply network in other areas are inspected at specified intervals not exceeding 61 months from the date of the previous inspection.*
>
> *(2) In subregulation (1)(i) supply network does not include a terminal station, a zone substation or any part of the major electricity company's underground supply network that is below the surface of the land.*

56. JEN intends to undertake routine proactive inspection of enclosed distribution substations every 36 months in the Hazardous Bushfire Risk Area (**HBRA**) and every 48 months in the Low Bushfire Risk Area (**LBRA**). These intervals are slightly shorter than prescribed in the regulations to ensure that any missed substations do not instantly fall outside the required period. This is considered to be a prudent approach.

5.2 OPEX STEP CHANGE FORECAST

57. To meet this obligation we will need to inspect 550 sites per annum on an ongoing basis

58. Due to the timing for the introduction of this new obligation, and requirements to schedule and resource the program, only 100 substations were inspected in CY14. The cost estimated to be incurred in the CY14 base year ($12K) is therefore not representative of required annual opex for 2016-20. We have removed this base year amount from this opex step change proposal to ensure no double-counting.

59. The key assumption in developing the opex step change forecast is the unit rate for inspection and rectification. We have adopted a reasonable unit rate assumption by utilising unit rates incurred in a previous and comparable inspection program:

- for inspections: $120 per site
- for rectifications: $440 per site requiring work, with an assumption of 50% of sites requiring some form of (likely minor) rectification work.

Table 5–1: Enclosed substation inspection program step change forecast ($2015, millions)

	Step change forecast					
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Inspection program to meet new obligation	0.068	0.068	0.068	0.068	0.068	**0.341**
Rectification of defects	0.125	0.125	0.125	0.125	0.125	**0.626**
Less CY14 unrepresentative expenditure	*0.037*	*0.038*	*0.039*	*0.040*	*0.041*	***0.193***
Total step change	**0.157**	**0.156**	**0.155**	**0.154**	**0.153**	**0.774**

6. ELECTRICITY DISTRIBUTION PRICE REVIEW

6.1 DRIVER

60. The driver of this step change is the non-representative level of EDPR costs incurred in the CY14 base year, and the materiality of the required adjustment to ensure forecast 2016-20 opex promotes the opex objectives under the Rules.

61. If JEN did not propose this combined adjustment (base year adjustment and step change), our customers would be paying too much for our services, which would not promote the National Electricity Objective (**NEO**). This is because would be trending forward an unrepresentatively high amount of annual opex for the 2021-25 JEN price review, based on CY14 actual EDPR opex. This is not in customers' long-term interests.

6.2 IMPACTED OPEX ACTIVITIES

62. The next regulatory period will commence on 1 January 2016, and is expected to end on 31 December 2020. The subsequent regulatory period would commence on 1 January 2021.

63. Under clause 6.8.2 of the NER, JEN must prepare and submit to the AER a regulatory proposal which contains detailed information on the services, costs and prices it proposes for the forthcoming regulatory control period.

64. The 2021-26 regulatory proposal will be lodged with the AER around early 2020. This step change takes into account the preparation of this 2021-26 regulatory proposal.

6.3 OPEX STEP CHANGE FORECAST

65. The step change forecast is based on actual and forecast incremental costs for preparing the current 2016-20 EDPR submission. JEN considers that this is a conservative estimate as regulatory requirements for EDPRs tend to increase substantially from review to review. The forecast cost for the EDPR has been developed:

- for CY15 and CY16: budgeted costs for EDPR preparations
- for CY19: actual costs for CY14 (CY14 is the equivalent year to CY19 in that preparations for the EDPR commenced in that year)
- for CY20: cost forecasts for CY15 (CY15 is the equivalent year to CY20 in that the regulatory proposal will be submitted, and work to respond to the draft determination will commence)

66. The above methodology is consistent with the approach adopted for JGN as part of the 2015-20 Access Arrangement, which was approved by the AER in the draft decision[4].

67. Regulatory proposal costs incurred in CY14 have been removed from CY14 base year opex to ensure no double-counting.

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

[4] AER, *Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015-20, Attachment 7 Operating expenditure*, November 2014, p 7-22

- 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.

Table 6–1: EDPR 2021-25 project step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	1.20	-	-	3.00	3.84	**8.03**

7. VEGETATION MANAGEMENT

7.1 DRIVER

69. The driver of this step change is a change in JEN's regulatory obligations, specifically:

- the Electricity Safety (Electric Line Clearance) Regulations 2015 under the Electricity Safety Act 1998 are expected to come into force by 30 June 2015 (**2015 regulations**)
- the Electricity Safety Amendment (Bushfire Mitigation) Act 2014 proclaimed on 25 March 2014, with the exception of section 12(2) which came into operation on 1 April 2014[5] (**2014 Act**)
  - therefore, there was an unrepresentatively low cost incurred to meet these obligations in the CY14 base year.

