The Australian Energy Regulator

Review of Proposed Expenditure of ACT & NSW Electricity DNSPs

Volume 2 – EnergyAustralia

Final

October 2008

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Engineering and Management Consultants

Advisers and Valuers

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Reply to: Auckland Office
Our ref: 0803
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21 November, 2008

Mr M Buckley,
General Manager,
Network Regulation North Branch
The Australian Energy Regulator
Marcus Clarke Street
CANBERRA ACT 2601

Dear Mr Buckley

REVIEW OF PROPOSED EXPENDITURE OF ACT & NSW ELECTRICITY DNSPS: VOLUME 2 – ENERGYAUSTRALIA

In response to your instructions, we have pleasure in presenting our assessment of the proposed expenditure of the ACT and NSW electricity distribution network service providers for your consideration as part of the revenue determination to be applied to their services from 1 July 2009 to 30 June 2014.

This volume covers the assessment of EnergyAustralia's expenditure and is to be read in conjunction with volume 1, which deals with general and methodological matters relating to the work and common to all DNSPs.

In summary, the key issues and conclusions from our review are as follows.

(a) EnergyAustralia will over-spend against the IPART distribution and ACCC transmission determinations in both opex and capex in the current period. The principal reasons given by EnergyAustralia were real cost increases in both labour and materials and the need to carry out more work than allowed for in the determinations.

(b) EnergyAustralia's proposed capex and opex from 1 July 2009 to 30 June 2014 are both substantially above the levels in the current period. The reasons for the increases are a combination of real escalation in the cost of labour and materials and an increased scope of work to be performed.

(c) In respect of capex, the increase in the scope of work is driven by four principal factors: growth in demand, the need to comply with the NSW licence conditions for supply security and reliability, the need to address deferred 11 kV work and the need to increase the rate of replacement of aged network assets, many of which are now at the end of or beyond their prudent engineering lives and are presenting in many cases an unacceptable safety and supply risk. We have concluded that the capex programme proposed is reasonable in both scope and cost.

(d) The increase in the scope of opex is driven partly by increases in maintenance costs resulting from an increase in the volume of assets in service and their continued aging but to a much larger degree by increases in business and network support costs. We have not been convinced of the need for such large increases in these support costs and consider that EnergyAustralia should be able to achieve efficiencies within the business from its investments in IT systems and property, and from other improvement initiatives to offset many of the incremental costs it claims it will face. We have therefore concluded that some adjustment is required to bring its opex to a more reasonable level.

Our opinion is summarised in section 11 of the report, along with other matters that we would like to bring to your attention.

In conclusion, we acknowledge with thanks the assistance and cooperation of the AER and EnergyAustralia in the preparation of this report.

Yours faithfully,

Wilson Cook & Co Limited

Wilson Cook & Co.

Encl.

Review of Proposed Expenditure of ACT & NSW Electricity DNSPs

Volume 2 – EnergyAustralia

Final

Prepared for the Australian Energy Regulator

By Wilson Cook & Co Limited

Enquiries to Mr J W Wilson

Our reference 0803

October 2008

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Disclosure

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to us. No responsibility is accepted if full disclosure has not been made. We do not accept responsibility for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied.

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1 Introduction

1.1 Scope of this Volume

In this volume of our report, volume 2, we review the proposed expenditure of EnergyAustralia for the AER's consideration as part of the revenue determination to be applied to the services provided by ACT and NSW electricity distribution network service providers from 1 July 2009 to 30 June 2014. The volume is presented in eleven main sections:

Section 1	Introduction (this section)
Section 2	Background
Section 3	Capex in Current Period
Section 4	Capex in Next Period
Section 5	Growth Capex
Section 6	Replacement Capex
Section 7	System Capex
Section 8	Non-System Capex
Section 9	Opex
Section 10	Other Matters
Section 11	Conclusion and Recommendations.

1.2 Basis of the Review

Unless noted otherwise, the review is based on the proposals and submissions presented by EnergyAustralia to the AER and on supplementary information prepared by EnergyAustralia and submitted to the AER and us.

1.3 Particular Issues Considered

Particular issues considered in the review included identification of the basis of the forecasts in each expenditure category, consideration of the main expenditure drivers, identification of the impact of external factors, review of the impact of cost escalation and the treatment of forecast future real increases in costs, review of the efficiency of the estimated costs (and of unit costs where relevant) and consideration of the adequacy, efficiency and application of the DNSP's policies and procedures.

The tests applied were the tests required by the transitional Rules, as explained in volume 1 of this report.

1.4 Report to be Read in Conjunction with Volume 1

This volume of the report is to be read in conjunction with volume 1 of our report, which deals with general and methodological matters relating to the work and with matters that are common to all DNSPs.

The abbreviations and terms used are those in volume 1.

Unless noted otherwise, all sums are stated in real 2009 dollars.

Tables adjusted to 2009 dollars have all been adjusted using the Australian Bureau of Statistics' annual consumer price index (CPI) data for all Australian capital cities for the years ending 30 June.

1.5 Terms, Conditions and Disclaimers

This volume of the report is subject to the terms, conditions and disclaimers set out in section 11.3 below.

1.6 Acknowledgement

We acknowledge with thanks the assistance and cooperation of EnergyAustralia and the AER in the preparation of this volume of the report.

2 Background

2.1 Business Profile

EnergyAustralia owns, manages and operates distribution and transmission networks in Greater Sydney, Newcastle, the Hunter Valley and the Central Coast. It was formed in the electricity sector restructuring in NSW in the 1990s by a merger of Sydney Electricity and Orion Energy in Newcastle. There have been no changes to EnergyAustralia's composition since that time.

2.2 Network Features

Before proceeding to identify and review the proposed expenditure, we first considered the network characteristics most relevant to our work and noted the following points.[1]

(a) The main network regions are Sydney, the Central Coast and the Hunter valley.
(b) Transmission is at 132 kV and 66 kV: it operates in support of TransGrid's network in central Sydney, the Central Coast and the Hunter valley.
(c) Sydney is supplied at 132 kV from the Beaconsfield West, Haymarket, Sydney East, Sydney North and Sydney South bulk supply points. Beaconsfield West and Haymarket each take supply at 330 kV via single 330 kV cables. [2]
(d) The Central Coast region is supplied at 132 kV from the Munmorah, Sydney North, Tuggerah and Vales Point bulk supply points. Tuggerah and Munmorah are of a single transformer configuration. [3]
(e) The Hunter valley is supplied at 132 kV from the Muswellbrook, Newcastle and Waratah West bulk supply points.
(f) Sub-transmission is at 132 kV, 66 kV and 33 kV and distribution is at 22 kV, 11 kV, 5 kV and low voltage.
(g) Designs at each voltage level appear to be conventional.
(h) The physical condition of the network is understood to be commensurate with age.

The key network statistics are shown in Table 2.1.

Table 2.1: Key Network Statistics

Service area (sq km)	22,275
Transmission system length (km)	3,800
HV distribution system length (km)	16,900
LV distribution system length (km)	27,890
Percent of network underground	28%
Transmission substations	39
Zone substations	177
Distribution substations	29,180

1 A description of the network can be found in the company's documents.

2 A point of bulk supply is to be added at Chullora by TransGrid during the next period and a further point is to be added at Surry Hills after 2014.

3 A second transformer is being added at Tuggerah by TransGrid.

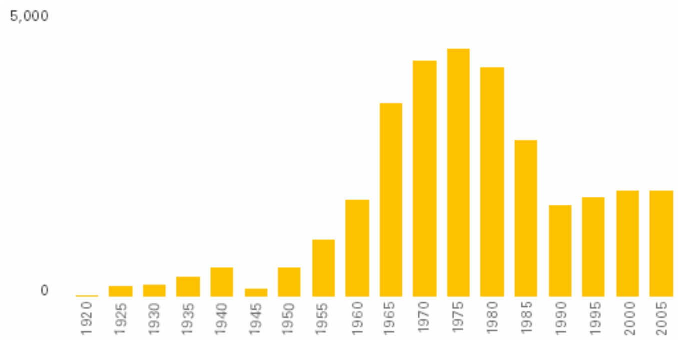
Poles	493,501
Total customers	1,568,308
Maximum peak demand (MW)	5,636

Source: EnergyAustralia.

Age Profile

An indicative profile of the age of the assets is shown in the graph of asset replacement cost *vs*. year in Figure 2.1. The figure, which is plotted by replacement value in millions of FY 2009 dollars, shows that there are a notable quantity of very old assets installed before 1960 and a heavy weighting of assets installed in the period 1960 to 1985.

Figure 2.1: Indicative Age Profile of the Assets



Source: EnergyAustralia.

