Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review
Regulatory Proposal

Attachment 8-1

Historical operating expenditure report for 2011 regulatory period

Public

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ABBREVIATIONS

AER	Australian Energy Regulator
BPSTF	Bushfire Powerline Safety Task Force
DS	Distribution Services
EBS	Enterprise Business Services
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
ELCR	Electric Line Clearance Regulations
EMS	Emergency Management System
ERP	Enterprise Resource Planning
ESV	Energy Safe Victoria
F-factor	Factor
GSL	Guaranteed Service Level
JAM	Jemena Asset Management
JEN	Jemena Electricity Networks (Vic) Ltd
opex	Operating expenditure
PAS 55	Publicly Available Standard 55
regulatory allowances	the AER's 2011–2015 Distribution Determination
RINs	Regulatory Information Notices
SCADA	Supervisory Control and Data Acquisition
SP	Singapore Power
UE	United Energy
VBRC	Victorian Bushfire Royal Commission

1. OVERVIEW

1. The purpose of this document is to explain Jemena Electricity Networks' (Vic) Ltd (**JEN**) distribution services operating expenditure (**opex**) performance over the 2011 regulatory period.

2. This includes identifying circumstances specific to JEN, and comparing our actual (and expected) opex for the 2011 regulatory period to that proposed in our revised 2011-15 Electricity Distribution Price Review (**EDPR**) proposal, and to the regulatory allowance, explaining key differences between them.

Key messages

- Our actual (expected) opex for distribution services for the 2011 regulatory period is $379m ($2015), which is $43m ($2015) or 12.8% higher than the AER's regulatory allowances (see Table 2–1)
- The Australian Energy Regulator (**AER**) set our opex allowances in 2010. Since then, the energy market has significantly evolved, reflected by unforeseen (and mostly uncontrollable) increase in costs, which are primarily due to:
  - Additional regulatory, safety and compliance obligations, which were mandated by Energy Safe Victoria (**ESV**) or the Victorian Bushfire Royal Commission (**VBRC**) including the Bushfire Powerline Safety Task Force (see Table 2–2), and
  - The handing back of some back office functions (which we shared with United Energy (**UE**) via Jemena Asset Management (**JAM**)) resulted in lost cost saving previously realised through synergies. Due to changes in the regulatory treatment of related party margins meant that arrangements with UE no longer produced benefits—for either JEN or UE—resulting in the cessation of the agreement.
- Despite these challenges and our stakeholders' pressures (private shareholders, customers and the regulatory framework), we ensured our costs—incurred to meet these additional obligations and transitionary arrangement following the hand back of shared functions—reflect a prudent service provider acting efficiently
- The AER's efficiency benefit sharing scheme (**EBSS**) is designed to incentivise network service providers to reduce opex over time to outperform regulatory allowances, and also remove any incentive to lower costs in the base year. We have been responding positively to the EBSS for the past twenty years following privatisation
- Importantly, we 'self-funded' this opex increase in the 2011 regulatory period from the EBSS benefits that we are entitled to, following our response to the scheme in the 2006 regulatory period. This means our customers did not pay for these additional costs
- In preparing our opex forecasts for the 2016 regulatory period,[1] we propose 2014 as the base year because this is the latest available information at the time of preparing this regulatory proposal and our expert consultant (Huegin)'s analysis states that there is sufficient evidence to suggest our revealed base year is materially efficient (see Attachment 8–5)
- We also achieved estimated efficiency gains of $23m ($2015), which will be shared with our customers over the 2016 regulatory period.

[1] These forecasts meet the opex criteria (under NER 6.5.6(c) (1) and (2)), and reasonably reflect the (a) efficient costs of achieving the *opex objectives* (under NER 6.5.6(a)) and (b) the costs that a prudent operator would require to achieve the *opex objectives*.