7.1.1 2015 REGULATIONS

70. There are three drivers for increased opex arising from changes in regulatory obligations outlined in the exposure draft of the Electricity Safety (Electric Line Clearance) Regulations 2015. They are:

1. adoption of amenity tree management standard AS 4373

71. JEN will need to adopt amenity tree management standard AS 4373 to comply with the proposed Regulations. The standard provides guidance on the means of carrying out required pruning while maintaining the health and natural appearance of the tree as far as possible, thus delivering standardised amenity outcomes.

2. enhanced notification and consultation provisions

72. Proposed enhanced notification and consultation provisions will require JEN to write to affected persons notifying them of intended pruning or tree removal. This notification will provide more detailed information than in the past, includes a new requirement to publish notices in a generally circulating newspaper, and additional details of arrangements for dispute resolution.

3. assistance which must be provided to Councils

73. Proposed changes require JEN to assist, if requested, a Council that has concerns about the safety of cutting or removal of a tree for which the Council has clearance responsibilities, or concerns about determining the allowance for cable sag and sway, to:

- ensure the cutting or removal of the tree can be undertaken safely
- set safe limits of approach to electric lines for cutting/removing the tree
- establish safe methods for cutting/removing the tree
- determine the additional distance by which the minimum clearance space must be extended to allow for sag and sway of cable spans exceeding 100 metres.

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5 Victoria Government Gazette SG 94 25/03/2014 p.1

7.1.2 2014 ACT

74. A fourth opex step change is driven by the Electricity Safety Amendment (Bushfire Mitigation) Act 2014 affecting designated responsible persons. JEN now must undertake electric line clearance vegetation management of areas that were previously managed by other responsible persons (including Roads Corporation, Vic Roads, Vic Track, Vic Rail and statutory water bodies).

75. The new section 84 provides that a distribution company is responsible for keeping a tree clear of an electric line within its distribution area unless another person under Subdivision 1 is responsible for maintaining the electric line or keeping the tree clear of the electric line.

7.2 IMPACTED OPEX ACTIVITIES

76. As new obligations, JEN is proposing an increase to the existing regulatory allowance for vegetation management to enable this program to confirm with new legislative requirements.

77. Adopting the uniform tree pruning procedures and practices defined in amenity tree management standard AS 4373 and its associated guidelines will allow JEN to meet its regulatory obligations. JEN already complies with this standard in-as-far as "cutting" is specified, e.g. when removing a branch, the position of the final cut should be a clean cut to the branch collar or, in the absence of a collar, to a position determined by the branch bark ridge.

78. In a small number of cases JEN may need to employ the use of climbing spikes. To meet the requirements of AS 4373, spikes may only be used on the parts of a tree not being retained. Therefore an EPV and traffic management will need to be used in these climbing cases.

79. Enhanced notification and consultation provisions will require JEN as the Responsible Person to notify intended cutting or removal to all affected persons both in writing and by publication in a newspaper circulating generally to the locality. The proposed form of the notice will require JEN to detail, among other things, the dispute resolution mechanisms, images, sketches and individual impact statements.

80. JEN is now responsible for additional tree clearing that was previously the responsibility of a public land manager (e.g. Vic Roads) in its distribution area.

81. Assisting councils with vegetation trimming / removal and ensuring that this work is done safely will require ongoing audit of council vegetation management practice.

7.3 BASIS OF THE COST FORECAST

7.3.1 ADOPTION OF AMENITY TREE MANAGEMENT STANDARD AS 4373

82. We have adopted a volume and unit-rate driven forecasting method. We estimated 50 cases requiring climbing per annum. The estimated cost per case includes $2,000 for use of an elevated work platform and $1,500 per case for traffic management. This results in a total cost of $0.175M per annum ($2014).

7.3.2 ENHANCED NOTIFICATION AND CONSULTATION PROVISIONS

83. Due to the significant additional requirement for each notice to contain images, sketches and individual impact statements, we forecast a requirement for an additional three assessors (and associated vehicle and equipment to process notices on site). Our total cost forecast is $0.595M per annum ($2014), comprising:

- cost of new assessors: 3 FTEs at $0.15M per annum (total cost $0.45M p.a.) ($2014)
- half an FTE to manage new enquiries: 0.5 FTE at $0.15M (total cost $0.75M p.a.) ($2014)
- equipment and equipment maintenance for existing 7 assessors: $0.07K p.a. ($2014).

7.3.3 ASSISTANCE WHICH MUST BE PROVIDED TO COUNCILS

84. The only way that clause 19(2)(a) of the regulations can be satisfied cost-effectively is for JEN to provide two full time auditors for all council work to be undertaken in the vicinity of the safe approach distance. JEN will also require 0.5 of an FTE to respond to enquiries relating to the setting of limits of approach, establishing safe work method statements (**SWMS**) for councils and calculating sag and sway. We expect that the 0.5 FTE required to address new enquiries (refer previous section) should be able to meet this new activity.

- 2 FTEs for auditing council work and managing enquiries: 2 FTEs at $0.150M (total cost $0.3M)

7.3.4 REMOVAL OF ROADS CORPORATION AS A RESPONSIBLE PERSON

85. We have completed an assessment of the areas affected by the regulatory change. JEN is responsible for approximately 565 additional spans.