Table 2.2 shows the age of assets in the main categories and confirms that EnergyAustralia's network assets are quite aged across a wide front with several major asset categories having average ages in excess of two-thirds of their standard life, suggesting that high levels of replacement capex should be anticipated.

Table 2.2: Age of Main Asset Categories

Asset Category	Standard Life a/ (years)	Age as pct of Life
132 kV OH circuits steel tower lines	60	66%
132 kV OH circuits steel towers	60	68%
132 kV OH circuits wood and concrete	45	71%
66 kV OH circuits	45	62%
33 kV OH circuits	45	80%
11/22 kV OH circuits b/	45	62%
LV OH circuits b/	45	69%
132 kV UG circuits	45	70%
66 kV UG circuits	45	87%
33 kV UG circuits	45	103%
11/22 kV UG circuits b/	60	51%
LV UG circuits b/	60	42%
Sub-transmission substations	60	63%

Large switching stations	60	72%
Small switching stations	60	49%
Zone substations	60	59%
132 kV circuit breakers	45	49%
66 kV circuit breakers	45	43%
33 kV circuit breakers	45	79%
11/22 kV circuit breakers	45	73%
Sub-transmission transformers	50	70%
132/11 kV zone transformers	50	36%
66/11 kV zone transformers	50	62%
33/11 kV zone transformers	50	65%
Distribution centres (substations) b/	40	63%
Distribution transformers	45	53%
Services overhead	35	88%
Services underground	60	41%
Connections	45	67%
Low voltage pillars	45	32%
Streetlights	20	130%

Source: EnergyAustralia.
a/ Standard life as used by EnergyAustralia.
b/ EnergyAustralia does not have full records on the age of its distribution mains.

EnergyAustralia rightly notes in its proposal that a high proportion of aged assets can present a substantial risk to a network and that whilst prudent management and condition monitoring enables many assets to be kept in service beyond their design life, the matter still needs to be addressed. Its proposal includes the prioritised replacement of some assets on a condition basis in cases where EnergyAustralia faces the risk that the failure rate for an asset category could overtake its capacity to respond without severe impacts on network performance in future periods. Special attention is also given to highly loaded assets needing replacement as their replacement is only possible in the autumn and spring low-load months and the replacement programmes will take many years to complete.

Notwithstanding this investment, the weighted average age of the network is predicted to keep increasing, albeit at a lower rate over the next period.

Network Performance

Reliability

Network reliability in terms of SAIDI is shown in Table 2.3. The table shows a mixed performance over the period.

Table 2.3: Network Reliability – SAIDI a/

YE 30 June	2003	2004	2005	2006	Average
CBD feeders	49	106	9	13	40
Urban feeders	66	75	76	69	73
Short-rural feeders	288	351	245	341	303
Long-rural feeders	481	818	953	342	691

Overall	84	99	90	91	92

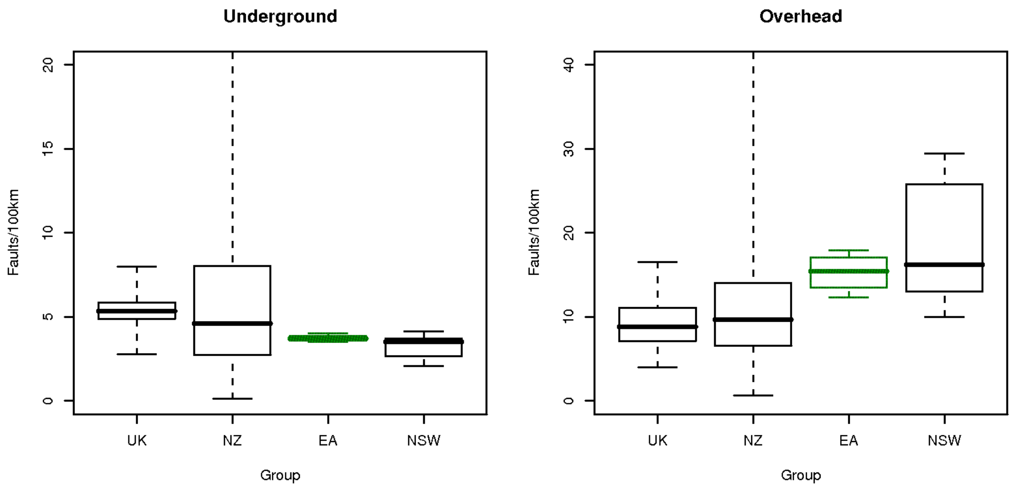
Source: EnergyAustralia.
a/ Major event days, planned interruptions and interruptions resulting from load shedding excluded.

Details of the network's performance are given in the reliability management plan, submitted with EnergyAustralia's proposal, from which we noted that, in FY 2006, SAIDI was within the standard set by the licence conditions in all feeder categories. [4]

Fault Rates (HV Distribution Mains)

Network performance in terms of fault rates per circuit-km p.a. for EnergyAustralia's high voltage distribution mains is shown in Figure 2.2. [5] [6] [7] The figure shows (within the limits of such analysis) that EnergyAustralia's fault rate for underground circuits compares well to New Zealand, UK and other NSW DNSPs but the performance of its overhead circuits is worse than reported in the New Zealand and UK top quartiles but below the median for the NSW DNSPs.

Figure 2.2: HV Distribution Mains Fault Rates in Comparison with Other DNSPs



If fault classifications other than "condition" are removed, EnergyAustralia's position is as shown in Table 2.4. The table shows mixed results for underground HV mains, a rising trend for underground LV mains and a generally falling trend for overhead mains. The susceptibility of overhead mains to faults as implied by the fault rate comparison in Figure 2.2 and the rising fault trend in the low voltage underground circuits as implied by the figures in Table 2.4 lends weight to EnergyAustralia's forecast expenditure in these areas.

4 The NSW licence conditions for reliability and security of supply, as amended in December 2007.

5 Sources: published data from the Office of Electricity and Gas Markets in the UK for the period 2002 to 2006; published data in respect of New Zealand lines businesses for 11 kV distribution circuits for the period 1998 to 2007 (may include 22 kV and 6.6 kV distribution circuits); and data from the NSW DNSPs supplied for the purpose of this review. The boxes show the upper and lower quartiles about the marked median value. The wide range of the data in the New Zealand case reflects the large number of companies involved (around 30) compared with the small number of companies in the UK.

6 The statistics are for faults from all causes.

7 We prefer the analysis of fault rates when considering the robustness of replacement expenditure projections, as they are more indicative of condition than customer performance indices such as SAIDI, which are affected by other factors and disguised to a degree by the removal of adverse weather events, the withstanding of which are a normal requirement of networks. (It is admitted that fault rates are also influenced by factors other than condition, e.g. by vegetation management and motor vehicle accidents, but in respect of storm damage they do reflect the robustness of the circuits and implicitly their general condition.)

Table 2.4: HV Distribution Mains Faults Attributable to Condition

YE 30 June	2004	2005	2006	2007
HV underground mains	197	187	190	235
LV underground mains	469	541	543	726
HV overhead mains	105	90	87	72
LV overhead mains	439	427	361	299

Source: EnergyAustralia.

2.3 Summary of Expenditure Proposed

Table 2.5 summarises the combined transmission and distribution expenditure proposed in the next period. EnergyAustralia has proposed capex and opex of $8,658 m and $2,972 m respectively. This represents an increase of approximately $4,733 m or 121% over the current period for capex and an increase of $827 m or 39% over the current period for opex.

Table 2.5: Expenditure Proposed ($m 2009)

Period (FYs)	**2005-09**	**2010-14**
Capex a/	3,925	8,658
Opex b/	2,146	2,972

Source: EnergyAustralia. Includes modifications to the RIN template up to 19 July 2008.
a/ Excluding expenditure funded by customer capital contributions.
b/ FY 2010-14 opex excludes approximately $100 m of debt raising and equity raising costs.

These proposed expenditures are analysed in the following sections of the report, after first briefly reviewing EnergyAustralia's capex in the current period against the determinations.

3 Capex in Current Period

3.1 Summary of Expenditure

Table 3.1 summarises EnergyAustralia's transmission and distribution capex in the current period and compares it with the expenditure in the determinations plus pass-through expenditure agreed to date.

Table 3.1: Capex in Current Period *vs.* Determinations ($ m nominal) a/

Distribution

	Actual			Estimated		Total
YE 30 June	2005	2006	2007	2008	2009	
Determination (IPART)	403	411	420	421	441	2,097
Pass-through expenditure	0	53	194	204	202	653
Capex in current period	420	535	717	825	894	3,390
Over-run / (under-run)	**17**	**71**	**102**	**199**	**251**	**640**
Over-run / (under-run) (%)	4%	15%	17%	32%	39%	23%

Source: EnergyAustralia.
a/ Net of work funded by customer capital contributions.