2. OUR PERFORMANCE

3. This section of the report explains:

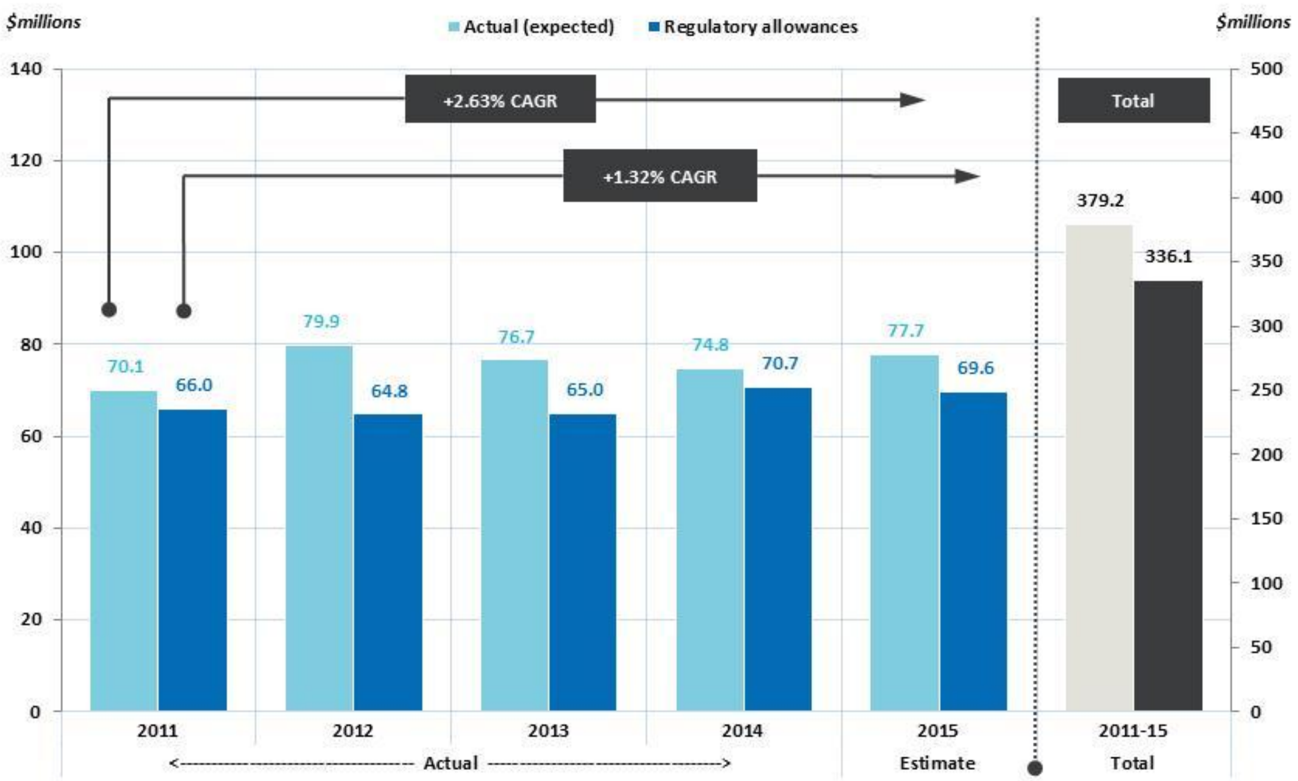
- Our current period distribution services (**DS**) opex, and compares it to the AER's 2011–2015 distribution determination (**regulatory allowances**)
- The key differences between our actual (expected) and regulatory allowances, and
- How we responded to incentives (from our private shareholders, our customers and the regulatory framework) to manage our costs in a way a prudent service network provider acting efficiently would.

2.1 CURRENT PERIOD PERFORMANCE

2.1.1 OUR PERFORMANCE

4. Figure 2–1 summarises JEN's DS opex performance for the 2011 regulatory period against the regulatory allowances. At a total level, JEN expects to incur $379.2m ($2015) of opex over 2011–15, which is $43.0m (or 13%) above the regulatory allowances of $336.1m ($2015).

Figure 2–1: Our DS opex current performance against regulatory allowances ($2015, $millions)



(1) 'Actuals cover the period up to 31 December 2014, with 2015 as an estimate (using base, step and trend approach).

