Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 5-3

Application of Incentive Schemes

Public

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GLOSSARY

2008 EBSS	the distribution Efficiency Benefit Sharing Scheme established by the AER in June 2008
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DNSP	Distribution Network Service Provider
DNSPs	Distribution Network Service Providers
DSDBI	Department of State Development, Business and Innovation
EBSS	Efficiency Benefit Sharing Scheme
ESCV	Essential Services Commission of Victoria
F&A	Framework and Approach
f-factor	Fire Factor
GSL	Guaranteed Service Level
JEN	Jemena Electricity Networks (Vic) Ltd
JGN	Jemena Gas Networks (NSW) Ltd
MAIFI	Momentary Average Interruption Frequency Index
MAR	Maximum Annual Revenue
MED	Major Event Days
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NEVA	National Electricity (Victoria) Act 2005
new EBSS	the Efficiency Benefit Sharing Scheme for the 2016 regulatory period
NSP	Network Service Provider
opex	Operating expenditure
RAB	Regulatory Asset Base
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
s-factor	Service Factor
STPIS	Service Target Performance Incentive Scheme

VCR	Value of Customer Reliability
WAPC	Weighted Average Price Cap

OVERVIEW

1. The National Electricity Law (**NEL**) provides for incentive-based regulation[1] that promotes efficient operation of the National Electricity Market. The National Electricity Rules (**NER**) provides a framework to encourage regulated electricity Distribution Network Service Providers (**DNSPs**) to be efficient. In developing incentive schemes, the Australian Energy Regulator (**AER**) is guided by the National Electricity Objective (**NEO**) set out in the NEL which focuses on promoting the long term interests of consumers.

2. This Attachment:

   - Demonstrates the effectiveness of incentive schemes that Jemena Electricity Networks (Vic) Ltd (**JEN**) has responded to historically, which has ultimately delivered significant service and cost efficiency benefits to our customers

   - Sets out JEN positions on incentive schemes that apply in the 2011 regulatory period and that will apply in the 2016 regulatory period, namely::

     - Service Target Performance Incentive Scheme (**STPIS**)

     - Fire factor scheme (**f-factor**)

     - New efficiency benefit sharing scheme (**EBSS**) that applies to operating expenditure (**opex**)

     - Capital Expenditure Sharing Scheme (**CESS**)

     - Demand Management and Embedded Generation Connection Incentive Scheme[2] (**DMEGCIS**) which includes a demand management innovation allowance (**DMIA**)

     - Small-scale incentive scheme.

   - Closure of the retired S-factor scheme that was in operation during the 2006 regulatory period.

3. The purpose of these incentive schemes is to encourage us to outperform regulatory allowances or targets approved by the AER that form part of our revenue requirement over a regulatory control period. The schemes recognise that our customers are better off in the long term if we can continually drive sustainable efficiencies in our business operations.

4. Figure OV–1 outlines the various incentive schemes and the areas that they target to encourage improved outcomes for customers.

5. We do propose a small scale incentive scheme, consistent with the AER's position[3].

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1 NEL, cl. 7A(3)

2 In the 2011 regulatory period this scheme is referred to as the demand management incentive scheme (**DMIS**).

3 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, p. 23

Figure OV–1 - Incentive schemes that apply to DNSPs

1. RESPONDING TO INCENTIVES

6. It is clear that we respond proactively to incentive-based regulation given our lower cost of service and cheaper prices coupled with an outstanding and improving service record (see Attachment 1-2). The financial incentives created by the Essential Services Commission of Victoria (**ESCV**) and now the AER's regulatory framework are aligned with our owners' objectives – to deliver a safe, reliable and affordable service to our customers for the long-term. This is noted by the AER in its response to the Productivity Commission Inquiry into Electricity Network Regulation.[4]

7. Since privatisation of the Victorian electricity sector (back in 1996), we estimate that our response to incentive mechanisms[5] have contributed rewards of approximately $90m ($2015) over the 20-year period—at a 30:70 implied sharing ratio[6]—meaning our customers have enjoyed benefits of around $210m ($2015) over this time.

1.1 OPERATING EXPENDITURE INCENTIVE SCHEMES

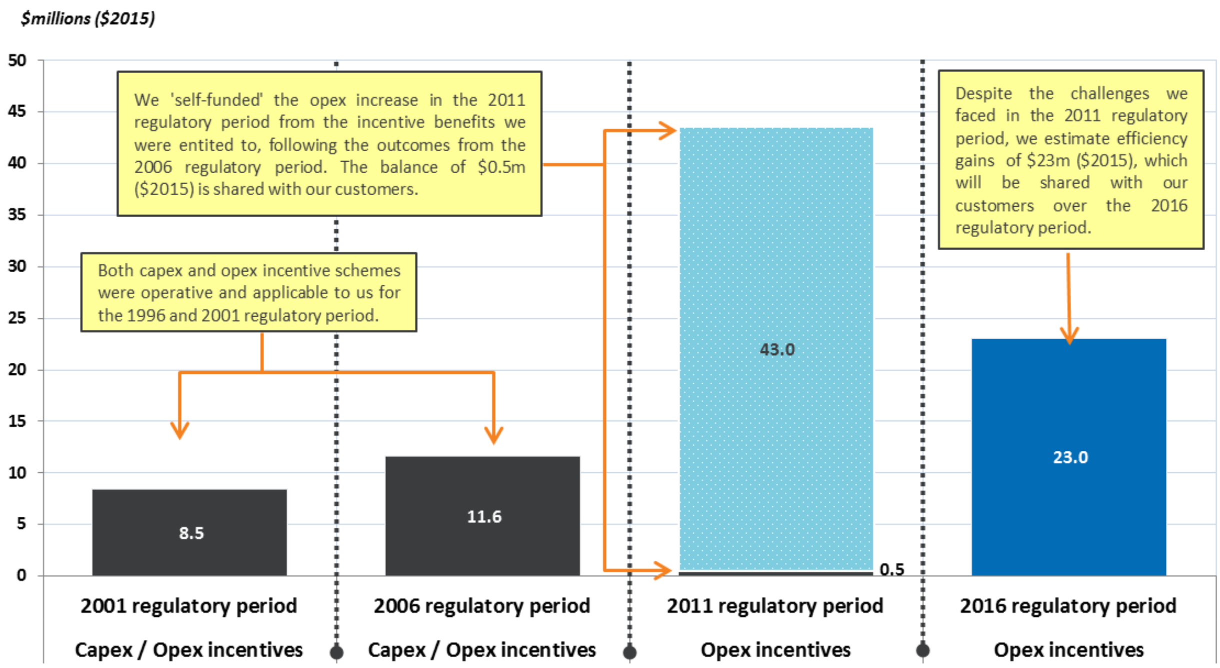
8. The EBSS has been operative since 1995 and we delivered opex efficiencies and corresponding incentive rewards for all four out of four price resets. The EBSS has incentivised behaviours to deliver benefits to shareholders along with savings to our customers (see Figure 1–1).

4 AER, *AER submission to the Productivity Commission Inquiry into Electricity Network Regulation*, April 2012, p. 10

5 Does not include S-factor and STPIS incentive mechanisms as only the EBSS and CESS have sharing ratios.

6 The AER notes on page 7 of its Better Regulation, *Efficiency Benefit Sharing Scheme,* Nov 2013, that under this approach, the benefits of any increase or decrease in opex is shared approximately 30:70 between the NSPs and the customers.

Figure 1–1 Incentive schemes outcomes for each regulatory period since privatisation ($2015, $millions)



Source: Jemena estimates (in conjunction with ESCV and AER past determinations)

(1) The incentive schemes outcome face a lagging factor—for instance, we get rewarded/penalised in the 2001 regulatory period for our performance over the preceding regulatory period (i.e. the 1996 one).

(2) Both capex and opex incentive schemes were operative and applicable to us for the 1996 and 2001 regulatory periods.

1.2 CAPITAL EXPENDITURE INCENTIVE SCHEMES

9. A capital expenditure efficiency carry-over mechanism was operative from 1995 to 2005. Going forward, a new CESS will be re-introduced in the 2016 regulatory period. The CESS is designed to:

- Incentivise capital efficiency by offering rewards for distribution businesses when spending below regulatory allowances, and
- Remove imbalances in the current incentive regime that could potentially result in operating cost efficiencies at the expense of capital expenditure.

2. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

10. This section sets out our proposal in relation to the application of the STPIS, specifically:

- The calculation of actual STPIS outcomes over the 2011 regulatory period, and
- Our proposed way to apply STPIS over the 2016 regulatory period and the resulting target measures.

Box 2-1: Overview of the STPIS

- The STPIS provides an incentive for a DNSP to maintain and improve the reliability of network services. The AER's STPIS[7] comprises the following two mechanisms:
  - *First*, a service factor (**s-factor**) adjustment to annual revenue allowances, rewarding/penalising DNSPs for better/worse performance compared with predetermined (and approved) targets for supply reliability and customer service, and
  - *Second*, a guaranteed service level (**GSL**) component whereby customers are paid if they experience service below a predetermined level.

AER's position for the 2016 regulatory period

- In its final framework and approach (**F&A**) paper[8], the AER proposes to continue to apply its national STPIS to the Victorian DNSPs (noting that in Victoria the GSL component will continue to be excluded given the Victorian based GSL scheme) over the 2016 regulatory period.
- However, the AER proposes to change the calculation of incentive rates to new investments and, if practicable, amend the value of customer reliability (**VCR**) values applicable to future investments consistent with values determined from the most recent Australian Energy Market Operator (**AEMO**) review of VCR values. We note that the AER did not include the Momentary Average Interruption Frequency Index (**MAIFI**) in its final F&A paper.

Our proposal for the 2016 regulatory period

- We *support* the change to the calculation of incentive rates to new investments and amendment of VCR values to AEMO's most recent review of VCR values. *But*, we propose to continue with the MAIFI incentive because:
  - This is aligned with the objectives of STPIS guideline where data is available and consistent with the approach followed in the preceding regulatory period, and
  - Stability in the use of incentive measures allows us to plan targeted reliability investments with a long-term focus, rather than under additional uncertainty—aligned with the long-term interests of customers.
- For the 2016 regulatory period, we also propose:
  - To set the STPIS targets for the 2016 regulatory period based on a consistent method of averaging performance over the past five years (i.e. the average of 2010 to 2014 performance (see section 2.3.2).
  - To continue the existing STPIS on the seven performance measures: urban/short rural Unplanned SAIDI, urban/short rural Unplanned SAIFI, urban/short rural MAIFI, and Telephone Answering, with the exclusion of excluded events as defined in the existing STPIS Clauses 3.3 (a) and major event days (**MED**)[9].

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7. AER, *Electricity distribution network service providers – Service target performance incentive scheme*, November 2009.
8. AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014

11. Table 2–1 sets out our STPIS rewards/penalties of approximately $24m ($2015) and resulting S-factor adjustment[10] that have applied over the 2011 regulatory period.

Table 2–1: S-factor outcomes over 2011 regulatory period ($2015, $million)

	2011	2012	2013	2014	2015
s-factor reward/penalty ($m)			8.8	10.3	4.9
s-factor adjustment (%)			3.91%	0.52%	-2.39%

(1) The S-factor adjustment faces a lagging factor. For instance, our performance in 2011 is reflected in the 2013 prices due to timing.

2.1 REGULATORY REQUIREMENTS

12. Rule 6.3.2(a)(3) of the NER requires that the building block determination must also specify how any applicable STPIS is to apply in the next regulatory control period.

13. Rule 6.4.3(a)(5) of the NER require that the building blocks used to calculate the annual revenue requirements for each year of the regulatory control period must include (among other things) any revenue increments or decrements for the relevant regulatory year arising from any STPIS.

14. Schedule 6.1.3(4) of the NER require that a building block proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any service target performance incentive scheme that has been specified in a framework and approach paper should apply to it.

15. Rule 6.6.2 of the NER requires the AER to develop and publish a STPIS. In general[11] the NER provide that:

16. The framework and approach paper should set out the AER's likely approach as to how the STPIS is likely to be specifically applied in making a determination.

17. A DNSP regulatory proposal must contain at least:

18. As part of the building block proposal, a description, including relevant explanatory material, of how the DNSP proposes the STPIS should apply for the relevant regulatory control period, in accordance with clause S6.1.3(4) of the NER

19. Such information as required under any relevant regulatory information instrument issued by the AER.

20. The Regulatory Information Notice (**RIN**)[12] requires us to provide the detailed methodology for calculating the parameters used in STPIS and justification and details where we propose adjustments to the STPIS targets or in the application of the scheme.

21. The current national distribution STPIS[13] guideline provides a financial incentive to distributors to maintain and improve service performance. It contains an s-factor adjustment and GSL component that operate as part of the building block determination.

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[9] As defined in the existing STPIS Clauses 3.3 (b)

[10] In our annual pricing proposal, we make an S-factor adjustment (see Attachment 5–2) in the pricing formula.

[11] NER, clauses 6.3.2, 6.8.1(b), 6.8.2(c)(2), 6.8.2(d) and 6.12.1.

[12] RIN served 2 February 2015, Schedule 1.7 and s. 23.

[13] AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

22. Under the current STPIS guideline,[14] we can propose to vary the application of the STPIS in its regulatory proposal.

23. In its final F&A paper[15], the AER's proposed approach to applying the STPIS in the next regulatory control period will be to:

24. Set revenue at risk for each distributor within the range nominally, plus or minus 5%

25. Segment the network according to feeder categories (CBD, urban, short rural and long rural as appropriate for each distributor) in the Victorian jurisdictional distribution licence conditions

26. Set applicable reliability of supply (system average interruption duration index or **SAIDI** and system average interruption frequency index or **SAIFI**) and customer service (telephone answering) parameters

27. Set performance targets based on the distributors' average performance over the past five regulatory years

28. Apply the methodology indicated in the STPIS for excluding specific events from the calculation of annual performance targets

29. Apply the methodology and VCR values as indicated in its national STPIS to the calculation of incentive rates to past investments

30. Apply the methodology as indicated in its STPIS to the calculation of incentive rates to new investments and, if practicable, amend the VCR values applicable to future investments consistent with values determined from the most recent AEMO review of VCR values, and

31. The AER will not apply the GSL component.

32. The AER's proposed approach[16] is consistent with its approach for the 2011 regulatory period, other than the change to the calculation of incentive rates to and potential amendment of the VCR values and the removal (by way of not including it in its final F&A paper) of the MAIFI.

2.2 OBJECTIVE OF THE SCHEME

33. The STPIS aims[17] to ensure cost efficiencies (encouraged under the various AER incentive schemes) are not achieved through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the DNSPs' incentives towards aligning its services and prices with the long-term interests of consumers, consistent with the NEO.

2.3 RELIABILITY TARGETS

34. This section sets out our calculation of actual reliability outcomes over the 2011 regulatory period and how we propose to apply reliability STPIS over the 2016 regulatory period, and the resulting proposed STPIS targets.

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[14] ibid, clause 2.2

[15] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.1.1

[16] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.1.1

[17] Ibid, section 3.1.

2.3.1 OUTCOMES OVER 2011 REGULATORY PERIOD

35. Table 2–2 shows our actual reliability STPIS outcomes for the 2010-14 period based on available actual data over the period.

Table 2–2: Our STPIS reliability outcomes over 2010-14

	2010	2011	2012	2013	2014
Unplanned SAIDI	**62.35**	**55.24**	**50.24**	**59.79**	**58.62**
Urban	59.92	52.82	49.75	57.51	57.00
Short rural	100.84	92.78	57.49	114.39	94.27
Unplanned SAIFI	**0.94**	**0.90**	**0.92**	**1.11**	**0.96**
Urban	0.92	0.89	0.93	1.06	0.97
Short rural	1.20	1.04	0.86	2.42	0.67
MAIFI	**0.97**	**0.80**	**0.68**	**0.77**	**0.79**
Urban	0.90	0.73	0.69	0.70	0.76
Short rural	2.00	1.76	0.65	2.39	1.54

(1) The three parameters (highlighted in blue) are calculated as the weighted average of the relevant outcomes for (a) urban and (b) short rural customers[18]. The weights are assigned in accordance with actual customer numbers and taking account of feeder types.