Transmission

	Actual			Estimated		Total
YE 30 June	2005	2006	2007	2008	2009	
Determination (ACCC)	50	34	67	64	48	262
Pass-through expenditure	0	0	0	0	0	0
Capex in current period	38	43	39	53	161	334
Over-run / (under-run)	**(12)**	**9**	**(27)**	**(11)**	**113**	**72**
Over-run / (under-run) (%)	(24%)	28%	(41%)	(17%)	235%	28%

Source: EnergyAustralia.

The table shows that EnergyAustralia's distribution capex is projected to be $640 m, or 23% over the level allowed by IPART and its transmission capex is projected to be $72 m, or 28% over the level allowed by the ACCC. [8] EnergyAustralia attributes the main drivers of the over-spending to cost escalation, a carry-over of work from the previous period, accounting policy changes and adjustments that had resulted in the capitalisation of $114 m of expenditure on pole replacements, acceleration or inclusion of new projects work programmes and changes in the planned scope of work undertaken.

Details of the key variances are given in EnergyAustralia's proposal and the associated documents, from which Figure 3.1 is taken. [9]

EnergyAustralia stated that the largest category of over-expenditure was replacement and it noted that both IPART and the ACCC had reduced its proposed replacement programmes in

[8] In commenting on the draft report, EnergyAustralia said that the transmission determination figures in Table 3.1 do not include the AER's contingent project allowance decision of July 2008.

[9] See in particular the documents *"Comparison of actual capital investment with regulatory determinations"* and attachment 11.1 *"EnergyAustralia: variations between forecast and historic expenditure"*.

their last determinations. [10] It said that despite this, it had spent $357 m more than its allowance in replacement and that that had been driven by reactive replacement and a growing programme to remove poorly performing equipment. In addition, expenditure on major replacement projects has increased because of scope and cost input changes as well as a carry-over of projects from the previous period.

It said that strategic system property acquisition has also been a major contributor to the over-expenditure but that the purchases were necessary for planned capital works in the next period.

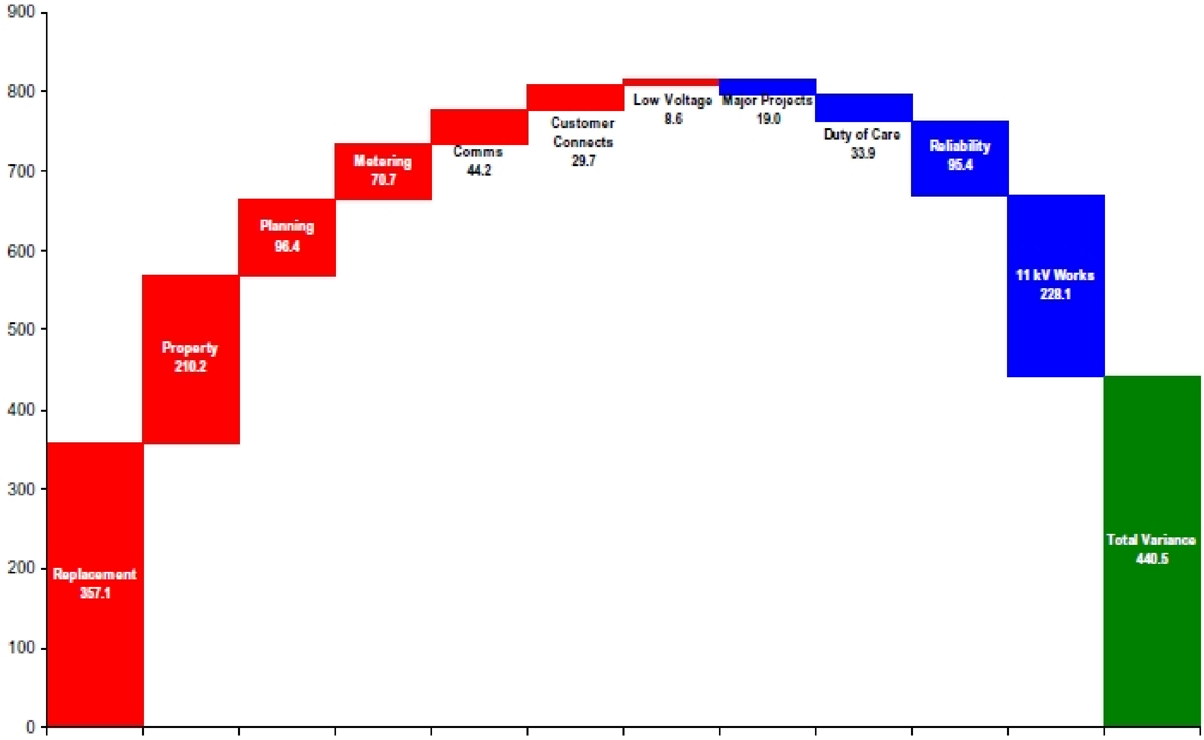
It said that changes to the scope of its programmes had occurred in metering, customer connections and major replacement works.

It said that expenditure on 11 kV works including reliability-based investments was likely to be lower than the allowance due mainly to a lack of resources.

It said that it had taken steps to improve its forecast accuracy for the next period to avoid a recurrence of the situation in 2014.

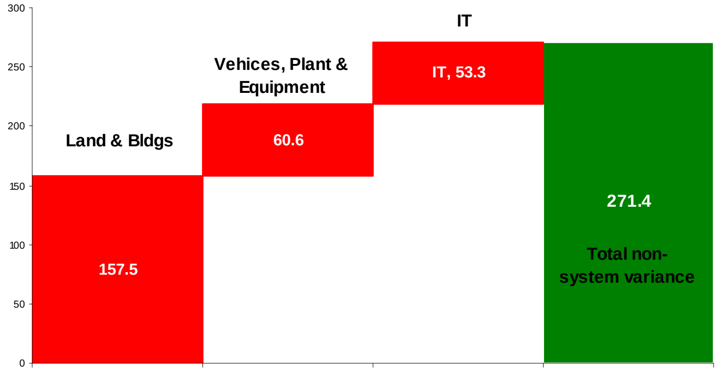
Figure 3.1: Variances between Actual Expenditure and Determination ($ m)

System Assets



[10] Obviously, both IPART and the ACCC considered that they had reason for the reductions.

Non-System Assets



We noted the variances and the points mentioned above when carrying out our analysis of the capex proposed for the next period and, in that context, considered the reasonableness of the variances from the standpoint of their allocation and consistency with the case made by EnergyAustralia for expenditure in the next period. Under the heading of system assets, we considered that the allocation of additional resources to replacement and property for new substations at the expense of 11 kV work was reasonable and we had no comment on the other reallocations. Under the heading of non-system assets, we considered that the additional expenditure on land and buildings (which was mainly related accommodating additional staff and rationalising field depots and other facilities) was reasonable and we had no comment on the other variances.

We did not review EnergyAustralia’s capex in the current period further, given a review of its prudence was not required.

4 Capex in Next Period

4.1 Summary of Proposed Expenditure

Table 4.1 summarises the capex proposed in the next period in comparison with that in the current period.

Table 4.1: Current and Forecast Capex ($ m 2009) a/

Distribution

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
System assets:												
Asset renewal/replacement	156	210	266	272	320	467	573	636	645	779	3,101	42%
Growth (demand related) a/	212	260	389	406	368	498	582	604	560	537	2,781	38%
Reliability and quality of service enhancement	9	11	11	14	12	52	78	133	68	35	367	5%
Environmental, safety, statutory obligations	53	43	36	31	29	61	58	95	102	76	390	5%
Other	0	0	0	0	0	34	27	35	22	23	141	2%
	431	**524**	**702**	**724**	**729**	**1112**	**1318**	**1504**	**1397**	**1449**	6,780	93%
Non-system assets	49	62	68	124	165	196	102	98	76	73	545	7%
	479	**586**	**770**	**848**	**894**	**1308**	**1420**	**1602**	**1473**	**1522**	7,326	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.
a/ Net of work funded by customer capital contributions.

Transmission

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
System assets:												
Augmentation	20	12	8	11	69	75	81	65	80	90	390	29%
Replacement	16	25	24	26	68	163	66	134	171	93	627	47%
Reliability	0	0	0	0	0	2	1	45	83	40	171	13%
Compliance	1	1	0	0	0	9	21	19	12	8	69	5%
	36	**38**	**33**	**37**	**137**	**249**	**169**	**263**	**347**	**230**	1,257	94%
Non-system assets	7	9	10	18	23	27	14	13	10	10	75	6%
	43	**47**	**42**	**55**	**161**	**275**	**183**	**276**	**357**	**240**	1,332	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.