5. Over the period, we faced challenges—an unforseen increase in opex due to additional regulatory, safety and compliance obligations (see Table 2–2)—as well as lost synergies that we had previously benefited from by sharing back office functions with United Energy (**UE**) (who opted to insource these functions from 1 July 2011).

6. Since then, we have reduced the gap between actual and allowed opex over 2012 to 2014, responding to the incentives we face, including those created by the EBSS or other stakeholder pressures from our private shareholders or our customers.

7. The AER assessed our opex under two broad categories, namely 'maintenance' and 'operating' expenditure. JEN presents its current period opex performance in this manner—set out in Table 2–1—with a comparison against the regulatory allowances.

Table 2–1: Actual (and expected) DS opex performance against regulatory allowances ($2015, $millions)

Distribution services opex	Actual				Estimate	Total
	2011	2012	2013	2014	2015	2011-15
Actual (expected)						
Operating	50.17	59.38	49.84	46.84	48.35	254.58
Maintenance	19.90	20.50	26.82	28.01	29.38	124.60
Total opex	**70.07**	**79.88**	**76.66**	**74.85**	**77.72**	**379.18**
Regulatory allowances						
Operating	49.40	47.99	48.71	53.93	52.49	252.51
Maintenance	16.64	16.80	16.34	16.76	17.10	83.63
Total opex	**66.03**	**64.79**	**65.04**	**70.69**	**69.59**	**336.14**
Difference						
Operating	0.77	11.39	1.13	-7.09	-4.14	2.07
Maintenance	3.26	3.70	10.48	11.25	12.28	40.97
Total opex	**4.03**	**15.09**	**11.62**	**4.16**	**8.14**	**43.04**
Difference	***6.1%***	***23.3%***	***17.9%***	***5.9%***	***11.7%***	***12.8%***

Source: AER final determination (post-merits review), JEN's annual regulatory information notices (**RINs**), JEN estimates (for 2015).

(1) Amounts incurred include debt raising costs and are JEN's actuals to 2014 and estimate for 2015.
The allowances were set in 2010 dollars, which are converted to 2015 dollars using actual inflation data (Sep to Sep quarter)[2].

2.1.2 EXPLANATION FOR VARIANCE TO OUR ALLOWANCES

8. Our regulatory allowances were determined in 2010. Since then, the energy market has significantly evolved, reflected by unforeseen (and mostly uncontrollable) increase in costs, primarily due to:

- Additional regulatory, safety and compliance obligations, which were mandated by ESV or the VBRC including the Bushfire Powerline Safety Task Force (see Table 2–2), and
- The handing back of some back office functions (which we shared with UE) resulted in lost cost saving previously realised through synergies.

9. During the 2006 regulatory period, JEN benefited from synergies achieved from amalgamating JEN's former asset manager (**Agility**) with Alinta Asset Management[3], which became Jemena Asset Management (**JAM**).

[2] From the Australian Bureau of Statistics, consumer price index, weighted average of eight capital cities, series ID A2325846C.

[3] JEN, *Regulatory Proposal 2011-15*, 30 November 2009, p.57

This led to group synergy benefits from a large range of services being shared across UE, JEN and other clients.

10. In the 2011 regulatory period, the AER approved allowances that included synergies from sharing functions with UE (via JAM) and assumed these would be ongoing. However, the AER disallowed profit margins that were needed to make the arrangement sustainable. As a result, the cost sharing arrangements were discontinued—resulting in lost cost savings previously achieved.

11. Despite these challengers and our stakeholders' pressures (private shareholders, customers and the regulatory framework), we have ensured that our costs—incurred to meet these additional obligations and transitionary arrangement following the hand back of shared functions—are reflective of a prudent service provider acting efficiently.

12. Our strong governance framework and internal policies ensure that we incur opex only when it is necessary. Examples include:

- Obtaining accreditation to Publicly Available Standard (**PAS) 55**—a world-class standard—that indicates we have sound processes in place to facilitate compliance with relevant governance frameworks (see chapter 7 and Attachment 7–2 of our regulatory proposal)
- Sound budgeting processes
- Adequate delegation of financial authority, and
- Efficient procurement, recruitment and remuneration policies.