86. As of 1 April 2014, JEN has been responsible for maintaining electric line clearance for these areas and vegetation management activities have already commenced. However, expenditure in the balance of CY14 (i.e. April 2014 to December 2014) does not represent a full representative year of expenditure.

87. Ongoing vegetation maintenance requires an incremental $0.09M in CY16 to bring us to a compliant state relative to CY14 expenditure.

7.4 OPEX STEP CHANGE FORECAST

Table 7–1: Vegetation management step change forecast ($2015, millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Amenity tree management standard AS 4373	0.18	0.18	0.18	0.18	0.18	**0.90**
Enhanced Notification and Consultation provisions	0.62	0.62	0.62	0.62	0.62	**3.08**
Assistance which must be provided to Councils	0.31	0.31	0.31	0.31	0.31	**1.55**
Removal of Roads Corporation as a Responsible Person	0.09	0.00	0.00	0.00	0.00	**0.09**
Total step change	**1.20**	**1.11**	**1.11**	**1.11**	**1.11**	**5.63**

8. ESV CODE OF PRACTICE CHANGES

8.1 BACKGROUND

88. The driver of this step change is an expected change in regulatory obligations.

89. JEN must comply with the Code of Practice for Electrical Safety[6] (**Blue Book**). The Blue Book applies to all persons working on, near or in the vicinity of high voltage electrical apparatus that is capable of being energised. Work health and safety law places duties on businesses and workers to ensure, so far as is *reasonably practicable*, the health and safety of workers and that of other persons are not put at risk from the work.

90. The Blue Book is maintained by the electrical safety committee (**ESC**) established under Section 8 of the Energy Safe Victoria Act 2005. The objective of the Committee is to review and further develop the Blue Book to facilitate the electrical safety of electrical generation, transmission and distribution systems and high voltage electrical installations.

91. The ESC completed the revision of the 2005 Blue Book in 2012 and republished by ESV in 2012. As noted in the Blue Book[7], the Blue Book:

> *is regularly reviewed to ensure that it reflects current work requirements and emerging technologies.*

92. Noting this review requirement, and that the Blue Book was last reviewed and revised three years ago, we expect the Blue Book to be reviewed at least once during the next regulatory period. We reasonably expect that this would result in changes to JEN's regulatory obligations regarding management of electricity safety systems. Based on the seven-year cycle (2005 to 2012) between initiation and first revision, we estimate review and implementation processes in 2018 and 2019.

93. Costs of implementing the outcomes from such a fundamental independent review of operational safety and management are not captured in base year opex (as no relevant activity was undertaken in CY14).

8.2 A REVIEW WILL DRIVE MATERIAL COSTS

94. The review process will likely be resource-intensive for revision, modification and education of our workforce.

95. As a result of this review, JEN will have to review and update the Electrical Safety Rules for the Victorian Distribution Networks (the Green Book) with the subsequent result being a review of all Jemena work procedures, manuals and work instructions. To put this in perspective, JEN has over 100 work procedures, directives, safe work method statements, safe work procedures, work instructions, no-go zones and policies and standards.

96. Specialist technical staff will need to be seconded onto a process review project to ensure ongoing compliance (and their positions back-filled) and if required, negotiate departures with ESV following detailed hazard assessments, as currently allowed under the Blue Book:

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[6] ESV, *Code of practice on electrical safety for work on or near high voltage electrical apparatus*, 2012. Found online at: http://www.esv.vic.gov.au/Portals/0/Legislation%20and%20Regulations/Files/PRINTED%20BLUE%20BOOK%20%202012%20.pdf

[7] See page i.

In order to comply with the electrical safety procedure requirements of this Code, an organisation shall either:

a. Apply the procedures contained within this Code; or

b. Vary the procedures by:

- *completing a hazard identification and risk assessment*
- *ensuring the electrical safety outcomes are equal to or better*
- *documenting the process*
- *advising Energy Safe Victoria in writing of outcomes and reasons for variation(s) prior to implementing the variation.*

8.3 OPEX STEP CHANGE FORECAST

Table 8–1: ESV code of practice changes step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	0.00	0.00	0.83	0.10	0.00	**0.93**

8.3.1 SUBSTANTIATION OF COSTS

97. Labour rates reflect specialist technical resourcing and leadership team involvement to approve changes to safe work procedures and management of ESV engagements as required. Changes to in-grained work practices will require careful and intensive training and change management to resolve issues and eliminate potential for misunderstandings that can result in non-compliance.