36. The parameters in the above table have been calculated consistently with the AER's final 2011 determination[19] for the 2011 regulatory period where, in determining how the STPIS is to be applied, the AER decided:

37. The three applicable parameters are the (i) unplanned SAIDI, (ii) unplanned SAIFI and (iii) MAIFI reliability of supply parameters, where:

- **Unplanned SAIDI (or how long customers are without power)**—the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).
- **Unplanned SAIFI (or how often customers are without power)**—the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.
- **MAIFI (or how reliable our network is)**—the total number of momentary interruptions divided by the total number of distribution customers.

38. For the reliability of supply parameters our network will be segmented into urban and short rural feeder types and the performance target to apply to each applicable parameter in every regulatory year of the regulatory control period are set out in Table 2–3: STPIS reliability targets over the 2016 regulatory period.

39. In accordance with clause 2.5(a) of the STPIS, the cap on revenue at risk is set at plus or minus 5%. Clause 5.2(b) of the STPIS guideline states that there is a cap on the revenue at risk of plus or minus 0.5% for the telephone answering parameter.

[18] Calculated using same method for 2011-2014 (not the method used in the EDPR 2005-2010)

[19] AER, *Final Jemena Electricity Networks (Victoria) Ltd Distribution determination 2011–2015, October 2010*, section 3.3.3.

40. The incentives rate to apply to each applicable parameter are calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS guideline. The values of customer reliability to be applied in accordance with clause 3.2.2(b) and appendix B of the STPIS.

41. The MED threshold is set to exclude natural events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data. The major event day threshold is to be calculated in accordance with section 3.3 of the STPIS.

42. The 'St' factor derived under the STPIS and applied to the weighted average price control (**WAPC**) formula for 2011 and 2012 will be zero[20].

2.3.2 APPLICATION OVER 2016 REGULATORY PERIOD

43. We agree with the AER's approach set out in its final F&A paper for the 2016 regulatory period in all but one respect—we propose that MAIFI continue to apply under the STPIS (see section 2.3.3).

44. The performance targets to apply during any regulatory control period must be based on average performance over the past five regulatory years.[21] Therefore, based on raw data over the 2010 to 2014 period (being the most recent five years where actual data is available), our proposed STPIS targets over the 2016 regulatory period are as follows shown in Table 2–3.

Table 2–3: STPIS reliability targets over the 2016 regulatory period

	Value
Unplanned SAIDI	
Urban	55.401
Short rural	91.955
Unplanned SAIFI	
Urban	0.954
Short rural	1.238
MAIFI	
Urban	0.756
Short rural	1.654

45. The detailed methodology that we used to calculate the above SAIDI and SAIFI parameters is consistent with the methodology in the AER's current STPIS guideline and the approach in AER's final F&A paper. We also calculated MAIFI consistent with the AER's current STPIS guideline.

2.3.3 REASONS FOR VARYING OR DEPARTING OVER 2016 REGULATORY PERIOD

46. We consider that MAIFI should continue to apply over the 2016 regulatory period as per the AER's current STPIS guideline. We proposes including the MAIFI measure as it is aligned with the objectives of STPIS guideline where data is available[22] and consistent with the approach followed in the preceding (2011) regulatory

[20] AER, *Final decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, section 4.5

[21] STPIS guideline, clause 3.2.1.

[22] Section 3.1(f)

period[23]. Stability in the use of incentive measures allows us to plan targeted reliability investments with a long-term focus, rather than under additional uncertainty. This promotes efficient targeted network investment and is therefore aligned with the long-term interests of customers.

2.4 TELEPHONE ANSWERING TARGETS

47. This section sets out our calculation of our telephone answering performance achieved over the 2011 regulatory period, and our proposed telephone answering targets for the 2016 regulatory period.

2.4.1 OUTCOMES OVER 2011 REGULATORY PERIOD

48. Table 2–4 sets out our telephone answering performance outcomes over 2010 to 2014.

Table 2–4: Customer service outcomes over 2010-14

	2010[24]	2011	2012	2013	2014
Telephone answering	60.34%	60.05%	64.23%	62.95%	73.60%

49. The parameters in the above table have been calculated consistently with the AER's final determination for the 2011 regulatory period whereby in determining how the STPIS is to be applied, the AER decided that[25]:

- The telephone answering customer service parameter is defined as follows:

  Telephone answering: *Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to calls to payment lines and automated interactive services; and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.*

2.4.2 APPLICATION OVER 2016 REGULATORY PERIOD

50. We agree with the AER's approach set out in its final F&A paper for the 2016 regulatory period[26].

51. The current STPIS guideline[27] requires that customer service performance targets must be based on the average actual performance over the past five regulatory years. Therefore, based on raw data over the period 2010 to 2014 (being the latest five year where actual data is available), our proposed customer service target over the 2016 regulatory period is 64.235%.

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23 AER, *Jemena Electricity Networks (Victoria) Ltd Distribution determination 2011–2015*, October 2010, s. 3.3.3

24 Calculated using same method for 2011-2014 (not the method used in the EDPR 2005-2010)

25 AER, *Final decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010

26 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.1

27 ibid, s 5.3.1(a).

52. The detailed methodology that we used to calculate our customer service parameters is consistent with the AER's current STPIS guideline and RIN.

2.5 GURANTEED SERVICE LEVELS

53. As set out above, in its final F&A paper the AER states[28] that it will not apply the GSL component of the STPIS over the 2016 regulatory period given that we (and the other Victorian DNSPs) are subject to a jurisdictional GSL scheme. This position is supported by the Department of State Development, Business and Innovation (Victoria) (**DSDBI**)[29] in its submission to the AER on the replacement F&A.[30]

54. We agree with the AER's proposed approach for the GSL component of the STPIS.

2.6 RECENT AER DECISIONS

55. On 27 November 2014, the AER issued draft decisions on the revenue proposals submitted by ACT and NSW electricity distribution and transmission businesses.

56. The AER's draft decision is to apply its current national STPIS over the next regulatory periods as follows:

- For the NSW electricity distribution businesses, it will apply the s-factor component of its national STPIS to the businesses. The AER will not apply the GSL component given that the existing NSW GSL arrangement will continue to apply over the next regulatory control period. Revenue is capped at plus or minus 2.5% and within this there will be a cap of plus or minus 2.25% for the reliability of supply component and plus or minus 25% for the customer service component
- For Directlink, the AER will apply the service component and the market impact component of version of its national STPIS
- For Transgrid, it will apply all components of its STPIS, and
- For ActewAGL, it will apply the s-factor component of its national STPIS and not apply the GSL component to ActewAGL as the existing ACT GSL arrangement will continue to apply. Revenue at risk for each regulatory year will be capped at plus or minus 5% and within this there will be a cap of plus or minus 0.5% for the customer service component.

57. The AER's proposed approach in its final F&A paper for the Victorian DNSPs is consistent with its draft decisions for the ACT and NSW electricity businesses, other than some variation on the revenue at risk and the exclusion of MAIFI.

28 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.1.1.

29 As of 1 January 2015 the former Department of State Development, Business and Innovation has been incorporated into the new Department of Economic Development, Jobs, Transport and Resources

30 DSDBI, *Submission: Preliminary positions on replacement framework and approach (for consultation)*,July 2014, pp.5-6.

2.7 INTERRELATIONSHIPS WITH OTHER PARTS OF OUR REGULATORY PROPOSAL

58. In its final F&A[31] paper, the AER considered the interaction of STPIS with other incentive schemes. In summary:

- The STPIS counterbalances the incentive to reduce operating costs that the EBSS provides by discouraging cost efficiencies arising through reduced service performance for customers.
- The performance targets will reflect planned reliability improvements and therefore any incentive to reduce capital expenditure (**capex**) under CESS by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

59. The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation. That is, the STPIS provides an incentive to maintain network performance balanced against incentives to defer or avoid network investment.

[31] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, page 102.

3. FIRE FACTOR

60. This section sets out our proposed approach to f-factor scheme over the 2016 regulatory period.

Box 3–1: Overview of the f-factor incentive framework we face

- The scheme is implemented by an Order issued under the National Electricity (Victoria) Act 2005[32]. This Order confers functions and powers on the AER to regulate the f-factor scheme.
- The objective of the f-factor scheme is to provide incentives for Victorian DNSPs to:
  - Reduce the risk of fire starts due to electricity infrastructure, and
  - Reduce the risk of loss or damage caused by fire starts.