13. Our analysis—supported by expert advice from Huegin—indicates that despite the challenges we faced in terms of unforeseen increases in costs, and from being the smallest distribution network service provider in Victoria, our efficiency (productive, allocative or dynamic[4]) is comparable to that of our network peers (see Attachment 8–5).

14. We are committed to ensuring the safety and reliability of our network, which requires that we prudently and efficiently invest in the following activities:

- Routine maintenance (including vegetation management)
- Emergency response
- Condition-based maintenance
- SCADA/Network control, and
- Other maintenance.

15. We also incur opex on support and operating activities, such as:

- Network operating costs—examples include faults and emergency support, SCADA service monitoring, control room, internal standards or policy development, asset regulatory and safety compliance, corporate overheads and land tax
- Regulatory costs, corporate overheads (including information technology), and

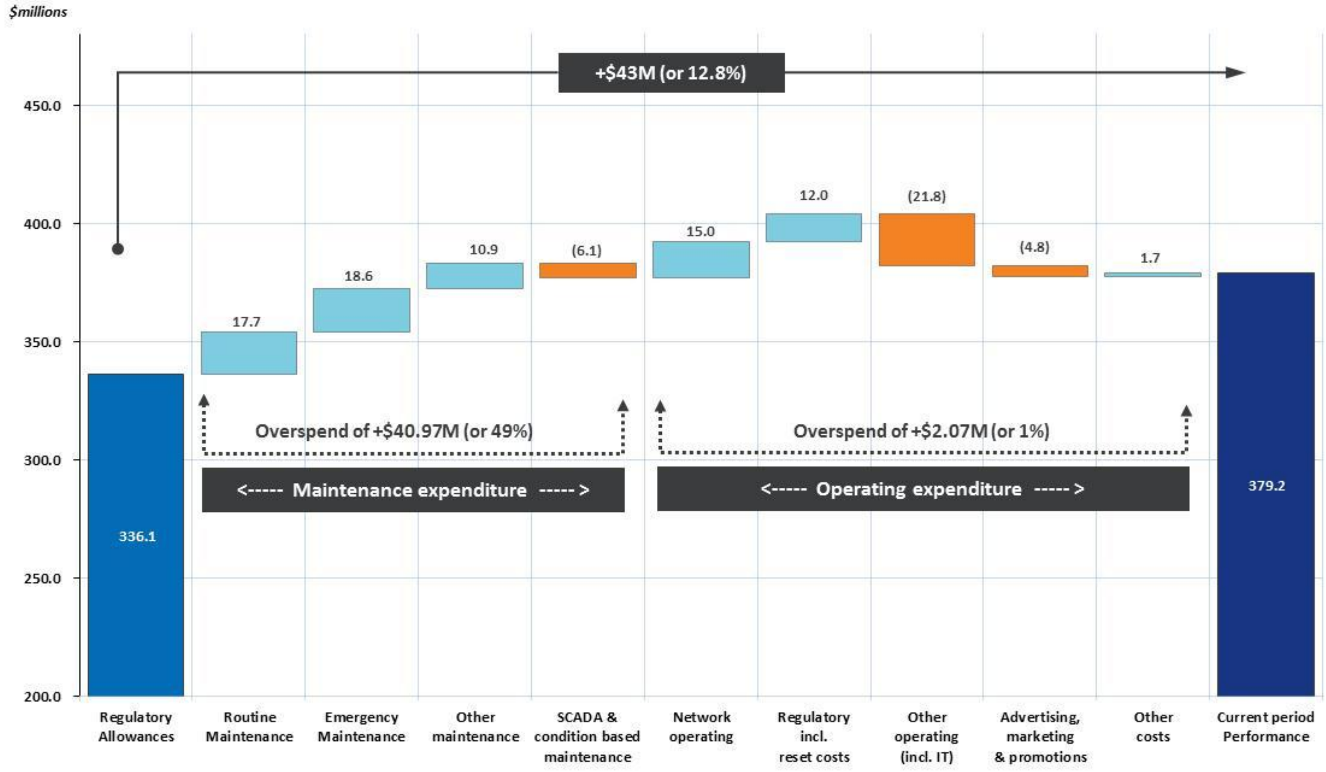
[4] *Productive (or technical efficiency*) means that electricity services are produced at minimum cost, using the least-cost combination of inputs. *Allocative efficiency* means that the right amount of the right type of electricity service is produced and consumed, and resources cannot be reallocated in a manner that results in a higher valued bundle of outputs. *Dynamic efficiency* means that allocative and productive efficiency continues to be achieved over time.