Opex activity	Rate ($2014, $dollars)	Resources	Total ($2014, $millions)
Phase 1: Blue Book implementation			
Review of over 100 work practices and manuals	$200/hr	3 FTEs, 90 days	$0.432M
Phase 2: Green Book development, education and training			
Green book review and development	$200/hr	1 FTE, 84 days	$0.1344M
Printing and distribution of revised manuals to field staff and contractors			$0.97M
Green Book awareness sessions for JEN staff and contractors	$200/hr	1 FTE, 67 days	$0.107M
Training and change management sessions (estimated to fall in 2019)	$5500/session	15 sessions	$0.0825
Total			**$0.901M**

9. VULNERABLE CUSTOMER INITIATIVE

9.1 DRIVER

98. JEN recognises that a number of our customers are struggling to pay rising electricity bills. Through engagement with, and research, into JEN's customer base, JEN has found that a significant number of its customers are likely to be particularly vulnerable to rising energy prices.

99. In addition:

- studies of JEN's customer demographic (based on Australian Bureau of Statistics 2011 Census data) show that a significant proportion (34%) of its customers have English as a second language
- national community welfare agency, Kildonan UnitingCare, has stated that up to 40% of JEN's demographic are likely to be technically illiterate and require more simplified information regarding energy related issues.

100. JEN engaged extensively with its customers and stakeholders about ways it could assist vulnerable customers, and this proposed expenditure reflects the feedback received as part of this process. Please refer to our regulatory proposal attachment regarding our customer, stakeholder and community engagement.

101. JEN has not undertaken these activities during its 2014 base year. JEN therefore proposes a step change to its opex in order to obtain funding to undertake these initiatives, consistent with customer feedback.

9.2 INITIATIVE IDENTIFICATION

102. JEN has developed a number of options to assist vulnerable customers. These options had a particular emphasis on addressing primary causes of energy hardship where possible, including improving customers' understanding of their energy usage (empowering them to make more informed (efficient) decisions about their energy usage).

103. JEN presented various options to four key engagement forums:

1. financial and energy counsellors (workshop)
2. socially disadvantaged customers (focus group)
3. 'mass market' customers (focus group and deliberative forum)
4. JEN's Customer Council.

104. Engagement with mass market customers and JEN's Customer Council involved clearly explaining the cost to all customers of the various assistance options.

105. After considering the feedback from our customers and stakeholders, JEN is proposing four initiatives outlined below.

9.2.1 IN-HOME-DISPLAY (IHD) TRIAL (FOR 500 CUSTOMERS)

106. JEN believes that a customer's understanding of how they use electricity is an important step towards managing their electricity bills, especially for customers who are particularly vulnerable to rising energy prices. Smart meters and tools such as our Electricity Outlook Portal enable customers to access detailed information about

how they use electricity. However, portals require access to the internet, and JEN recognises that a lack of Internet access presents a barrier to some vulnerable customers accessing this tool.

107. An IHD is a hand-held or wall-mounted device which communicates directly with a customer's smart meter, allowing the customer to see their energy usage in real time, without the need for a computer. JEN previously ran a trial where we gave in-home energy displays to 50 key stakeholders, and received positive feedback about how the devices allowed participants to better manage their energy usage.

108. JEN would run a similar trial where we would provide in-home energy displays to groups of vulnerable customers. JEN would partner with local Government and/or community groups to deliver this program (for 500 customers), as those organisations are better placed to identify vulnerable customers and distribute the devices, along with providing appropriate guidance on how to use them. JEN would also assist with workshops to teach the customers how to use the devices, and provide train-the trainer guidance for our partner organisations, if JEN was to provide in-home energy displays to a small group of customers.

9.2.2 NO INTEREST LOAN SCHEME (NILS) FUNDING

109. Often, customers may be particularly vulnerable to rising energy prices as they may be unable to reduce the amount of energy they use where they can't afford to upgrade older, less efficient appliances (such as fridges). JEN would provide some funding to a community or microfinance organisation which provides no- or low-interest loans to vulnerable customers, enabling them to purchase new, more energy efficient appliances, reducing their electricity usage (and bills) accordingly.

9.2.3 IMPROVED COMMUNICATIONS FOR CULTURALLY AND LINGUISTICALLY DIVERSE (CALD) CUSTOMERS

110. JEN knows that the cultural and linguistic diversity of its customer base is increasing, and that people who are new to Australia may find it difficult to successfully navigate energy markets and may also encounter other factors which can contribute to hardship (such as housing and parenting costs and commitments, as well as low income). JEN is currently developing some pilot low-literacy communications material which covers energy safety issues.

111. In the future, JEN would develop additional focus-group tested energy literacy (as well as energy safety and outage) material, partner with community groups and target local media advertisements to customers who have low levels of English to help raise energy literacy levels of CALD customers. The average annual cost per customer of doing this would be between $0.15 and $0.25.

9.2.4 COMMUNITY PARTNERSHIPS

112. JEN currently does this with some organisations, and would partner with more local welfare agencies and develop energy literacy material to help vulnerable community groups better understand energy efficiency and costs. The average annual cost per customer of doing this would be between $0.05 and $0.15.