AER's position for the 2016 regulatory period

- In its final F&A paper[33], the AER proposes to continue to apply the incentive rates determined in the 2011 regulatory period.
- Give that there is only two years' experience operating the scheme, the AER's position is that it:
  - Would maintain the incentive rate of $25,000 per fire start above or below the predetermined targets for the 2016 regulatory period and continue to monitor the effect of the initial incentive mechanism. DSDBI advised that it will review the scheme in 2015,
  - Will apply the scheme in its amended form, as advised by DSDBI and intends to apply to incentive mechanism in a manner similar to the other incentive schemes, such as the STPIS. Hence, the AER intends to include an adjustment amount for the f-factor in the Maximum Annual Revenue (**MAR**) calculation formula to give effect to the reward or penalty outcomes of actual fire starts above or below predetermined targets under the scheme from the year commencing on 1 January 2016, and
  - Will include in this calculation any amounts that due to lag effect have not been paid or recovered in the 2011 regulatory period. This will remain in place unless changed or discontinued by the Victorian Government, subject to any steps necessary to amend or close out the scheme.

Our proposal for the 2016 regulatory period

- We *agree* with the AER's proposed approach, to be applied over the 2016 regulatory period to apply the incentive rates as determined in the 2011 regulatory period. *But*, we propose amending the targets in line with a rolling moving average over the period of 2012 to 2014, i.e. moving the target up from 56.8 to 72.3. This is because:
  - On our network area, the three years prior to 2012 (i.e. 2009 to 2011), we faced an abnormally high amount of rain, which is reflected in a significantly reduced number of pole top fire starts in the Jemena area and across Victoria. As our pole top fires represent approximately 80% of all fire starts, if a target is derived using abnormal years, this will set an unachievable target for us, and
  - This is supported the analysis undertaken by Energy Safe Victoria (ESV) in which fire starts and rainfall is inversely correlated and resulted in in artificially low targets (p. 66).

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[32] Energy and Resources Legislation Amendment Bill 2010, Explanatory Memorandum, p.10.

[33] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014

3.1 OUTCOMES OVER 2011 REGULATORY PERIOD

61. Table 3–1 sets out our actual f-factor outcomes over 2012 to 2014 based on actual data over the period from when the scheme was introduced.

Table 3–1: Our f-factor outcomes over 2012 to 2014

	2010	2011	2012	2013	2014
f-factor fire starts			**42**	**91**	**84**

4. EFFICIENCY BENEFIT SHARING SCHEME

62. This section sets out our proposal in relation to the application of the EBSS. It deals with:

- The calculation of the EBSS carryover amounts in the 2011 regulatory period, which are included in our proposed annual revenue requirement over the 2016 regulatory period, and
- The way in which we propose to apply the EBSS over the 2016 regulatory period.

Box 4–1: Overview of the EBSS incentive framework we face

- The objective of the EBSS is to provide a continuous incentive for DNSPs to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices[34].
- For the 2011 regulatory period, the AER established a distribution EBSS in June 2008, where it identifies five specific exclusions from the EBSS, namely (i) debt raising costs, (ii) self-insurance costs, (iii) superannuation costs for defined benefits and retirement schemes, (iv) the DMIA and (v) GSL payments.
- The current EBSS also provides for adjustments to forecast opex allowances for the purposes of calculating the carryover amounts, such as (i) changes in capitalisation policy and (ii) growth factor adjustments.
- We achieved efficiency gains of $23m ($2015) over the 2011 regulatory period, which will be shared with our customers over the 2016 regulatory period.

AER's position for the 2016 regulatory period

- For the 2016 regulatory period, the AER developed a new EBSS which is set out in its guideline, AER, Efficiency benefit sharing scheme, November 2013 (new EBSS), which retains the same form as the 2008 EBSS, and merges the distribution and transmission schemes.
- Changes in the new EBSS relate to the AER no longer allowing for specific exclusions (such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth). However, the AER may exclude categories of opex not forecast using a single year revealed cost approach from the EBSS on an ex post basis if doing so better achieves the NER.
- The new EBSS also enables adjustments to the base year opex to remove the impacts of one of the above factors and clarifies how the AER will determine the carryover period.
- In its final F&A, the AER proposes[35] to apply its new EBSS to us for the 2016 regulatory period. The AER states that the determination for JEN will specify how this new EBSS will be applied in the 2016 regulatory period.

Our proposal for the 2016 regulatory period

- We *propose* to adopt the AER's new EBSS, *but* propose the following specific exclusions, for items:
  - Not forecast using a single year revealed cost approach, but rather is a specific forecast cost. Consistent with clause 2.1.1 of the AER's EBSS guideline[36]. The exclusions include (i) debt raising costs, (ii) non-

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34 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.2.

35 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.2.1.

36 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

network alternative costs, self-insurance, DMEGCIS costs, GSL payments, EDPR costs and loss on scrapping of assets, and

  - Costs beyond our reasonable control. The exclusions include (i) the impact of superannuation defined benefit schemes and (ii) the impact of any pass-throughs (see section 4.3).

- We carefully examined the AER's new EBSS and we consider our proposal:
  - Is consistent with the AER's new EBSS, avoiding the risk that the EBSS provides windfall gains or losses
  - Is consistent with fair sharing of rewards/penalties between us and our customers
  - Maintains the integrity of the scheme by ring-fencing capex away from the EBSS
  - Avoids us being rewarded or penalised for changes in assumptions rather than efficiency improvements that we drive, and
  - It avoids us being rewarded or penalised for variances in opex that are outside of our control.
- When the EBSS, CESS and STPIS apply to us, incentives for opex, capex and service are balanced. The schemes provide us with an incentive to pursue efficiency improvements in opex and capex, and to share them with our consumers.

4.1 REGULATORY REQUIREMENTS

63. The relevant regulatory requirements for the EBSS are:

- Rule 6.3.2(a)(3) of the NER require that the building block determination must also specify how any applicable EBSS is to apply in the next regulatory control period.
- Rule 6.4.3(a)(5) of the NER require that the building blocks used to calculate the annual revenue requirements for each year of the regulatory control period must include (among other things) any revenue increments or decrements for the relevant regulatory year arising from any EBSS.
- Schedule 6.1.3(3) of the NER require that a building block proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any EBSS that has been specified in a framework and approach paper should apply to it.

64. The EBSS that applies to us in the 2011 regulatory period is the EBSS specified in the AER's 2011 Determination. The 2011 Determination refers to the EBSS as set out in the AER's F&A for JEN dated 29 May 2009, which in turn refers to the distribution EBSS established by the AER in June 2008 (**2008 EBSS**).[37]

65. The 2011 Determination identifies the following categories of opex which are to be specifically excluded from the EBSS for the 2011 regulatory period:

- Debt raising costs
- Self-insurance costs
- Superannuation costs for defined benefits and retirement schemes

[37] AER, *Electricity distribution network service providers, efficiency benefit sharing scheme*, 26 June 2008.

- The DMIA, and
- GSL payments.

66. The 2008 EBSS also provides for adjustments to forecast opex allowances for the purposes of calculating carry-over amounts, such as for changes in capitalisation policy and growth factor adjustments over the regulatory control period.

67. To calculate the growth factor adjustments (to acknowledge that the actual growth of our network may differ from the original forecasts—set back in 2010), the AER will compare actual values for customer numbers, the number of distribution transformers and zone substation capacity (in MVA) and line length (in kms) for the years 2011 to 2014 and a revised estimate for 2015, with the forecasts of these metrics used in the final decision using the scale escalation method described in appendix J of the AER's 2011 Determination.

68. The EBSS to apply in the 2016 regulatory period must be developed and implemented in accordance with rule 6.5.8 of the NER whereby the AER must have regard to the following matters in developing and implementing an EBSS:

- The need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- The need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure
- The desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- Any incentives that DNSPs may have to capitalise expenditure, and
- The possible effects of the scheme on incentives for the implementation of non-network alternative.

4.1.1 AER'S BETTER REGULATION GUIDELINE ON EBSS

69. The AER developed a new EBSS which is set out in its guideline, AER, *Efficiency benefit sharing scheme*, *November 2013* (**new EBSS**), which retains the same form as the 2008 EBSS, and merges the distribution and transmission schemes.