- Billing and revenue collection, advertising, customer service, license fees, guaranteed service level (**GSL**) payments, demand side management, self-insurance and debt raising costs.

16. The handing back of back office functions (which we shared with UE via JAM) resulted in lost cost saving previously realised through synergies. This is reflected in a few opex categories, with the majority of dis-synergies experienced in the network operating area.

17. Key drivers of the unforeseen increase in opex are shown in **Figure 2–2.**

Figure 2–2: Key drivers of unforseen increase in opex to regulatory allowances ($2015, $millions)



(1) “Other costs” includes billing and revenue collection, customer service, license fees, GSL payments, demand side management, self-insurance and debt raising costs[5]. Amounts represent the five-year total expenditure over the 2011 regulatory period.

18. The key drivers contributing to the variance between actual (and expected) opex and the regulatory allowances are explained in detail in Table 2–2.

[5] JEN does not incur debt raising costs directly as these costs are incurred by JEN’s parent companies and the costs are not allocated to its subsidiary assets.

Table 2–2: Key drivers of unforseen increase in opex to regulatory allowances ($2015, $millions)

Opex category	Opex component	Comments
Maintenance expenditure (variance of +$41.0m)	Routine maintenance (variance of +$17.7m)	Variance due to new bushfire mitigation and compliance obligations—occurring after 2009 (the base year for the 2011 regulatory period)—mandated by ESV and VBRC (including the Bushfire Powerline Safety Task Force (**BPSTF**). Examples include: • Changes to the Electric Line Clearance Regulations (**ELCR**)[6], where these regulations determine our vegetation clearance obligations, including liaising with customers relating to services (defect process) and alternative solutions assessments • Introduction of a new dedicated hazardous tree assessment and cutting program in both rural and urban areas following the ELCR changes in 2010 • New communication and consultation requirements with Councils, where JEN is now required to prepare detailed monthly reports of vegetation induced electrical faults and organising monthly meetings • Cameras—elevated above the pole top using telescopic masts—to assist routine pole top asset inspection to improve the asset inspection quality, with photographs used on side by inspectors and recorded against the relevant asset in GIS • Additional steel conduction inspection requirements, in addition to routine asset inspection program, to assess all overhead high voltage conductors using the elevated camera technology • Inspection of the above ground part of underground distribution assets (e.g. kiosk, pad mount, indoor, ground mount), including identification of asbestos based on the OH&S Act and subordinate asbestos regulations, previously not required • Fire-factor (**F-factor**) monitoring and ESV auditing and investigations • Adoption of Australian standard 4373 requirements[7] for tree pruning to retain amenity • ESV outage reporting—requiring monthly reporting by council area from Jan 2013

[6] New ELCR was introduced in 2010, which represents additional requirement compared to the ECLR from 2005.

[7] This standard (issued by Standards Australia) specifies methods for pruning of trees and gives guidance on correct and uniform practices. It is intended to use on amenity trees, including palms, and includes removal of deadwood, crown lifting, formative pruning, reduction pruning (including line clearance), selective pruning, crown thinning and remedial or restorative pruning.