Total

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
System assets:												
Asset renewal/replacement	173	235	290	298	388	631	639	770	816	872	3,728	43%
Growth (demand related) a/	232	272	397	417	437	573	664	669	640	626	3,171	37%
Reliability and quality of service enhancement	9	11	11	14	12	54	79	178	152	74	538	6%
Environmental, safety, statutory obligations	54	45	37	31	29	69	79	114	114	84	460	5%
Other	0	0	0	0	0	34	27	35	22	23	141	2%
	467	**563**	**735**	**761**	**866**	**1361**	**1487**	**1767**	**1743**	**1679**	8,038	93%
Non-system assets	56	71	77	142	188	223	116	111	87	83	620	7%
	522	**634**	**812**	**902**	**1055**	**1584**	**1603**	**1878**	**1830**	**1762**	8,658	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments made after that date.
a/ Net of work funded by customer capital contributions.

The total expenditure proposed for both transmission and distribution including non-system assets is $8,658 m, compared with an estimated $3,925 m in the current period, an increase of 121%. The biggest area of expenditure is on replacement, followed by growth. Together, they account for 80% of the distribution capex and 76% of the transmission capex proposed and are discussed in sections 5 and 6 of this report. The other expenditure categories are discussed in section 7, before we conclude our review of system capex in the next period as a whole. Non-system capex is reviewed in section 8.

Table 4.2 shows the system asset component of the expenditure, allocated by asset type (a similar table is given in section 8.1 of the report for non-system assets). The table shows that distribution system capex is allocated mainly to zone substations (31%), distribution circuits (31%) and sub-transmission circuits (15%) with the remaining 23% spread across the other asset categories. The majority of transmission system capex is allocated to zone substations (37%), underground sub-transmission feeders (35%) and sub-transmission substations (11%).

Table 4.2: Current and Forecast Capex on System Assets by Type ($ m 2009) a/

Distribution

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
Sub-transmission substations	9	17	26	43	3	46	21	8	29	35	139	2%
Zone substations	95	113	112	151	274	347	467	483	432	403	2,132	31%
Distribution substations	43	56	56	54	74	55	75	107	96	103	436	6%
Distribution transformers	25	32	40	19	20	17	23	32	29	31	132	2%
Sub-transmission lines and cables	61	70	96	114	28	181	142	201	221	277	1,022	15%
Distribution lines and cables	119	177	212	219	226	260	359	509	456	489	2,074	31%
Customer metering and load control	28	29	31	28	43	35	26	23	23	23	130	2%
Communications	13	13	28	38	22	5	5	10	7	1	28	0%
Land and easements	32	10	95	58	39	72	76	13	3	5	169	2%
Other system assets	4	8	6	0	0	94	123	118	101	82	518	8%
	431	**524**	**702**	**724**	**729**	**1112**	**1318**	**1504**	**1397**	**1449**	6,780	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.
a/ Net of work funded by customer capital contributions.

Transmission

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
Sub-transmission substations	10	9	16	17	30	38	28	20	22	30	137	11%
Zone substations	12	10	2	9	7	57	64	95	158	96	470	37%
Underground sub-transmission feeders	6	6	3	6	49	103	37	114	124	56	434	35%
Overhead sub-transmission feeders	2	7	2	3	1	21	13	8	13	12	67	5%
Land and easements	4	2	8	1	50	6	1	1	4	1	13	1%
Load control and communications	2	4	2	0	0	5	2	1	1	1	10	1%
Other system assets	0	0	0	0	0	19	25	22	26	34	126	10%
	36	**38**	**33**	**37**	**138**	**249**	**169**	**263**	**347**	**230**	1,257	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.

4.2 Basis of Expenditure Forecasts

The basis of the expenditure forecasts is set out in EnergyAustralia's proposal and its various plans, listed in Table 4.3. EnergyAustralia says that the key drivers of investment in the network over the next period are:

- continued growth in peak demand,
- the need to comply with the licence conditions for reliability and security of supply,[11]
- the replacement of aging assets, and
- the deferral of over $200 m in capex on 11 kV works from the current period.

Capex is projected to include significant transmission and sub-transmission investment for additional capacity to meet demand growth and replacement needs including a major reinforcement programme for the CBD and a total of 44 new zone substations, the retirement of 32 old zone substations, a large replacement capex programme for work in addition to the projects included in the area plans and a programme of work on the distribution network.

The replacement programme includes the replacement of a significant proportion of compound-filled 11 kV switchgear, 33 kV gas-filled cables and 132 kV oil-filled cables to improve transmission and sub-transmission network security and manage risk.

Planning at the transmission level is undertaken jointly with TransGrid.

EnergyAustralia has noted that its system load factor is deteriorating and that although demand management has assisted in deferring capital work to a limited extent in the current period, a significant supply-side response is required over the next period. [12]

4.3 Assessment Categories

EnergyAustralia has developed its capex forecasts from twenty-five area plans, three sub-transmission plans and various other plans, models and supporting documents that follow its own structure, not necessarily the framework used in the RIN templates as reflected in Table 4.1 above. For practical reasons, our analysis has been matched to the information provided by EnergyAustralia, rather than to the categories in the RIN templates. We considered that we had no choice but to analyse it that way as the supporting information was provided in a form that could be reconciled only with that breakdown. We requested details of the allocation of expenditure by the categories in the RIN templates but it was not provided to the extent required for analysis, only in the form of a high-level reconciliation that showed the totals matched. [13] Table 4.3 summarises the reconciliation provided and shows the connection between the expenditure as stated in the RIN templates and that developed in the various plans and other documents that we reviewed. [14] [15]

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[11] The document "*Cost impact of licence conditions*", EnergyAustralia, May 2008, summarises the impact of the licence conditions as: CBD (n-2) compliance, $332.8 m; 11 kV system compliance, $388.9 m; distribution substation compliance, $76.4m giving a total design planning criteria capex impact of $798.1 m; reliability standards, $29.6 m of capex; individual feeder reliability standards, $33.1 m of capex; and customer service standards, $2.5 m of opex.

[12] An assessment of the capex deferred by demand management measures and the potential impact of such measures on capex in the next period is given in EnergyAustralia's report *"DM impact on 2009-14 capital forecast*", EnergyAustralia, April 2008 (attachment 5.13 to the proposal).

[13] Clearly, EnergyAustralia itself had to make some of the allocations arbitrarily (although with the exercise of judgement) as much of the expenditure in the various plans and programmes was attributable to several drivers.

[14] These documents include three transmission area plans, twenty-five sub-transmission area plans, various replacement plans, a reliability investment plan, a "duty of care" plan (which covers environmental- and safety-related work), a customer connections plan, an 11 kV network development model, a low voltage capacity plan, a network communications and technology plan and documents setting out business support investment requirements.

[15] In commenting on our draft report, EnergyAustralia noted that it was not required to present its supporting information in line with the RIN categories.

Table 4.3: Reconciliation of Plans with RIN Expenditure Categories ($ m 2009) a/

	Growth b/	Replacement c/	Reliability	Compliance	Other d/	Non-system	Total
Area plans	1,523	1,634	459	165			3,781
Property plan e/	26	143					169
Replacement plan		1,828					1,828
Duty of care plan				285			285
Reliability plan			79				79
11kV network development	698						698
Low voltage capacity plan	295						295
Customer connections plan	504						504
System & bus. support plans f/	121	121			151	620	1,012
	3,168	**3,725**	**538**	**450**	**151**	**620**	8,651

Source: EnergyAustralia with adjustments by Wilson Cook & Co to reconcile with EA's RIN template of 19 July 2008.

a/ There is a discrepency of $7 m with the RIN template dated 19 July 2008. In addition, Compliance and Other are $10 m lower and higher, respectively.

b/ Area plans include $34 m of transmission connection capex under the growth heading.

c/ System and business support plan costs have been applied equally to growth and replacement.

d/ Comprised of metering and system IT.

e/ An error in EnergyAustralia's allocation in its source workbook has been corrected by Wilson Cook & Co.

f/ System & business support plans include an allocation of other wages, GIS, communications, demand management development and deferral and intelligent networks expenditure.

EnergyAustralia’s planning methodology and explanations for most of the forecast expenditure are summarised in the various plans.

5 Growth Capex

5.1 Summary of Proposed Expenditure

Table 5.1 summarises the growth capex proposed in the next period. Expenditure under this heading constitutes 37% of the total capex proposed.