9.3 OPEX STEP CHANGE FORECAST

Table 9–1: Assisting vulnerable customers step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
IHD trial	0.03	0.0	0.0	0.0	0.0	**0.03**

	Step change forecast					
NILS	0.08	0.08	0.08	0.08	0.08	**0.41**
CALD communications	0.07	0.07	0.07	0.07	0.07	**0.36**
Community Partnerships	0.04	0.04	0.04	0.04	0.04	**0.21**
Total step change	0.22	0.20	0.20	0.20	0.20	**1.01**

113. The annual forecast cost of the NILS initiative is an estimate based on the provision of $1 million of funding to a no-interest loan scheme provider for 2016 to 2020, where JEN receives full repayment of the $1 million at the end of the period. JEN therefore incurs funding cost on the $1 million, assumed to be 8% per annum.

10. CUSTOMER ENGAGEMENT

10.1 DRIVER

114. Changes to the Rules made during JEN's current regulatory control period place a new requirement on distribution businesses to engage with their customers. 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.

115. JEN is committed to engaging with our customers, stakeholders and the broader community, in order to strive to understand and balance the expectations of customers, stakeholders and the broader community in our decision making. Effective engagement is critical for JEN to be able to ensure that the services it provides and prices it charges are in the long-term interests of customers.

116. Additionally, the AER's Consumer Engagement Guideline, while not binding on JEN, outlines the AER's expectations around customer engagement, with respect to best practice principles and the design and delivery of customer engagement activities.

117. Furthermore, JEN needs to expand its business-as-usual (ongoing) customer engagement activities by building on positive feedback received following activities undertaken during CY14. JEN must continue to create opportunities to receive a broad range of customer feedback and incorporate it into its decision making.

118. During 2014, JEN has incurred costs in order to satisfy these consumer engagement requirements and good industry practices. These have been costed against the EDPR project, and so have been removed from the base year (as noted in section 6). Consequently, there are <u>no</u> customer engagement costs in the CY14 adjusted base year.

119. JEN will continue to incur costs in undertaking these customer engagement activities throughout the 2016-20 EDPR period. JEN must therefore propose a step change to its opex in order to obtain funding for these activities for the next regulatory period.

120. Regulatory consequences of not undertaking appropriate customer engagement include:

- if JEN does not effectively engage with its customers, it will be unable to make a submission to the AER under Rules cl. 6.8.2(c1)(2) for its 2021-25 EDPR which adequately describes how it has sought to address relevant concerns identified as a result of its customer engagement
- if JEN does not effectively engage with its customers, it risks unfavourable regulatory decisions in relation to its approved expenditure (due to the AER needing comply with Rules cl. 6.5.6(e)(5A) and 6.5.7(e)(5A)).

121. If JEN does not meet accepted, good industry practice, its credibility and reputation with its customers and other stakeholders would also be damaged.

122. Additionally, this step change includes the expenditure required for JEN to meet its obligation[8] under the Electricity Distribution Code relating to the distribution of a Customer Charter to each customer at least once every five years, and to new connections and re-energisations which occur between mass mail-out exercises.

123. The costs of the design, printing and mass mail-out of a Customer Charter to each customer which must be incurred by JEN in order to comply with this obligation are not reflected in the CY14 base year, as the previous

[8] Electricity Distribution Code, section 9.1.2

mass mail-out occurred during CY11. As JEN is required to perform a mass mail-out all customers once every five years, and the previous mass mail-out was undertaken in CY11, JEN must undertake the next mass mail-out prior to the end of CY16.

124. If JEN does not undertake the mass mail-out of a Customer Charter to all customers by the end of CY16 or does not distribute a Customer Charter to each new connection and re-energisation which occurs during the next regulatory period, it will not have complied with section 9.1.2 of the Electricity Distribution Code. JEN must comply with the Electricity Distribution Code under its distribution licence.

10.2 IMPACTED OPEX ACTIVITIES

125. There are material ongoing costs associated with meeting the level of customer engagement reflected in the AER's Consumer Engagement Guideline.

126. Based on the drivers above, and the feedback from customers and stakeholders involved in JEN's engagement activities during CY14, JEN considers it is appropriate to carry forward a similar mix of engagement activities over the next regulatory period, as set out in the table below.

Table 10–1: Proposed customer engagement activities

Activity	Proposed frequency for 2016-20
Jemena Electricity Customer Council	4 meetings per year
Large customer/major stakeholder forum	1 per year
Deliberative forum/mass market customer research	1 per year

127. The customer engagement activities outlined in the table above are proposed to be undertaken in each year of the next regulatory period. However, activities undertaken during CY19 are captured under the EDPR project step change (refer to section 6), and their costs have therefore not been included in this step change.

128. The expenditure proposed to meet JEN's requirements under the Electricity Distribution Code in relation to the Customer Charter reflect the cost of designing, printing and mailing a Customer Charter document to every customer connected to JEN's network as at the time the mail-out is performed, in addition to the cost of printing copies of the Customer Charter for each new connection and re-energisation which occurs after this time for the remainder of the regulatory period.

129. As explained in section 10.1, the Customer Charter costs are not reflected in JEN's base year opex due to a misalignment between the five year cycle at which Customer Charters are required to be distributed and the timing of JEN's base year.