70. Changes in the new EBSS relate to the AER no longer allowing for specific exclusions (such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth). However, the AER may exclude categories of opex not forecast using a single year revealed cost approach from the EBSS on an ex post basis if doing so better achieves the NER.

71. The new EBSS also enables adjustments to the base year opex to remove the impacts of one of the above factors and clarifies how the AER will determine the carryover period.

72. In its final F&A, the AER proposes[38] to apply its new EBSS to us for the 2016 regulatory period. The AER says that the distribution determination for JEN will specify how this new EBSS will be applied in the 2016 regulatory period.

73. In addition, the RIN[39] requires JEN to:

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[38] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.2.1.

[39] Regulatory Information Notice served 2 February 2015, clause 22.

- Provide forecast and actual opex to calculate the carryover amounts that arise from applying the EBSS during the current regulatory control period
- Identify all changes in JEN's capitalisation policy during the current regulatory control period and provide the impact, reasons, and the effect on forecast and actual opex for each year of the current regulatory control period, and
- Identify all cost categories proposed to be excluded from the EBSS and provide reasons for their exclusion.

74. The RIN[40] also requires JEN to provide justification and details where we propose adjustments to the AER's new EBSS. We propose no adjustments to the AER's new EBSS.

4.2 OUTCOMES OVER 2011 REGULATORY PERIOD

75. This section sets out the calculation of the EBSS carryover amounts in the 2011 regulatory period which included in our proposed annual revenue requirement over the 2016 regulatory period (see Table 4–1)

Table 4–1: Our EBSS outcomes over the 2011 regulatory period ($2015, $millions)

	Actual						Est.	Carryover amount included in annual revenue requirement				
Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Actual / expected	57.85	69.51	69.74	79.00	75.94	74.32	73.19					
Allowed	77.08	78.85	65.15	63.87	64.10	69.72	68.59					
Efficiency amount	**19.23**	**9.34**	**-4.59**	**-15.13**	**-11.84**	**-4.60**	**-4.60**					
Incremental eff.	**X**	**X**	**5.29**	**-10.53**	**3.28**	**7.24**	**0.00**					
2011 Carryover				5.29	5.29	5.29	5.29	5.29				
2012 Carryover					-10.53	-10.53	-10.53	-10.53	-10.53			
2013 Carryover						3.28	3.28	3.28	3.28	3.28		
2014 Carryover							7.24	7.24	7.24	7.24	7.24	
2015 Carryover								0.00	0.00	0.00	0.00	0.00
Total carryover	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**5.29**	**-0.01**	**10.52**	**7.24**	**0.00**

(1) The carryover amount included in our annual revenue requirements over the 2016 regulatory period is based on the relative opex performance over 2009 to 2014. This is consistent with the AER's 2008 EBSS.

76. In calculating the EBSS carryover, we calculated the carryover amount in accordance with the 2008 EBSS. The basis of adjustments made by JEN to determine the AER's allowances and the actual (and expected) opex for EBSS purposes is set out in sections 4.2.1 and 4.2.2 respectively.

4.2.1 DETERMINATION OF AER'S OPEX ALLOWANCES FOR EBSS

77. Table 4–2 sets out the AER's opex allowance for EBSS purposes over the 2011 regulatory period.

40 AER, *Regulatory Information Notice,* dated 2 February 2015, clause 1.7.

Table 4–2: AER's opex allowances for EBSS over 2011 regulatory period ($2015, $millions)

	Actual						Estimate
Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
AER opex allowances	71.38	73.04	66.03	64.79	65.04	70.69	69.59
Adjustments:							
Growth factor adjustment	0.47	0.58	-0.01	-0.01	-0.01	-0.01	-0.01
Capitalisation policy changes	5.23	5.23					
Exclusions:							
Debt raising costs	0.00	0.00	-0.51	-0.54	-0.57	-0.59	-0.61
Self-insurance costs	0.00	0.00	-0.12	-0.12	-0.12	-0.12	-0.12
DMIA	0.00	0.00	-0.23	-0.23	-0.23	-0.23	-0.23
GSL payments	0.00	0.00	-0.02	-0.02	-0.02	-0.02	-0.02
AER opex allowances for EBSS	**77.08**	**78.85**	**65.15**	**63.87**	**64.10**	**69.72**	**68.59**

(1) The opex allowances are sourced from the ESCV's and AER's final determination (post merits review where applicable), and converted from real 2005 and real 2010 dollars to real 2015 dollars, using actual inflation (Sep to Sep quarter).

(2) Consistent with the AER's 2008 EBSS, the incremental gains or losses are calculated using opex data over the period 2009 to 2014.

78. The above adjustments and exclusions reflect the operation of the EBSS for 2011 regulatory period as set out in the AER's 2011 Determination.

79. Importantly, we note that we did not change our capitalisation policy over the 2011 regulatory period, and we made adjustment to the AER's opex allowances in relation to differences in the growth factor. Our calculations are illustrated in Attachment 8–3.

4.2.2 DETERMINATION OF ACTUAL (AND EXPECTED) OPEX FOR EBSS

80. Table 4–3 sets out our actual (and expected) opex for EBSS purposes over the 2011 regulatory period.

Table 4–3: Our actual (and expected) opex for EBSS over 2011 regulatory period ($2015, $millions)

	Actual						
Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Actual (and expected) opex	59.37	69.91	70.07	79.88	76.66	74.85	
Adjustments:							
Growth factor adjustment	0.00	0.00	0.00	0.00	0.00	0.00	
Capitalisation policy changes	0.00	0.00					
Exclusions:							
Debt raising costs	0.00	0.00	0.00	0.00	0.00	0.00	
Self-insurance costs	-1.89	-0.32	-0.29	-0.87	-0.60	-0.39	
DMIA	0.00	0.00	0.00	0.00	-0.05	-0.07	
GSL payments	0.37	-0.08	-0.03	-0.01	-0.07	-0.07	
Actual / expected opex for EBSS	**57.85**	**69.51**	**69.74**	**79.00**	**75.94**	**74.32**	**73.19**

(1) At the time the AER makes its final determination for our EDPR16-20 proposal, the actual opex for 2015 is not readily available. The AER assumes that the incremental opex efficiency for 2015 is zero, and will account for the difference between the actual and opex allowances in the 2021 carryover amount. This is consistent with the AER's 2008 EBSS.

81. The above adjustments and exclusions reflect the operation of the EBSS for 2011 regulatory period as set out in the AER's 2011 Determination.

4.3 APPLICATION OF EBSS OVER 2016 REGULATORY PERIOD

82. We generally support the application of the AER's new EBSS over the 2016 regulatory period. *But*, in applying the AER's new EBSS over the 2016 regulatory period, we propose that a number of cost categories be excluded for:

- Costs that are not forecast using a single year revealed cost approach but rather is a specific forecast cost. Consistent with clause 2.1.1 of the AER's EBSS guideline,[41] such costs are to be excluded from the operation of the EBSS:
  - Debt raising costs
  - Non-network alternative costs—to account for the impact of, for example, demand management alternatives converting forecast capex spend into actual opex spend
  - Self-insurance amounts
  - DMEGCIS costs—in addition, these costs are subject to the AER's DMEGCIS and should not be included in two schemes
  - GSL payments—these are subject to a separate jurisdictional GSL scheme and should not be included in two schemes.
  - EDPR costs—costs incurred for preparing the EDPR proposal. (See Attachment 8-6), and

41 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

- Losses on the scrapping of assets.

- Costs beyond our reasonable control. Examples include:
  - The impact of superannuation defined benefits schemes—these reflect changes in provisions resulting from application of Australian Accounting Standards, and
  - The impact of any pass-throughs.