Table 5.1: Forecast Growth Capex ($ m 2009) a/

YE 30 June	2010	2011	2012	2013	2014	Total	Pct of Total
Area plans	337	359	299	270	257	1,523	48%
11kV network development model	59	110	167	172	190	698	22%
Customer connections plan	90	101	102	104	107	504	16%
Low voltage capacity plan	52	54	62	63	63	295	9%
Property plan	7	12	7	0	0	26	1%
Other b/	26	27	31	29	8	121	4%
	572	**663**	**668**	**639**	**625**	3,167	100%

Source: EnergyAustralia with adjustments by Wilson Cook & Co to reconcile with EA's RIN template of 19 July 2008.
a/ There is a discrepency of $4 m with the RIN template.
b/ Allocation of other wages, GIS, communications, demand management development and deferral and intelligent networks expenditure.

The total expenditure proposed is $3,167 m, compared with an estimated $1,756 m in the current period, an increase of 81%.

The table shows that 48% of the proposed expenditure is attributable to the area plans, 22% to the 11 kV network development model, 16% to the customer connections plan and the remaining 14% to the low voltage capacity plan (9%), other expenditure (4%) and the property plan (1%). We discuss the expenditure by category in section 5.3.

5.2 Expenditure Drivers

Demand Forecast

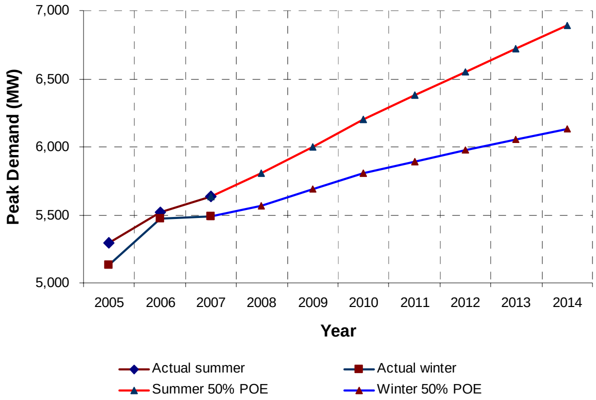
Increasing demand is the primary determinant of capex under the heading of growth. We noted that EnergyAustralia had produced its own demand forecast for the next period and had had it verified by Charles River Associates. A review of the forecast was outside our terms of reference but we noted that it exhibited continued growth, as shown in Figure 5.1.

We noted that the maximum system demand is forecast to grow at an annual rate of 2.8% over the next period and that the network continues to shift from winter peaking to summer peaking. [16]

We also noted that EnergyAustralia's capex programme is based on a "50% probability-of-exceedance" forecast. [17]

[16] EnergyAustralia says that at the beginning of the current period, 50% of its zone substations were summer peaking and by the end of the next period, about 77% will be summer peaking. This is important as in summer the network has less load-carrying capacity than in winter.

Figure 5.1: Forecast Growth in Maximum Demand



Security of Supply Criteria

Secondary determinants of demand-driven capex are the security of supply criteria assumed. In NSW, these are mandated in respect of the *distribution* system by the licence conditions. In essence, the licence conditions require an (n-1) security level to be attained at all zone substations serving demands over certain thresholds set out in the conditions, an (n-2) level to be attained in the CBD and feeder loads not to exceed a certain percentage of their rated capacity. [18]

Criteria for jointly planned *transmission* projects are as agreed with TransGrid and constitute, for the inner-metropolitan system, a modified (n-2) approach in which EnergyAustralia's network supports TransGrid's transmission circuits, particularly in respect of the two single radial feeders serving Beaconsfield West and Haymarket.

Plant Ratings

Plant ratings are a further determinant of demand-driven capex. We were satisfied that EnergyAustralia calculates its plant ratings for transformers and cables in accordance with accepted international standards and that the underlying assumptions made were reasonable.[19]

We noted that cyclic plant ratings are used in parallel with the 50% probability-of-exceedance demand forecast and considered that combination reasonable for planning purposes.

5.3 Review by Category

Growth-Related Expenditure in Area Plans

Area Plans and Planning Methodology

Approximately 48% of the proposed growth capex is attributable to the capital works described in EnergyAustralia's area plans. Each plan reviews the network and forecast

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[17] Our expenditure review assumes in essence that the forecasting methodology was sound, the forecast had been developed from feeder load data assuming a normal weather year, adjustments had been made to remove the effects of inter-feeder load transfers, large load additions had been considered in parallel with the determination of growth trends, the effects of any newly-installed power factor correction equipment had been taken into account along with any other relevant factors and thus that the forecast was suitable for use for network planning purposes.

[18] The planning design criteria stipulate an (n-1) design for urban 11 kV networks, which is extrapolated in the notes to the criteria as an average feeder utilisation target of 80% by FY 2014, reducing to 75% by FY 2019. Reference should be made to the conditions themselves for the full wording of all requirements.

[19] These were reviewed by Meritec at the time of the last determination and have not been changed.

demand in a defined area, briefly discusses demand management possibilities, takes account of committed projects, considers development alternatives for the area and sets out the proposed strategy and its estimated cost. [20] The plans do not purport to be detailed engineering assessments but are high-level summaries of the matters considered and conclusions reached in respect of each area and part of the transmission system. However, they are supported by reports on specific projects and programmes, including some or all of the following documents depending on the circumstances: application notices, consultation notices and final reports.

The area plans are accompanied by two other key plans, for replacement of 11 kV switchgear and replacement of sub-transmission feeders.

Together, these plans describe the strategies proposed to achieve compliance with the licence conditions and meet the replacement priorities for the switchgear and sub-transmission feeders. EnergyAustralia has stated that meeting these objectives fully would require a substantial increase in capex in the years up to FY 2012 including in the present period and amongst other things, it says that this is not practical from a resource perspective. It says that it has smoothed its capex profile to limit over-expenditure in the current period, keep the immediate rate of expenditure within the bounds of its present capability and ramp up the future levels in parallel with the introduction of new capex delivery mechanisms. It says that this has resulted in the deferral of $149 m of capex to beyond FY 2014.

EnergyAustralia acknowledges that demand management will accommodate part of this deferral but it says it is unable to identify specific projects that can be deferred because of it.[21] [22]

It says that its "smoothed" capex programme has been designed to meet the requirement of the licence conditions for compliance by the end of FY 2014 whilst minimising capex in the current period and ensuring a manageable programme for the next period. [23]

EnergyAustralia notes that the timing and cost of most of the major projects included in the capex forecast are accurately defined and can reasonably be included but that some projects are conditional: that is, they may be required because of third party requirements, major residential or customer developments, the accelerated replacement of equipment or for other reasons. It says that a probability of each project being triggered and capital expended within the next period has been assigned to each, based on available information, past history or experience. This probability is used to estimate an expected value for the conditional project. These projects are costed using EnergyAustralia's network development strategy costing model in the same way as other projects but their cost is then adjusted by the probability of the project proceeding. It says that the proposed capex programme includes some twenty conditional projects. [24]

It is recognised that the area plans are not a final statement of the works required in the sense that except in committed cases or those soon to be committed, the projects in the plans remain subject to final design and approval.

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[20] The planning and costing methodology is explained in various supporting documents, including the following attachments to EnergyAustralia's proposal: 5.03 (area plan development process), 5.04 (costing basis) and "capex modelling".

[21] It says that the projects deferred will be "low risk" projects, *viz.* low risk in terms of the likely impact on network performance in the next period.

[22] We noted that in each of the projects we reviewed, EnergyAustralia had analysed or is analysing the potential for demand-side management to deliver savings by deferring investment.

[23] Smoothing has been achieved by changing the completion dates of projects within the next period and by the deferrals discussed in the preceding paragraphs. The adjustments made are summarised in the report *"Project timeframe variation"* EnergyAustralia, May 2008 (attachment 5.13A to the proposal).

[24] Further details are given in the document *"Conditional projects methodology 2009/10 to 2013/14"*, EnergyAustralia, April 2008.

Annual Planning Report and Transmission Plans

EnergyAustralia also prepares three regional transmission strategy documents covering the Sydney inner metropolitan area, the central coast and the lower Hunter regions, and an annual high-level planning report, covering its transmission networks as a whole. [25] In addition, TransGrid prepares an annual planning report for NSW. We briefly reviewed these documents to see if EnergyAustralia's development plans were integrated with TransGrid's plans for its NSW network and were satisfied that was the case. [26]

Security of Supply Investment Drivers in the CBD

The plans for the transmission network supplying the Sydney inner-metropolitan area and CBD were based on reliability planning criteria jointly developed by EnergyAustralia and TransGrid. [27] These criteria apply to the combined transmission network supplying the CBD and reflect the need for planning criteria that encompass the transmission assets of both entities.