10.3 PRUDENCE ASSESSMENT

130. There are material ongoing costs associated with undertaking this level of engagement.

131. As part of its customer engagement activities for its 2016-20 EDPR, JEN has prioritised engagement with key stakeholder groups and designed forums around these groups to ensure that engagement is targeted and relevant to different customers' and stakeholders' concerns, interests and knowledge levels. Customer and stakeholder groups engaged with during CY14 include:

- energy and financial counsellors (workshop)

- vulnerable customers (focus group)
- large customers (major stakeholder forum and individual meetings)
- retailers (pricing workshop)
- a broadly representative group of residential and small and medium business customers ('mass market customers') (focus group and deliberative forum).

132. JEN has also continued to engage with its quarterly Customer Council throughout 2014. JEN undertook a review of the operation and strategic direction of its Customer Council in the second half of 2013, and identified several initiatives to strengthen its operation, including the payment of sitting fees to members representing not-for-profit organisations, in line with current practice by similar energy and water utilities. The Customer Council's membership now includes a broader range of customer representatives and other stakeholders, including consumer advocates, vulnerable customer groups, ombudsmen, large customers and representative groups, technology advocates and regional development groups.

133. Evaluation surveys and other informal feedback gathering after each engagement activity, as well as discussion with the Jemena Electricity Customer Council in March 2015 and a survey of a range of customers and stakeholders JEN engaged with, conclude that JEN's customers and stakeholders:

- valued JEN's commitment to engaging with them
- were generally satisfied with the way JEN had engaged with them, considering JEN as having:
  - engaged genuinely and meaningfully with them
  - addressed issues of interest to them
  - listened to their questions, views and experiences
- strongly supported JEN continuing to engage with its customers and stakeholders on an ongoing basis
- considered JEN should do more to engage with a larger number of its mass-market customers, further improving accessibility for interested customers and stakeholders.

134. Further detail about stakeholders' views on the effectiveness of JEN's engagement activities undertaken is contained in section 6 of Attachment 4–1.

135. The forecast costs of the Jemena Electricity Customer Council, large customer/major stakeholder engagement forums and mass market engagement and research reflect the actual costs incurred by JEN in undertaking this customer and stakeholder engagement during CY14.

136. Based on feedback from customers and stakeholders, JEN considers that expenditure similar to that of CY14 represents a prudent and efficient level of engagement. Over the next regulatory period, this expenditure will allow JEN to respond to stakeholders' views that it should engage with a larger number of mass-market customers. Additionally, as JEN continues to build a better understanding of its mass-market customers and their interests and requirements, it may be able to employ new ways of engaging with them, including potentially more web-based research.

137. The forecast cost of producing and distributing a Customer Charter is based on the actual costs incurred by JEN to design and print a Customer Charter and undertake a mass mail-out to all customers in CY11 and an estimate of the cost of printing Customer Charters to be distributed to new connections and re-energisations which occur after the mass mail-out.

10.4 OPEX STEP CHANGE FORECAST

Table 10–2: 2016-20 customer engagement step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Jemena Electricity Customer Council	0.01	0.01	0.01	0.00	0.01	0.04
Large customer/major stakeholder forums	0.01	0.01	0.01	0.00	0.01	0.04
Mass market engagement and research	0.11	0.11	0.11	0.00	0.11	0.44
Customer Charter production and distribution	0.39	0.00	0.00	0.00	0.00	0.38
Total step change	**0.52**	**0.13**	**0.13**	**0.00**	**0.13**	**0.93**

11. NEW TECHNOLOGY TRIAL: POLE-TOP FIRE DETECTION

11.1 POLE TOP EARLY DETECTION SYSTEM TRIAL

138. Pole top fires start as low partial discharges and detection of early partial discharges can help in reducing the risk of pole top fire starts.

139. An early fire detection (**EFD**) system has the capability to detect low levels of partial discharges on pole top structures. If proved to be successful, the long-term benefits would be reduced risk of pole fire incidents as well as a potential reduced need for pole top fire mitigation expenditure to maintain fire safety levels on the network.

140. JEN is proposing an opex program to deploy a limited number of pole top fire detection systems over the 2016 regulatory period. Such an initiative is not reflected in CY14 base year activities or expenditure.

141. The program will include leasing a pole-top EFD system in 2016 and testing the system on a number of feeders. This will include relocating the systems annually in order to cover more feeders during the period. Deployment and testing of the technology on various feeders is necessary before a decision on the benefits of potentially rolling out this new technology as a permanent solution could be made.

142. The step change will increase maintenance expenditure on SCADA/Network Control.

11.2 OPEX STEP CHANGE FORECAST

Table 11–1: Pole top fire early detection system trial step change forecast ($2015, millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	0.28	0.28	0.28	0.28	0.28	**1.38**

143. As this project is unprecedented, the costs over the 2016 regulatory period are estimated based upon quotations from the supplier as well as estimates based on similar pole-top installations.