4.4 REASONS FOR VARYING OR DEPARTING OVER 2016 REGULATORY PERIOD

83. Table 4 summarises the reasons and justification for JEN's proposed departures from the new EBSS.

Table 4: JEN's proposed adjustments to the new EBSS over 2016 regulatory period

Opex item	Reasons for variation	How the variation aligns with the objectives of the EBSS	How the variation impacts the operation of the EBSS
Debt raising	Not forecast using a single year revealed cost approach	Is consistent with the AER's new EBSS and avoids the risk that the EBSS provides windfall gains or losses to JEN	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
Non-network	Not forecast using a single year revealed cost approach	Is consistent with the AER's new EBSS and avoids the risk that the EBSS provides windfall gains or losses to JEN	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
Self-insurance	Not forecast using a single year revealed cost approach	Is consistent with the AER's new EBSS and avoids the risk that the EBSS provides windfall gains or losses to JEN	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
DMEGCIS	Not forecast using a single year revealed cost approach, and subject to DMEGCIS	Is consistent with the AER's new EBSS and avoids the risk that the EBSS provides windfall gains or losses to JEN. Also, creating a double incentive is inconsistent with fair sharing of rewards/penalties between AJEN and its customers	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
GSL	Not forecast using a single year revealed cost approach, and subject to jurisdictional GSL scheme	Is consistent with the AER's new EBSS and avoids the risk that the EBSS provides windfall gains or losses to JEN. Also, creating a double incentive is inconsistent with fair sharing of rewards/penalties between AJEN and its customers	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
Losses on the scrapping of assets	Losses on the scrapping of assets relates to capital items brought to account, their inclusion in the operating expenditure EBSS scheme would distort scheme operation	By ring-fencing capex away from EBSS the integrity of scheme as an opex incentive is maintained	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex

Opex item	Reasons for variation	How the variation aligns with the objectives of the EBSS	How the variation impacts the operation of the EBSS
Defined benefit superannuation provisions	Does not accurately reflect the costs faced by JEN	It avoids JEN being rewarded or penalised for changes in assumptions rather than efficiency improvements driven by JEN	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex
Pass through events	Is a cost that JEN does not control which if included is not consistent with providing a continuous incentive to reduce opex	It will avoid JEN being rewarded or penalised for variances in opex that is outside of its control	Needs to be excluded from the AER's opex allowance subject to the EBSS as does JEN's actual opex

84. In relation to costs beyond our reasonable control, the AER's position in its new EBSS represents a significant shift in the AER's position on exclusion of uncontrollable costs set out in its 2008 EBSS. The AER has previously considered that it was not appropriate for DNSPs to receive benefits or penalties through the EBSS for variances in its opex for cost categories over which they have no control, and has noted that exclusion of these cost categories is therefore consistent with the requirements of the Rules.

85. We believe that the AER's new approach will lead to rewards or penalties through the new EBSS for variances in opex that are outside of our control, and does not provide DNSPs with a continuous incentive to reduce opex, as required by the Rules.[42]

86. Further, in relation to the impact of superannuation defined benefits schemes – in its recent draft decisions[43] for Ausgrid and Endeavour Energy, the AER stated that:

> *"In calculating carryover gains or losses, we must be satisfied that the actual and forecast opex accurately reflects the costs faced by the DNSP in the regulatory control period. For the purpose of calculating carryover gains, we do not consider provisions to accurately reflect those costs so we have adjusted the EBSS carryover amounts accordingly. Provisions are a type of accounting adjustment which reflects revised estimates of future costs a business expects to incur. They are not actual costs. To reward or penalise a service provider for changes in provisions would reward or penalise it for changes in assumptions not efficiency improvements. This would be contrary to the aims of an EBSS under the NER."*

87. We agree with the AER's logic in this regard and propose that such costs be excluded from the operation of the EBSS.

4.5 RECENT AER DECISIONS

88. On 27 November 2014 the AER issued draft decisions on the revenue proposals submitted by ACT and NSW distribution and transmission businesses.

89. The AER's draft decision on application of its national new EBSS over the next regulatory periods is as follows:

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42 NER, Cl. Rule 6.5.8(c)(2)

43 AER, *Draft decision Ausgrid distribution determination 2015-16 to 2018-19 Overview* November 2014, section 9.1.1, and AER, *Draft decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview*, November 2014, section 9.1.1.

- For the NSW electricity distribution businesses and ActewAGL, the new EBSS will not apply given AER is concerned whether their opex is efficient and therefore the AER is unlikely to use its preferred revealed cost approach at the next reviews, and
- For Transgrid and Directlink the AER will apply its new EBSS.

90. For Jemena Gas Networks (NSW) Ltd (**JGN**), the AER will apply an EBSS (this will be the first time an EBSS has applied to JGN) similar to its new EBSS for electricity networks but with exclusions for unaccounted for gas, license fee costs, carbon costs, any relevant tax change (given these are subject to true-ups through the tariff variation mechanism) and debt raising costs (given such costs are not determined through a revealed cost approach).

91. Further, the AER will make adjustments for any changes in its capitalisation policy and may adjust target opex to add or subtract determined pass through amounts. It is the AER's preference to add (or subtract) these pass through amounts to forecast opex rather than adjust actual opex to remove the passed through amount.

4.6 INTERRELATIONSHIPS WITH OTHER PARTS OF OUR REGULATORY PROPOSAL

92. When the EBSS, CESS and STPIS apply to us, incentives for opex, capex and service are balanced. The schemes provide us with an incentive to pursue efficiency improvements in opex and capex, and to share them with our consumers.

93. Incentives for opex and capex are balanced (at approximately 30 per cent) under the implied fair sharing ratio. The incentives are also balanced in that the STPIS encourages us to make targeted efficient decisions on when and what type of expenditure to incur, in order to meet our service reliability targets.

94. The AER's current EBSS is based on the premise that the AER adopts a revealed cost approach to setting the efficient base year opex. Attachment 8-2 sets out our opex forecasts based on the AER's 'base, step and trend' approach using revealed costs.

5. CAPITAL EXPENDITURE SHARING SCHEME

95. This section sets out our proposal in relation to the application of the AER's CESS over the 2016 regulatory period.

Box 5–1: Overview of the CESS

- The CESS provides financial rewards for JEN if our capex becomes more efficient and imposes financial penalties if we become less efficient. Consumers benefit from improved efficiency through lower regulated prices.[44].
- The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between JEN and network users.
- Under the CESS JEN retains 30% of an under or under spend relative to regulatory allowances, while consumers retain the residual 70%.

AER's position for the 2016 regulatory period

- The AER proposes to apply the CESS, as set out in the capex incentives guideline[45].

Our proposal for the 2016 regulatory period

- We proposes to *largely adopt* the AER's CESS over the 2016 regulatory period *but* propose that:
  - Reliability improvement capex and any capex related to pass-throughs be excluded from the scheme, and
  - CESS outcomes over the 2016 regulatory period be amortised over the 2021 regulatory period.
- We consider this approach to be reasonable because otherwise:
  - The STPIS incentives to improve network reliability (through increase in capex) are flawed, and
  - This would create asymmetry in the time horizon of benefits and penalties between the EBSS and the CESS.
- We note that it is not clear how the AER will adjust our revenue requirements in the 2021 regulatory period to reflect the CESS outcomes over the 2016 regulatory period and for the true-up of 2020 actual outcomes in the 2026 regulatory period. We encourage the AER to consult broadly with the industry on how it proposes to adjust revenues for CESS outcomes.
- Further, if the AER is required to complete an ex-post review of capex, it will require significant interaction with us. Therefore, we advocate that the AER conducts a full and transparent consultation with it at all stages of any ex-post review.

5.1 REGULATORY REQUIREMENTS

96. Rule 6.3.2(a)(3) of the NER require that the building block determination must also specify how any applicable CESS is to apply in the next regulatory control period.

[44] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.4.3

[45] AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9

97. Rule 6.4.3(a)(5) of the NER require that the building blocks used to calculate the annual revenue requirements for each year of the regulatory control period must include (among other things) any revenue increments or decrements for the relevant regulatory year arising from any CESS.

98. Schedule 6.1.3(3A) of the NER require that a building block proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any CESS that has been specified in a framework and approach paper should apply to it.

99. Rule 6.5.8A of the NER sets out the factors that the AER is required to take into account in developing a CESS. In deciding the nature and details of any CESS to apply, the AER must:

- Make that decision in a manner that contributes to the capex incentive objective;[46] and
- Consider the CESS principles,[47] interaction of the CESS with incentive schemes, capex objectives, and where relevant the opex objectives,[48] as they apply to the particular DNSP, and the circumstances of the DNSP.[49]

100. The AER will also introduce ex-post measures to ensure that only efficient capex rolls into the regulatory asset base (**RAB**). These ex-post measures are derived from Schedule 6.2.2A of the NER which outlines the circumstances in which the AER may reduce the amount by which a DNSP's RAB is to be increased as part of the RAB roll forward.