The joint planning document provides background to the decision to place the more onerous criterion (modified (n-2) rather than (n-1)) on the transmission network overall in recognition of the importance and commercial sensitivity of the Sydney area load. The document underpins decision-making in relation to the options for the CBD that EnergyAustralia outlines in its transmission and area plans.

To provide the agreed level of reliability of supply in the CBD, EnergyAustralia will undertake the following staged development:

(a) provide additional capacity to maintain an (n-2) security level from 2014 onwards,
(b) retire or replace aging infrastructure including zone substations and
(c) provide additional capacity to meet projected load growth and maintain a secure supply whilst the retirement of old infrastructure is being carried out.

With regard to the first point, EnergyAustralia does not consider it possible to provide additional transformers at existing zone substations because of space limitations. Thus, there is a need to reduce the firm capacity of the existing substations to achieve the required security level and to install additional capacity at other sites e.g. at new zone substations at City North and Belmore Park. The level of capacity reductions is dependent on the extent to which switched 11 kV interconnections can be called upon during contingency events.

A further factor to be considered is the impact of changing from an (n-1) criterion to an (n-2) criterion for the distribution network by the end of FY 2014. [28] This is illustrated in the following two tables. Table 5.2 shows the firm zone substation capacities in the CBD at present and in 2010, following completion of the City North zone substation with its full complement of transformers.

Table 5.2: Sydney CBD Zone Substation Firm Capacities in 2010

Substation	Voltage	Transformers	Secure Capacity (Current MVA)	Secure Capacity (2010 MVA)
New City North	132/11 kV	5 x 50 MVA	-	189 (n-2)

[25] *"Transmission annual planning report"*, EnergyAustralia, May 2008.

[26] This is of importance in cases where EnergyAustralia is dependent on TransGrid to develop significant assets, e.g. the next bulk supply point for the Sydney metropolitan area at Chullora, which is estimated to cost TransGrid around $500 m. See *"TransGrid revenue proposal: 1 July 2009 – 30 June 2104"*, TransGrid, 31 May 2008.

[27] *"Joint TransGrid / EnergyAustralia reliability planning criteria for the inner-metropolitan transmission system of Sydney"*, May 2006.

[28] An (n-1) security standard was applied to zone substations in the CBD up to 2006. An (n-2) level is now to be applied.

Existing City North	33/11 kV	4 x 15 MVA	46 (n-1)	-
City East	33/11 kV	6 x 15 MVA	62 (n-2)	62 (n-2)
Dalley St	132/11 kV	4 x 50 MVA	177 (n-1)	177 (n-1)
City South	132/11 kV	4 x 50 MVA	190 (n-1)	190 (n-1)
City Central	132/11 kV	4 x 50 MVA	189 (n-1)	189 (n-1)
Total			**664**	**807**

Source: *"Application notice: establishment of a new 132/11 kV CBD zone substation"*, July 2008.

Table 5.3 shows the reduction in firm capacity that will occur, once the (n-2) criterion becomes operative on the distribution network at the end of FY 2014. As can be seen, the firm capacity of the installations will be reduced from 807 MVA to 622 MVA. In comparison, the maximum demand in the CBD is forecast to be about 690 MVA in the summer of FY 2014, indicating a significant deficit in secure capacity in relation to the anticipated demand. [29]

This is a key driver of the investment that EnergyAustralia proposes in the next period.

Table 5.3: Sydney CBD Zone Substation Firm Capacities Assuming (n-2)

Substation	Voltage	Transformers	Secure Capacity (n-2 MVA)
New City North	132/11 kV	5 x 50 MVA	189
City East	33/11 kV	6 x 15 MVA	62
Dalley St	132/11 kV	4 x 50 MVA	118
City South	132/11 kV	4 x 50 MVA	127
City Central	132/11 kV	4 x 50 MVA	126
Total			**622**

Source: Table 2.2: city zone substation capacities in 2014, *ibid*.

Another factor to be taken into account when considering the proposed investment is that the long lead times involved in this work require advance procurement action for land and feeder routes and commencement of work well in advance of the required commissioning dates. [30]

Review of Projects in the CBD

Although generally satisfied that EnergyAustralia's area plans demonstrate adequately a consistent and appropriate strategy to meet its network development needs, we nevertheless examined various projects to further test the scope of investment proposed. Because of the large number of projects forecast, we limited our review of to a sample of the main projects, examining them from the standpoint of strategy, general timing, reasonableness of approach and consistency with the higher-level plans.

New City North 132/11 kV Zone Substation: The new City North zone substation is planned for commissioning in 2010. Along with City East, the present substation is the last 33/11 kV

29 Whilst under normal operating conditions it is natural for the load to be balanced between the zone substations, EnergyAustralia's general planning approach to achieve an (n-2) level of security at zone substations in the CBD under contingency conditions is to provide transformer capacity, not to rely on "emergency" load transfers at 11 kV. This approach is reflected in its area plans and various reports prepared in support of zone substation augmentation projects. The reason for it is related to cost and to operational (protection and switching) complications that would arise if load transfers at 11 kV were to be relied upon during contingencies, particularly given the "triplex" feeder system used in the CBD. Hence, the summation of capacities in Table 5.3.

30 For example, the new city zone substation has a five- to seven-year design and construction period and up to two further years for 11 kV load transfers to be effected.

zone substation within the CBD (the replacement of City East is tentatively scheduled for 2017). The May 2007 final report on the development of City North considers two components: augmentation and replacement. The assets in the existing substation are required to be replaced to enable EnergyAustralia to maintain reliability. [31] The initial stage of development, in the current period, is for three 50 MVA transformers, with a design maximum of five transformers. This enables the existing substation to be decommissioned.

The final report is inconclusive with respect to the strategy for achieving compliance with the new security level in the CBD – specifically, the extent of transformer capacity reduction and provision of 11 kV interconnections. Nevertheless, addressing demand growth and meeting compliance will require additional capacity to be provided in the CBD. [32]

Work being conducted in this next period includes the installation of the fourth and fifth transformers in order to comply with the (n-2) security level and to ensure adequate growth capacity. This is the only feasible option in the available timeframe.

In addition to the construction of the new City North zone substation, three 132 kV feeders (to be increased to five by 2012) are required to commission the substation, replace the existing 33 kV feeders and augment capacity. Two options were considered for supplying the City North substation; either via a cable tunnel linking TransGrid's Haymarket BSP and City North, or by providing the 132 kV supply in ducts. When initially studied, the cable tunnel was considered the least-cost option but the final report concluded that the two options were of similar capital cost. The City West cable tunnel has been chosen as the preferred option as it will provide strategic advantages for EnergyAustralia for future network augmentation.

The project cost is estimated to be $47 m over FY 2010-14 plus $74 m for the 11 kV duct line referred to in footnote 32 with $142 m of expenditure in current period.

Having considered the consultation paper, application notice and final report, we are of the view that the City North development with five transformers is necessary for the CBD supply. [33]

New 132/11 kV CBD Zone Substation (Belmore Park) and Other Works: EnergyAustralia issued an application notice in July 2008 for regulatory purposes to identify potential options to comply with the (n-2) security level in the CBD and to provide additional capacity for load growth. The proposal covers a number of issues currently facing EnergyAustralia, with a solution intended to deliver the most cost-effective outcome. Issues discussed include establishing (n-2) capacity in the five CBD zone substations, augmentation of installed capacity, including the need for a new zone substation and enabling the replacement of old 33 kV and 132 kV cables and other substation equipment. This is one of the more substantial developments proposed in EnergyAustralia's capex programme, with expenditure extending from FY 2009 to FY 2020 at a total estimated cost of around $978 m over that period.

Within the application notice, EnergyAustralia discussed its preferred strategy for achieving compliance of the existing CBD zone substations with (n-2) security level. As noted earlier for the Sydney CBD, it indicated that it was not possible to provide additional transformers at

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[31] The timing of the replacement is determined from condition monitoring.

[32] We noted a $74 m project to install 11 kV duct lines to Dalley St and City Central zone substations from the New City North for the transfer of capacity. The project was marked in EnergyAustralia's RIN template of major works as a requirement to meet the (n-2) security level. The explanation appeared to be inconsistent with the stated planning approach and so clarification was sought from EnergyAustralia. We understand from its response that the duct lines are required for the re-balancing of load between the substations under normal operating conditions (a normal action when a new substation is introduced) and not for load transfer during contingencies. We therefore accepted that the proposed investment was consistent with the general planning approach.