11.2.1 SUBSTANTIATION OF COSTS

144. The cost estimate in support of this proposal has been generated from:

- the cost of leasing an EFD system (supplier quote)
- project delivery cost to install an EFD system on feeder BY11. The estimate of delivery work is based upon similar works from previous projects such as fault indicator installation.

145. The cost of leasing, installing and trialling a pole-top fire detection system from IND Technology for a period 12 months is estimated to be $0.27M ($2014).

12. DEMAND MANAGEMENT OPEX FOR CAPEX TRADE-OFF

12.1 DRIVER

146. The drivers of this step change are opportunities for prudent and efficient opex for capex trade-offs. Not undertaking these opex activities will increase JEN's capex requirements as described below.

12.2 BACKGROUND

147. This step change is for operating costs associated with two specific demand response (**DR**) opex programs to mitigate two network constraints and limit potential risk of supply interruption to customers, which would otherwise need to be addressed through a capex response. The areas are:

- Footscray East (**FE**)
- North Heidelberg and Watsonia (**NH-WT**)

148. The long-term solutions for these constraints require network augmentation works. However, by deploying DR programs, network augmentation works can be prudently deferred to the 2021-25 regulatory period. JEN must plan a targeted DR program for the two constrained areas.

149. Both DR programs will have two phases:

- phase 1 includes planning, customer acquisition, technology deployment and testing and commissioning
- phase 2 includes ongoing operations, customer management, financial settlement and documentation and reporting.

12.3 OPTIONS ANALYSIS

12.3.1 OPTION 1 – NETWORK AUGMENTATION (CAPEX)

150. The estimated cost of the capex solutions are $9M (for FE) and $11M (for NH-WT). These estimates are desktop estimates based on projects of similar scale.

12.3.2 OPTION 2 – TARGETED DEMAND RESPONSE PROGRAM

151. A targeted DR program will consist of individual DR projects. Each project will be designed to reduce network risk over the life of the project in the most economically prudent manner.

152. By deploying this DR program:

- a portion of the risk of supply interruption and corresponding cost of expected unserved energy will be transferred from JEN's customers to participants of JEN's DR programs
- related network augmentation works can be deferred to the 2021-25 regulatory period.

153. Adopting a discount rate of 7.0%, and annual straight-line depreciation rate of 2% (based on a 50-year asset life), we estimate the deferred capex (per annum) as:

- For FE: $9M x (0.07 + 0.02) = $0.81M ($2014)
- For NH-WT: $11M x (0.07 + 0.02) = $0.99M ($2014).

154. The costs of the DR program are estimated based upon preliminary discussions with DR aggregators. The cost of each targeted DR project reflects length of the program, number of customers enrolled and the technical characteristics of expected demand response.

155. Cost estimates for JEN DR programs are set out in the table below. As can be seen, the cost of the DR programs justify deferring the capex. For example, there are $0.81M in benefits from deferring from FE capex, at a cost of just [c-i-c]. While the DR solution is not as firm as the capex solution, this significant cost differential justifies the risk allocation.

Table 12–1: Project Benefits and Costs

Project	Project Period	Reduction in Cost of Expected Unserved Energy – A$,000	Estimated Total Project Cost – 2014 A$	Estimated Project Cost in 2016-20 Period – 2014 A$	Estimated Project Cost in 2016-20 Period p.a. – 2014 A$
DR in Footscray East	2016 – 2021	634,005	[c-i-c]		
DR in North Heidelberg and Watsonia	2017 - 2022	252,683			

12.4 OPEX STEP CHANGE FORECAST

Table 12–2: 2016-20 step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	0.11	0.15	0.15	0.15	0.15	**0.71**

156. This additional opex cost is not reflected in JEN's base year cost (CY14), hence an opex step change is required to fund the DR programs in 2016-20.

[c-i-c]

[c-i-c]

[c-i-c]

[c-i-c]

14. NEW TARIFFS

14.1 DRIVER

183. The primary driver for this step change is a change in JEN's regulatory obligations.

184. On 27 November 2014, the AEMC made a rule that introduced new pricing arrangements to the NER. The intent of the rule change is to drive cost-reflective network prices and improve the transparency of distributors pricing information. This has created new obligations on distribution businesses, including:

- preparing a tariff structures statement (**TSS**) with a regulatory proposal and revised regulatory proposal and provide an explanation as to how the TSS meets the pricing principles[11]
- including in the TSS the set of tariff classes, tariff structures, charging parameters, a description of how tariffs are set and policies and procedures for assigning/reassigning customers to tariffs[12]
- accompanying the TSS with an indicative five-year price schedule of network prices and update this each subsequent year—this requires forecasting transmission network tariffs[13]
- including in the regulatory proposal overview paper a description of how we engaged with customers and retailers in developing the proposed TSS[14]
- formulating tariffs according to the network pricing objective[15] consistent with pricing principles that include:
  - basing tariffs on the long run marginal cost of serving its different customer groups[16]
  - ensuring only allowed revenue is recovered[17]
  - considering customer impacts in how tariffs are transitioned to give effect to cost-reflective tariff levels[18]
  - ensuring tariff structures are reasonably capable of being understood by customers[19]
  - meeting jurisdictional requirements and regulatory instruments[20]
  - engaging with customers on how we develop the TSS[21] and our tariff structures[22] (including prior to making any changes to the TSS)
  - annual pricing proposals explaining material differences between proposed prices and previous indicative price schedules[23] as well as revising the indicative price schedule every year[24]