101. In its final F&A paper, the AER stated that it will apply the CESS, as set out in its capital expenditure incentive guideline in the 2016 regulatory period.[50]

102. The CESS will work as follows[51] at the end of the 2016 regulatory period:

- The cumulative underspend or overspend for the 2016 regulatory period will be calculated in net present value terms
- A sharing ratio of 30% will be applied to the cumulative underspend or overspend to work out what our share of the under or over spend should be
- The CESS payments will be calculated taking into account the financing benefit or cost to us relating to the over or under spends. The AER may adjust to account for deferral of capex and ex post exclusions of capex from the RAB
- The CESS payments will be added or subtracted to our regulated revenue requirements as a separate building block in the 2021 regulatory period
- The CESS provides for a final year (2020) true-up in the subsequent regulatory period (2021 regulatory period). It is not clear how the AER will adjust our regulated revenue requirements for CESS payments, and
- The RIN[52] requires us to provide justification and details where we propose adjustments to the AER's CESS.

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46 NER, Cl 6.5.8A(e).

47 NER, Cl 6.5.8A(c).

48 NER, Cl 6.5.8A(d).

49 NER, Cl 6.5.8A(e).

50 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.3.1

51 AER, *Capital expenditure incentive guideline*, November 2013, s2.3.

5.2 OBJECTIVE OF THE SCHEME

103. The overarching objective[53] of the CESS is to provide DNSPs with an incentive to undertake efficient capex during a regulatory control period. It achieves this by rewarding DNSPs that outperform their capex allowance and penalising DNSPs that spend more than their capex allowances. The CESS also provides a mechanism to share efficiency gains and losses between DNSPs and network users (or their customers).

5.3 APPLICATION OF THE CESS OVER 2016 REGULATORY PERIOD

104. We propose to apply the AER's CESS over the 2016 regulatory period to its gross capex (consistent with the AER's preferred approach[54]). However, we also propose to exclude reliability improvement capex and capex approved as a part of a pass-through application.[55]

105. We note that the AER opposed to exclude reliability improvement capex in its CESS on the basis that such expenditure is funded by the STPIS and for which, typically, no allowance is requested or approved. The AER considered that it was better to deal with the interaction between the CESS, EBSS and STPIS through its intended review of the STPIS. However, the AER's intended review of its STPIS has not been completed.

106. Therefore, we believe that it is appropriate that reliability improvement capex be excluded from the CESS over the 2016 regulatory period.

107. We also propose CESS amounts to be included in our regulated revenue requirements and amortised over the 2021 regulatory period, to avoid asymmetry in time horizon of benefits and penalties between the EBSS and the CESS (i.e. over a five year period), noting that the AER's post-tax revenue model gives effect to the CESS as a revenue adjustment.

5.4 EX-POST MEASURES OF EFFICIENT CAPEX

108. The AER may exclude capex from the RAB under an ex-post review:

- When we spend an amount of capex above our regulatory allowances that does not reasonably reflect the capex criteria can be excluded from the RAB
- Where there is excessive related party margin, the excessive portion of the margin can be excluded from the RAB, and
- Where a change to our capitalisation policy has led to opex being capitalised, the capitalised opex can be excluded from the RAB.

109. The ex-post review will be undertaken by the AER for the first time as part of the distribution determination process for the 2021 regulatory period. The relevant period over which the assessment is to occur (i.e. the review period) is the first three years of the regulatory control period just ending (i.e. 2016, 2017 and 2018) and the last two years (i.e. 2014 and 2015) of the preceding regulatory control period. This differs from the period for the CESS.

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52 RIN served 2 February 2015, clause 1.7.

53 AER, *Capital expenditure incentive guideline*, November 2013, s2.1.

54 Paul Dunn, *Email to Eli Grace-Webb, RE: IMPORTANT INFORMATION : Indicative positions in the Vic F&A [SEC=UNCLASSIFIED]*, 5 November 2014.

55 NER cl. 6.6.1

110. We advocate that full and transparent consultation be undertaken at all stages of any ex-post review.

5.5 RECENT AER DECISIONS

111. On 27 November 2014 the AER issued draft decisions on the revenue proposals submitted by ACT and NSW electricity distribution and transmission businesses. In its draft decisions the AER stated that it will apply its national CESS to all businesses over the next regulatory periods.

5.6 INTERRELATIONSHIPS WITH OTHER PARTS OF JEN'S REGULATORY PROPOSAL

112. When the CESS, EBSS and STPIS apply to us, incentives for opex, capex and service are balanced. The schemes give us an incentive to pursue efficiency improvements in opex and capex, and to share them with its consumers. Incentives for opex and capex are balanced (30 per cent) and constant. The incentives are also balanced with the incentives under the STPIS which encourages JEN to make efficient decisions on when and what type of expenditure to incur, in order to meet its service reliability targets.

6. DEMAND MANAGEMENT AND EMBEDDED GENERATION CONNECTION INCENTIVE SCHEME

113. This section sets out our proposal in relation to the application of the DMEGCIS.

114. We have been very active developing innovative non-network solutions—ranking first amongst its peers[56]—and expects to spend its full allowance by the end of the 2011 regulatory period. In fact our commitment to further develop non-network solutions has been constrained by unnecessarily low restriction on the DMIA allowances set by the AER.

Box 6–1: Overview of the DMEGCIS

- The objective of the DMEGCIS is to provide an incentive for us to pursue non-network solutions to the providing standard control services. Consumers benefit in the longer term efficiency gains when the program developed under the scheme are deployed more broadly[57].
- For the 2011 regulatory period, the AER established a DMIS[58] to, where it identifies two streams of allowance, (i) a demand management innovation allowance and (ii) compensation for foregone revenue; part two of this scheme will not apply to JEN given it is morning to a revenue cap form of price control.
- We classify demand management solutions as non-network solutions that do not involve building of traditional network assets (poles and wires). These include, but are not limited to tariff offerings, demand response, embedded generation, energy storage solutions and energy efficiency incentive programs.

AER's position for the 2016 regulatory period

- For the 2016 regulatory period, the AER developed a new DMEGCIS which is largely the same as the scheme used in the 2011 regulatory period with only editorial changes.

Our proposal for the 2016 regulatory period

- We propose to adopt the AER's new DMEGCIS, and propose to lift the allowance from $1m in the 2011 regulatory period to $5.5m in the 2016 regulatory period given:
  - Our credibility in spending to the allowance
  - A strong case of identified projects targeted for DMEGCIS funding (See attachment 5-5).
- Our objectives over the 2016 regulatory period for demand management are to:
  - Develop options and flexibility for both our network and customers through the application of demand management solutions.
  - Establish policy, systems and processes that support demand management
  - Where economical, resolve network supply quality and capacity constraints using demand management

56 AER, *Decision, Applications by DNSPs for Demand Management Innovation Allowance for: -2013 calendar year (Victorian DNSPs); and - 2012–13 financial year (all other DNSPs)*, April 2015, Pg. 4

57 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.4.3

58 AER, *DMIS, CitiPower, Powercor, Jemena, SP AusNet and United Energy*, April 2009.

6.1 REGULATORY REQUIREMENTS

115. The NER require the AER to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.

116. Rule 6.6.3 of the NER sets out the factors that the AER must have regard to in implementing a DMIS.

117. Schedule 6.1.3(5) of the NER require that a building block proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any DMEGCIS that has been specified in a framework and approach paper should apply to it.

118. In its 2011 Determination,[59] the AER decided to apply the Victorian DNSP DMIS[60] to JEN for the 2011 regulatory period. In determining how the DMIS is to be applied, the AER decided that:

119. Part A of the DMIS (that is, the DMIA) will apply to JEN and part B (the forgone revenue component) will also apply to JEN.

120. The DMIA is capped at $1m and allocated to JEN over the 2011 regulatory period.

121. Approval of DMIA amounts by the AER will be subject to satisfaction of the DMIA criteria in the DMIS.

122. In its final framework and approach paper, the AER has stated that it will apply the DMEGCIS as follows:[61]

123. Part A of the DMEGCIS (that is, the DMIA) will apply to JEN

124. Part B of the DMEGCIS (the forgone revenue component) will not apply to JEN given the move to a revenue cap.

125. For the 2016 regulatory period, the DMIA allowance will be determined as part of the AER's revenue determination.

126. In its final framework and approach paper[62], the AER acknowledges the need to reform the existing Victorian demand management incentive arrangements pending the rule changes that results from the COAG Energy Council's (formerly SCER) Power of Choice (particularly those parts examining distributor incentives to pursue efficient alternatives to network augmentation). The Power of Choice review is expected to include new rules and principles guiding the design of a new DMEGCIS. Consequently, the AER may develop and implement a new DMEGCIS during the 2016 regulatory period. The AER expects to apply the new scheme or some variations within the 2016 regulatory period.