[33] These and some of the other references in this section of the report were obtained from publicly disclosed information on EnergyAustralia's web site.

existing zone substations due to space limitations, necessitating the need to reduce the capacity of the existing substations and build new ones. EnergyAustralia considers there to be two possible methods to achieve the new (n-2) security level, namely: (a) reducing the ratings of each substation by the capacity of one transformer (results in a capacity reduction of 33% at each of the three existing 132/11 kV substations within the CBD and does not utilise 11 kV interconnection capacity), or (b) restricting the zone substation capacity reductions that would otherwise be required by option (a) by the provision of remotely-switched 11 kV interconnections (EnergyAustralia considers that at a maximum this may reduce the capacity reduction required to 16% of each of the three existing 132/11 kV substations). De-rating of the existing (n-1) substations by 33% is the preferred option for achieving the (n-2) security level in the CBD. This option is less expensive than achieving (n-2) by full interconnection and is equivalent to the ideal interconnection scenario. EnergyAustralia's current preference is therefore to adopt the first option above and de-rate the existing (n-1) zone substations by 33%. Our view is that this is the better solution technically and economically. [34]

In summary, once the load transfers necessitated by the de-rating of the existing CBD zone substations have taken place –secure capacity having been reduced – there will be a need to offset this reduction with the installation of additional capacity in the CBD. The reduction in secure capacity can only be addressed by a new zone substation. This is to be achieved by several major developments including the planned introduction of a new Belmore Park zone substation in the CBD at a cost of around \$124 m plus the associated duct lines at a cost of around \$113 m – see footnote 32.

Eastern CBD Tunnel: The Eastern CBD tunnel project facilitates replacement of cross-harbour oil-filled cables from Lane Cove and will eventually link four CBD zone substations at 132 kV. Its estimated cost is \$154 m over the next period. As with the City West tunnel, such a link is expensive. However, an alternative route involving ducts through the city is considered impractical. Future benefits will accrue for connecting to other CBD substations and for the cross-harbour cables and our view is that the tunnel will be a beneficial addition and in that context its construction can be considered prudent.

Review of Projects in Sydney Metropolitan Area

Replacement of Cables 908 / 909: Primary supply to the Bunnerong sub-transmission substation is provided by feeders 908/909, 91L and 91M/3 (the replacement of which is discussed later in this report). All these feeders have poor availability, affecting the security of supply to this major substation.

Feeders 908 and 909 are the only remaining 132 kV gas-filled cables on EnergyAustralia's network. They are obsolete, have unacceptable outage rates and lack adequate spares. We reviewed the final report of 2008 on their replacement and noted that it outlined three technically feasible options for their replacement but the need for their early replacement is such that two of the options are rendered impractical through lack of time to construct and commission the Chullora 330/132 kV bulk supply point. That leaves one remaining option, which nevertheless does deliver significant benefits to south-east Sydney, the area supplied from Bunnerong.

Despite there being only one practical option to evaluate, EnergyAustralia carried out a comparative analysis with one of the disqualified options, including sensitivity analyses,

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[34] There are a number of alternative methods of forming interconnections in the CBD but their cost is anticipated to be more than de-rating by 33%. There would also be a number of technical issues to be resolved before 11 kV interconnections could be relied upon, including the congestion of cables and the matters noted in footnote 32. De-rating of the zone substations by 33% avoids them and provides a higher level of reliability, as there would be no outage on the second failure.

showing the preferred solution – 2 x 200 MVA cables across Botany Bay – as the least-cost option overall.

We are satisfied that the option chosen represents the best solution and note that it strengthens the link between TransGrid's Sydney South and Beaconsfield bulk supply points through the Kurnell sub-transmission substation. [35]

The estimated project cost is $113 m in the next period, plus $41 m in current period.

New 132/11 kV Bankstown Zone Substation: The purpose of this project is to develop additional capacity to meet forecast demand and allow old equipment to be replaced or refurbished in the Bankstown area. Three feasible augmentation options were developed and described in EnergyAustralia's final report, issued in July 2008.

We reviewed the consultation paper of January 2008 and the final report for this augmentation and are satisfied with the option selection – unchanged during the consultation process – and analysis of the preferred solution. Sensitivity analysis was conducted for differing discount rates, material costs and changes in load growth rates. The estimated project cost for this project is $35m over the next period.

The installation of a new 132/11 kV zone substation at Bankstown is part of a wider area strategy to address supply constraints in the Bankstown area, which contains eight zone substations. Four of these are 33/11 kV zone substations, supplied from the Bankstown sub-transmission substation, and part of the wider strategy includes the 33 kV switchgear replacement project that we describe below.

Bankstown and Canterbury Sub-Transmission Substation Switchgear Replacement: This is a replacement project in relation to existing outdoor 33 kV switchgear and, as such, no regulatory reports have been prepared. We reviewed the Canterbury-Bankstown area plan strategy, which highlighted that the 33 kV circuit breakers at both substations are of the bulk oil type and are at the end of their service lives. Replacement requirements are to be addressed in conjunction with work to address the non-compliant 33 kV bus bar height. Our experience with other utilities with older outdoor 22 kV and 33 kV bus bars is that replacement is a health and safety requirement as well and that modern maintenance practices provide inadequate clearances and often infringe safe working distance criteria. The preferred solution is to install a modern indoor switchboard. We support this replacement programme at Canterbury and Bankstown. The estimated project cost is $45 m over the next period.

Review of Projects in Lower Hunter and Cessnock Regions

Development of 132/33 kV Substation on Kooragang Island: The purpose of this development is to address projected limitations in the network in the Newcastle port area. We reviewed both EnergyAustralia's consultation paper and the October 2007 final report. We noted that one submission was received in response to the consultation paper but the cost of the suggested variation exceeded EnergyAustralia's preferred solution and was not adopted.

The existing area is supplied from TransGrid's Newcastle and Waratah West bulk supply points. Apart from a direct 132 kV supply to a steel mill, EnergyAustralia's Waratah sub-transmission substation provides supply to the region in consideration, including Mayfield and Shortland zone substations, and the Kooragang West switching station. This switching station provides supply to the island's 33 kV network.

[35] An associated project is the replacement of the Kurnell sub-transmission substation 132 kV bus bar, which EnergyAustralia has committed to because of the increased number of 132 kV connections required in the Kurnell Peninsula area. These 132 kV connections are required for customer connections and local asset replacement strategies.

The focus of the system limitations is on the 33 kV network from Waratah, which supplies a mixture of domestic and industrial load. The network has no further capacity, the substation has site limitations preventing expansion, the domestic supply is beyond firm capacity and equipment has reached the end of its economic life. Loading is such that replacement on the existing site is not possible as alternative supply would not be adequate should like-for-like replacement be undertaken.

New spot loads on the island will soon exceed the capacity of the existing 33 kV network and the capacity of the Kooragang West substation. Several proposals exist for new coal loaders and extensions of existing coal loaders and this region is considered one of the last remaining areas in NSW for port development. The new 132/33 kV substation would be supplied initially by two new feeders from the proposed Mayfield West zone substation.

Domestic load currently supplied from Waratah sub-transmission substation would be supplied from a new Jesmond 132/11 kV zone substation, replacing two existing 33/11 kV zone substations and removing the 33 kV load from the Waratah sub-transmission substation, enabling the retirement of much of the substation. Classified as part augmentation – the Kooragang Island sub-transmission substation development, and part replacement – the new Jesmond 132/11 kV zone substation and a refurbished Waratah zone substation.

The estimated project cost is for $84 m over the next period with $38 m in the current period. Our view is that this project is a necessary development both for the Kooragang Island industrial development, and for the residential area around Waratah.

Other Projects in Hunter Region: There were no other projects in the Hunter region that we considered exceptional.

Review of Projects on Central Coast

There were no projects on the Central Coast that we considered exceptional. [36]

11 kV Network Development

Approximately 22% of the proposed growth capex is attributable to the capital works described in EnergyAustralia’s 11 kV network development plan. The plan describes a programme of work to achieve compliance with the feeder utilisation levels in the licence conditions and the impact of growth to FY 2014. The work required is not specified by location as that would be impossible other than in the short term. Instead, EnergyAustralia has determined the scope from a comprehensive network model developed by Girna Engineering Management Services for this and related purposes. The model calculates network construction costs for a range of compliant configurations, from which the cost of an optimal network can be determined. Through processes of calibration against the existing network and the calculation of differences between alternative configurations, a theoretically efficient development plan can be determined to achieve compliant feeder utilisation levels and maintain them under growth at rates determined from the growth forecasts.

Construction costs are calculated based on historical data escalated to a common base year (FY 2007). They allow for “brown-field” development in different situations.