<table>
<tr><th>Opex category</th><th>Opex component</th><th>Comments</th></tr>
<tr><td></td><td>Emergency maintenance (variance of +$18.6m)</td><td>Variance due to:
Realigning our emergency management system (EMS) and response times in 2010, leading to higher faults and emergency costs, but a reduction in our response times in the field and improvements to our coordination centre
Unforeseen (or uncontrollable) major network events such as storm damage to our Broadmeadows field depot (in late 2011), separate pole fire events and significant wind storm events</td></tr>
<tr><td></td><td>Other maintenance
(variance of +$10.9m)</td><td>Variance due to:
Regulatory allowances did not include any opex for the ‘other maintenance’ category, however in our annual RIN reporting, we reported opex within this category
This opex relates to parts of back office functions such as faults and emergency call centre, network billing, new connections, meter data management, regulatory compliance and managing customer contact
These functions were present back in 2009 and costs for these functions were implicitly included in the 2011 regulatory period base year opex (i.e. 2009)
However, due to various changes in our Enterprise Resource Planning (ERP) system during the 2011 regulatory period, we are not in a position to split out these costs into the various detailed functions and assess the variances to our regulatory allowances</td></tr>
<tr><td></td><td>SCADA & condition based maintenance
(variance of -$6.1m)</td><td>Variance primarily due to:
Differences in length, duration and frequency of maintenance cycles at our zone substations resulting in lower volume of work required
Lower spend in other condition based maintenance activities such as asset performance monitoring and assessments, investigation of voltage complaints and low voltage or high voltage joint repairs</td></tr>
<tr><td>Operating expenditure (variance of +$2.1m)</td><td>Network operating costs
(variance of +$15.0m)</td><td>Variance due to:
Loss of synergies when JAM ceased providing asset management functions to UED, resulting in lost cost saving previously realised through synergies
Our commitment to meet the service levels our customers told us they value, spending more on:
Improving our control centre monitoring
Supervisory control and data acquisition (SCADA) system
Ensuring our asset regulatory technical compliance, and
Processes to improve our employees’ time writing quality to adequately capture costs by functional activity.</td></tr>
</table>

Opex category	Opex component	Comments
	Regulatory (variance of +$12.0m)	Variance due to: • Extensive increase in regulatory activity by policy makers, rule makers and regulators[8] • For instance, the AER has served JEN more onerous regulatory reporting requirements, through four additional regulatory information notices (**RINs**)—requiring significant additional resourcing efforts, external audits and associated costs.
	Other operating (including information technology) (variance of -$21.8m)	Following the challenges we faced, we took additional steps to respond to the EBSS incentives and stakeholders' pressures. Initiatives include: • Investment in our accounting systems as an enabler to promote process improvement and harness productivity across the business • Improvement in our governance framework (through obtaining accreditation to PAS 55—a world-class standard—that indicates we have sound processes in place to facilitate compliance with relevant governance frameworks • Review of the Enterprise Business Services (**EBS**) contract arrangement—which provided shared IT services to JEN and AusNet Services—delivering significant IT opex savings These cost initiatives are partially offset by the following: • No provision made in the regulatory allowance for the payment of Singapore Power (**SP**) shareholder management fees—to compensate our shareholders for overseeing and providing strategic guidance on the overall operation of our network—and related party margins
	Advertising, marketing & promotion (variance of -$4.8m)	Variance due to: • Lower spend in our customer charter and customer communications programs
	Other costs (variance of +$1.7m)	Variance due to differences in expenditure on activities such as : • Billing and revenue collection, customer service, license fees, guaranteed service level (**GSL**) payments or demand side management.

2.1.1 OUR BASE YEAR IS EFFICIENT

19. We engaged an independent expert consultant (Huegin) to assess our historical opex productivity over time, and determine whether our proposed base year is at an efficient level from which to forecast our proposed opex for the 2016 regulatory period.

20. In preparing our opex forecasts for the 2016 regulatory period, we propose 2014 as the base year and support the revealed cost approach because this is the latest available information at the time of preparing this regulatory proposal.