[11] NER 6.8.2(c) and 11.76.2

[12] NER 6.18.1A(a)

[13] NER 6.18.1A(e)

[14] NER, 6.18.2(c1a)

[15] NER, 6.18.5(a)

[16] NER, 6.18.5(f)

[17] NER, 6.18.5(g)

[18] NER, 6.18.5(h)

[19] NER, 6.18.5(i)

[20] NER, 6.18.5(j)

[21] NER, 6.18.2(c1a)

[22] NER, 6.18.5(i)

185. This step change relates to forecast opex for the transition to KVA demand charges and the introduction of capacity based prices for Residential and Small Business customers in line with the new network tariff requirements. This includes required changes to billing systems.

14.2 TIMING AND CUSTOMER SUPPORT

186. JEN plans to transition to the kVA based demand changes from 1 January 2017.

187. JEN also plans to publish new tariff structures in line with the TSS requirements on the 1 January 2017. However, JEN won't start billing for the demand of Residential and Small Business customers till 1 January 2018 to allow time for retailers to prepare their systems.

188. The migration process will need to start in June 2016, six months prior to the introduction of new tariff structures, to ensure the transition commencement data is met.

189. Customers have also expressed direct support for this transition path (see our regulatory proposal attachment on our customer, stakeholder and community engagement).

14.3 OPEX STEP CHANGE FORECAST AND SUBSTANTIATION

Table 14–1: New tariffs step change forecast ($2015, $millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Total step change	1.23	0.47	0.25	0.25	0.25	**2.46**

14.3.1 2016 COST FORECAST

190. Approximately 320,000 customers' needs to be progressively transitioned to the new tariff structure. JEN will need to hire a project lead and 2 business analysts to manage and implement this work program.

191. We are expecting a significant increase in call volumes and written enquiries due to the introduction of this material tariff change.

192. We will also need to conduct a mass market mail-out to help ensure our customers are aware of the introduction of the network tariff structure change, including notification that JEN will not start billing for the demand of residential and small business customers till 2018.

[23] NER, 6.18.2(b7A)

[24] NER, 6.18.2(d)

Table 14–2: 2016 cost build-up ($2014, $dollars)

Change	Service	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	17,600	6	120	2.10	$118,800
2	Service desk emails	3,200	6	120	0.63	$36,000
3	Increase in Tariff changes	4,800	6	120	0.95	$54,000
4	Billing emails	3,200	6	120	0.63	$36,000
5	Billing disputes	4,800	6	120	0.76	$43,200
6	Customer relations enquiries	1,600	6	120	0.32	$18,000
7	Retailer communications		1	20	1.00	$9,450
8	Business - UAT		2	40	3.00	$56,700
9	Process changes - Work instructions & Call scripting		2	40	1.00	$18,900
10	Mail out cost	320,000				$320,000
11	Mail out - preparation/content/approvals			20	1.00	$9,450
12	Reporting frame work			10	1.00	$4,725
13	Project lead			140	1.00	$180,000
14	Business analyst			120	2.00	$360,000
	Total					**$1,193,225**

14.3.2 2017 COST FORECAST

193. A second mail-out is prudent to help ensure that the customers are aware that JEN will start billing for the demand of residential and small business customers' from 2018. We are expecting an increase in calls and enquiries relative to CY14 call centre levels. We expect an increase in customer portal enquiries as our customers seek further information on their demand patterns.

Table 14–3: 2017 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	3,000	12	240	0.18	$20,250
2	Service desk emails	1,650	12	240	0.16	$18,563
3	Increase in Tariff changes	1,750	12	240	0.17	$19,688
4	Billing emails	2,400	12	240	0.24	$27,000
5	Billing disputes	4,000	12	240	0.32	$36,000
6	Customer relations enquiries	800	12	240	0.08	$9,000
7	Mail out cost	320,000				$320,000
	Total					**$450,500**

14.3.3 2018-20 COST FORECAST

194. We are expecting an increase in calls and enquiries relative to CY14 levels. Our cost forecasts reflect billing for the demand of residential and small business customers starting 1 January 2018. We expect material increases in billing enquiries and disputes which in turn will have impact on customer relations enquiries.

Table 14–4: 2018-20 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	6000	12	240	0.36	$40,500
2	Service desk emails	3500	12	240	0.35	$39,375
3	Increase in Tariff changes	3500	12	240	0.35	$39,375
4	Billing emails	4800	12	240	0.48	$54,000
5	Billing disputes	6000	12	240	0.48	$54,000
6	Customer relations enquiries	1600	12	240	0.16	$18,000
	Total					**$245,250**