6.2 OBJECTIVE OF THE SCHEME

127. Demand management refers to any effort by a distributor to lower or shift the demand for Standard Control Services. Demand management that effectively alleviates network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

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59 AER, *Victorian distribution determination final decision 2011–2015*, 29 October 2010, s 3.3.2.

60 AER, *DMIS, CitiPower, Powercor, Jemena, SP AusNet and United Energy*, April 2009.

61 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.3.1.

62 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, s 3.4.1

128. The AER's DMEGCIS incentivises DNSPs to consider economically efficient alternative to building more network.[63]

6.3 DMIS OUTCOMES OVER 2011 REGULATORY PERIOD

129. In the 2011 Determination the AER capped the DMIA at $1m over the 2011 regulatory period[64].

130. Table 5 outlines the projects that we have implemented over the 2011 regulatory period and the amount we spent or expect to spend on them.

Table 5: Actual/estimated DMIA over the 2011 regulatory period ($2015, $Thousands)

	2011	2012	2013	2014	2015
JEN Energy Portal - Stage 1	523.0	-	-	-	-
JEN Energy Portal - Stage 2	-	242.9	-	-	-
Impact of the Energy Portal on Customers' Consumption Habits	-	-	51.0	38.8	-
Demand Response Field Trial - Phase 1	-	-	-	27.2	26.3
Demand Management - Constraint Assessment Tool	-	-	-	-	49.2
Grid Energy Storage Desktop Study (2)	-	-	-	-	60.0
Technical and economic assessment of Residential Energy Storage (2)	-	-	-	-	60.0
Total DMIA	**523.0**	**242.9**	**51.0**	**66.0**	**195.5**

(1) Source: JEN Analysis

(2) Project not yet committed

131. We will true-up the DMIA balance in the 2017 year being the first time revenues can be adjusted to account for known performance form the 2015 year. The mechanism to effect the adjustment is proposed in Box A5-2 of Attachment 5-2: Price control mechanisms.

6.4 APPLICATION OF DMEGCIS OVER 2016 REGULATORY PERIOD

132. We note that it has demonstrated a willingness to actively participate in the demand management activities which ultimate serve a customers' long term interests, however it has been limited in its activities due to the threshold limits imposed during the 2011 regulatory period.

133. We have a strong desire to be even more proactive exploring initiatives that fall under the DMEGCIS umbrella however has been constrained by the cap on the allowance. Therefore, we propose that the allowance be lifted from $1m during the 2011 regulatory period to $5.5 million dollars during the 2016 regulatory period highlighting a series of programs to target DMEGIS expenditure during the period (see Attachment 5-5).

63 Ibid, s 3.4.

64 AER, *Final decision, Victorian electricity distribution network, service providers, Distribution determination 2011–2015*, October 2010, section 15.6.14.3

6.5 RECENT AER DECISIONS

134. On 27 November 2014 the AER issued draft decisions on the revenue proposals submitted by ACT and NSW electricity distribution businesses. In its draft decisions the AER stated that it will apply the DMIA and allow $1M pa for Ausgrid, $0.6M pa for Essential Energy and Endeavour Energy, and $0.1M pa for ActewAGL.

6.6 INTERRELATIONSHIPS WITH OTHER PARTS OF JEN'S REGULATORY PROPOSAL

135. The scheme will interact with the true-up mechanism in the second regulatory year of the regulatory control period as outlined in Attachment 5–2 of this regulatory proposal.

136. Consistent with the AER's views[65], the proposed DMEGCIS does not distort the operation of the other proposed incentive schemes outlined in this Attachment.

[65] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, section 3.4.3

7. S-FACTOR SCHEME CLOSE OUT

137. This section sets out our proposal in relation to closing out the s-factor[66] scheme that was in place during the 2006 regulatory period but closed out as a part of the transition to the STPIS during the 2011 regulatory period. Closing out of the scheme is necessary during the 2016 regulatory period as actual data for 2010 – required as a part of the calculation – was not available at the time of making the 2011 regulation determination.

7.1 SUMMARY

138. In the AER's final decision on the 2011 distribution determinations for the Victorian electricity DNSPs, the AER decided to close out the ESCV's s-factor scheme and include the financial benefits and penalties accrued in the 2006 regulatory period under the scheme as a building block element in the calculation of allowed revenue for the 2011 regulatory period.

139. The AER also decided that to accurately close out the ESCV s-factor scheme, actual performance for 2010 is required and, as this information would only be available in the first quarter of 2011, it would perform a final reconciliation to account for actual 2010 performance in the 2016-20 determination.

140. While the AER's decision was subject to merits review in *United Energy Distribution Pty Limited* [2012] ACompT 1, amendments were made to the *National Electricity (Victoria) Act 2005* (**NEVA**) in 2012, subsequent to the Australian Competition Tribunal's decision, to enable the application of the AER's decision to the Victorian DNSPs.

141. Therefore, consistent with the AER's decision on the 2011-2015 distribution determination, we have undertaken a final reconciliation to account for actual 2010 performance and propose to include $3.81m ($2015) as a building block item.

Table 6: S-Factor close out summary ($million)

Description	2011	2012	2013	2014	2015	2016
Building Blocks for the S-factor true up ($2010) – estimated	5.46	0.92	-0.20	-0.19	-9.63	
Building Blocks for the S-factor true up ($2010) – actual	5.46	4.27	0.07	0.07	-11.19	
Change in true up ($2010)	-	3.35	0.27	0.27	-1.55	
S-factor true up correction in Building Blocks ($2010)	-	4.68	0.35	0.32	-1.69	3.36
S-factor true up correction in Building Blocks ($2015)						**3.81**

Source: Attachment 6-5

[66] The s-factor scheme is distinct from the STPIS in that the s-factor scheme was in place up until the end of 2010 whilst the STPIS was in effect from the beginning of 2011 onwards

7.2 REGULATORY REQUIREMENTS

We consider that this approach is consistent with rule 6.4.3(a)(5) and (b)(5) of the NER. In particular, subparagraph (a)(5) allows JEN to include as a building block

> "the revenue increments or decrements (if any) for that year arising from the application of any *efficiency benefit sharing scheme*, *capital expenditure sharing scheme*, *service target performance incentive scheme*, *demand management and embedded generation connection incentive scheme* or *small-scale incentive scheme*".

142. Section 16L of the NEVA then modifies the definition of "*service target performance incentive scheme"* to include the s-factor adjustments that applied to the Victorian DNSP under the 2006-10 distribution determination made by the ESCV.

7.3 OUTCOMES OVER 2011 REGULATORY PERIOD

143. In the AER's final decision back in 2010 the AER concluded that the financial benefits and penalties accrued in the 2006-10 regulatory period from the S-Factor Scheme would be included as a building block element in the calculation of the allowed revenue for the 2011 regulatory period. It could not at that time include the results from JEN's actual performance in 2010 and undertook to do so in its 2016-20 distribution determination[67].

7.4 APPLICATION OF THE CLOSE OUT OVER 2016 REGULATORY PERIOD

144. We propose that the amount calculated form a building block adjustment in the first year of the 2016 regulatory period (see Attachment 6-1).

7.5 INTERRELATIONSHIPS WITH OTHER PARTS OF OUR REGULATORY PROPOSAL

145. The $3.81m ($2015) calculated as a part of the s-factor close out:

- Will be included as a building block item as a one off adjustment
- Whilst the s-factor scheme is an incentive mechanism the inclusion of this component only serves to close out a historical activity and bares no correlation to other incentive schemes, and
- This scheme does not overlap with any other incentive scheme in the 2011 or 2016 regulatory periods, in particular the STPIS, and therefore did not distort the rewards or penalties attributed to over or under incentivising.

[67] AER, *Final decision, Victorian electricity distribution network, service providers, Distribution determination 2011–2015*, October 2010, s. 15.6.7.5