[8] For instance, the Energy Networks Association notes in its Media Release "*Senate Proposals Increase Risk And Energy Bills*, 20 April 2015"that "*the Senate proposals come when the regulator has not even finished its first round of reviews under the new regime, and the inquiry itself noted there have been 17 different reviews of energy network regulation since 2010.*"

21. Our analysis—supported by Huegin's expert advice—states that there is no sufficient evidence to suggest our revealed base year is not materially inefficient (see Attachment 8–5).

2.1.2 OUR RESPONSE TO INCENTIVES

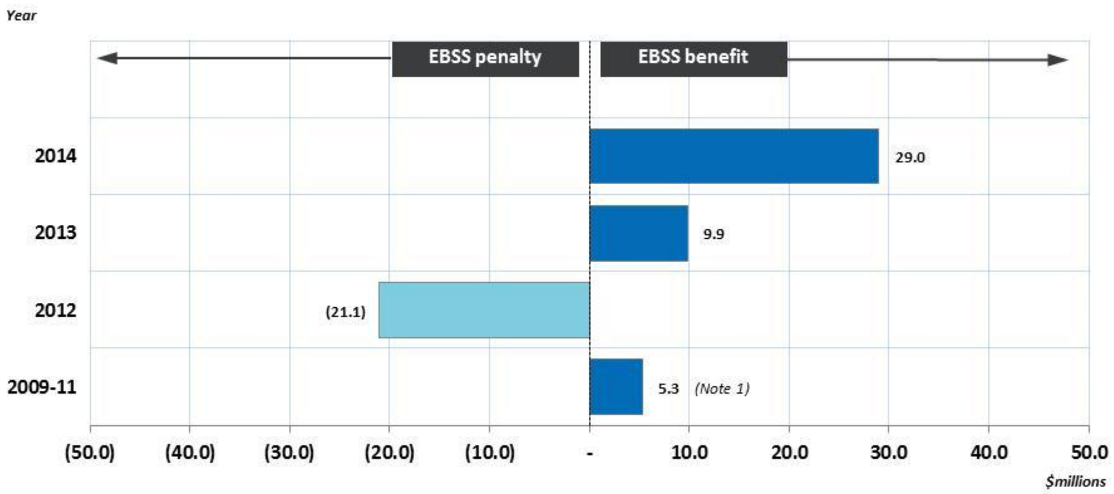
22. We propose to retain the EBSS, which drives opex efficiency, because we consider this is a powerful tool to incentivise network service providers to act in the long-term interests of consumers (see Attachment 5–3 for more detail).

23. Importantly, even in the absence of the EBSS, a prudent service network provider acting efficiently such as JEN is incentivised—through our private ownership and our customers' expectations—to manage and lower our opex over time through improved productivity.

24. Our proactive approach to respond to EBSS incentives and stakeholder pressures—highlighted from recurring opex reduction from 2013 onwards—results in an EBSS benefit of $23.1m ($2015), which will be shared with our customers over the 2016 regulatory period. Figure 2–3 sets out the EBSS outcome from our opex current period performance over 2009 to 2014.

25. For instance, the unforeseen opex increase in 2012 results in an EBSS penalty of $21.1m ($2015), followed by EBSS benefits of $9.9.m and $29.0m, resulting from our opex responses in 2013 and 2014.

Figure 2–3: EBSS expected outcome based on opex performances over 2011 to 2014 ($2015, $millions)



(1) The AER's most recent final decision for EBSS (dated June 2008) mechanism, now takes into account relative opex performances over 2009 to 2011 to estimate the incremental EBSS benefit/penalty in 2016.
(2) The EBSS benefit/penalty illustrates the outcome resulting from the opex performance in the relevant year (on the x-axis).
(3) The 2011 outcome takes into account our opex performance (against Essential Services Commission's approved allowances) over 2009 and 2010. The 2015 outcome will be reflected in 2021, because at the time of determination, the actual expenditure for 2015 is not readily available.

26. Figure 2–4 shows the annual EBSS benefits / (penalties) that will be shared with our customers over the 2016 regulatory period.

Figure 2–4: EBSS expected outcome over 2016–20 period ($2015, $millions)