Costs for 11 kV feeder works incorporated under the area plans or other plans have been deducted from the estimates derived from the network development model to ensure no overlap.

[36] Other projects reviewed in our assessment (of all three regions) included those at Cessnock, Galston, Kurri, Ourimbah, Paxton and Port Botany.

We reviewed the model, which was particularly comprehensive, discussed it with its principal compiler, were satisfied that its conclusions matched the circumstances as generally known and concluded that the estimates it generated were reasonable. [37]

Customer Connection Plan

Approximately 16% of the proposed growth capex is attributable to the capital works described in EnergyAustralia's customer connection plan. [38] EnergyAustralia retained Evans & Peck to assess its customer connection capex requirements for the next period through the creation of a statistical model correlating expenditure in the period FY 2005 to FY 2008 to building consent application numbers from the NSW Department of Planning and business forecasters, BIS Shrapnel. Historical costs were corrected using escalators provided by EnergyAustralia from the CEG report. [39]

Customer connection capex in the next period is increased compared to the current period. EnergyAustralia state the increase arises from the increases in the historical expenditure rates and a forecast increase from 15,350 to 17,330 in customer connections p.a.

We considered the methodology adopted by EnergyAustralia to be suitable and the underpinning economic drivers to be based on reputable independent assessments. We thus accepted this expenditure as reasonable.

The cost of work funded by customer capital contributions is omitted from our tables and analysis and has not been examined by us for reasonableness, as we understand that mandatory policies for the calculation of contributions are in place in NSW and are being followed consistently by EnergyAustralia.

Low Voltage Capacity Plan

The low voltage capacity plan makes up 9% of the growth-related capex forecast. The plan sets out a programme of work to rectify overloading on distribution substations and low voltage mains and to maintain loading at a reasonable level in the face of load growth during the next period. It is based on a model developed by Evans & Peck for EnergyAustralia. The model extrapolates known load measurements at specific sites to the population of distribution substations and low voltage mains circuits as a whole to identify the proportion of sites likely to be in breach of the design load limits by FY 2014. [40] [41]

The modelling estimated 900 low voltage distributors and 1800 distributions substations to be above the set criteria which represents approximately 2% of the low voltage distributors and 6% of the distribution substations. Although the scope of work has been identified based on statistical estimation, particularly where load is assessed by survey, the methodology applied is logical and the loading criteria set is prudent.

Other Growth Capex

The remaining 5% of growth capex is accounted for by property purchases for network assets (1%) and other items (4%). The other items include an allocation of capitalised wages and geographic information system (GIS), demand management, intelligent networks and

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37 We also noted that around $228 m of 11 kV work was deferred in the current period: see Figure 3.1.

38 The customer connection plan excludes new meters and load control relays.

39 Competition Economists Group (CEG).

40 The load limit is 100% of distribution substation design cyclic rating if based on maximum demand indicating ammeter records and 95% if based on load survey results. Low voltage distributors are loaded to 95% of their fuse rating.

41 We raised a concern that the model did not consider the impact of differences between time constants of the maximum demand indicating ammeters and the distribution transformers, leading to the potential over-estimation of the effects of overloads. Evans and Peck, replying through EnergyAustralia, noted the low diversity of summer maximum demand as a mitigating factor. We accepted the explanation.

communications expenditure excluding SCADA. We did not examine these programmes in detail, as they are minor in terms of the total and appeared reasonable overall.

Assessment

To summarise this section, 5.3, we considered that EnergyAustralia's transmission and sub-transmission area plans, the related 11 kV network development model, customer connections plan, low voltage capacity plan and property plan were well-established documents that set out a prudent and efficient development strategy for the network and its related facilities. We considered that the analysis was comprehensive for the type of assets concerned and reflected the general principles outlined in volume 1 of this report – most importantly, the determination of need, consideration of least-cost options, consideration of optimal timing and consistency with the DNSP's policies and broader plans.

We noted that consistent with normal practice, our assessment of sub-transmission projects had entailed a review of certain major works as described in this section of the report and that our review of expenditure under the other headings comprised a review of programmes rather than projects.

EnergyAustralia provided us copies of all plans and project justifications that we requested for review and we considered that its supporting documentation and accompanying analyses were prepared to a high standard and were of a type that we would expect to receive from a well-prepared DNSP.

We noted that parts of the expenditure were supported by professional opinion from SKM and Evans & Peck as already noted in this report.

Our meetings with EnergyAustralia's experienced planning staff provided an added level of comfort to us as their knowledge of the network and its requirements was self-evident.

Our familiarity with the networks and their recent development provided a further level of comfort especially as we did not detect inconsistencies between the material provided for our review and that received for previous assessments.

Our conclusion is not affected by the fact that we reviewed the documents only at a high level consistent with our normal practice on this type of review, that other than in cases already committed to construction, or shortly to be committed, the plans remained subject to final design and approval in accordance with normal distribution engineering practice, and that the timing of installation of the various works is likely to change. We were satisfied from our review, however, that the indicative timing of the expenditure was reasonable. (Because of the integrated nature of the capital investment programme, it would not have been possible to suggest the deferral or modification of component parts of the plans without requiring that the entire programme be reviewed. We did not consider that that was appropriate for this high-level study – especially as the major transmission investments are part of a much wider joint overall programme of work prepared in conjunction with TransGrid.)

5.4 Other Considerations

Other considerations when determining the reasonableness of the scope of work included the following.

Policies and Procedures

We were satisfied that EnergyAustralia had followed reasonable policies and procedures that included the identification of need and the determination of least-cost solutions when making its investment decisions.

Adequacy of Documentation

In respect of growth-related capex, we considered that the documentation made available for our review was adequate for the purpose.

Innovativeness of Planning Practices and Designs

We considered the level of innovation being applied to EnergyAustralia's investment decisions. Innovation in this context was taken to mean mainly the adoption of sound methods and ideas or the like rather than the introduction of new technologies in terms of network equipment, although we considered both possibilities.

Engineering and Operational Methods

In terms of engineering methods and ideas, EnergyAustralia's planning team appeared to be following current international planning practice in its work in most if not all respects and importantly, for growth-related expenditure, had adopted sound network planning concepts and criteria.

EnergyAustralia already considers zone substation load diversity and load transfers through the distribution system where practical when planning its substation capacity augmentation.[42]

Non-network options and demand-side management are recognised as potential alternatives to network augmentation solutions and are provided for in EnergyAustralia's procedures in accordance with the prevailing requirements in NSW.

Construction and Installation Methods

EnergyAustralia appeared from our review to be using appropriate methods for the construction and installation of its assets.

Types of Equipment

It appeared from our review that the particular types of asset entailed in the capex programme in the next period are appropriate for the purpose.

Conclusion

We did not find any evidence that suggested that material adjustment was needed in EnergyAustralia's proposed growth-related capex on the ground of these factors. In summary, therefore, we were satisfied that the scope of work proposed was reasonable and efficient for the purpose of this review.

5.5 Efficient Costs

We then considered whether the proposed expenditure was reasonable for the scope of work envisaged – in other words, whether it reflected efficient costs. We considered this under the following headings: the basis of the cost estimates, the method used to escalate historical costs to year 2009 dollars, the extent of any real cost increases that have been included in the estimates stated in the RIN templates in year 2009 dollars and, finally, the discussion of any issues arising.

Basis of Cost Estimates

EnergyAustralia said it had built up its forecast of capex (and opex) in the next period from its demand forecast, asset data (particularly in relation to condition or, where that information

[42] As already discussed earlier in this section, for practical reasons it allows for load transfer only to a limited extent in the CBD.

was not available, to age), unit rates (which were derived mainly from recent historical expenditure), cost escalators and the application of overheads.

It said that costs associated with the identified capital works had been developed in December 2006 dollars by its own staff or consultants based on building block estimates, then escalated by relevant factors. It said that contingency allowances had not been incorporated at the project level. [43] It said and we noted that the costing methodology applied in each plan was discussed in the plan concerned and that the overall methodology was set out in a separate document. [44]

It said that individual estimates were prepared for large projects but that the general plans were costed using average project rates. We noted that the cost of major projects were based on 'green-field' estimates with adjustments in the case of 'brown-field' projects or where known site issues exist and that examples had been reviewed by SKM. [45] We noted SKM's conclusion in its review of substation costs that with the exception of civil costs, EnergyAustralia's substation costs appeared reasonable (SKM was unable to offer an opinion on the reasonableness of the high level civil cost estimates as they are largely driven by site- and manufacturer-specific factors). SKM described the estimating accuracy as appropriate for feasibility and conceptual costing.

EnergyAustralia said that the replacement programmes had been costed individually as costs vary significantly between them and that expenditure under the 11 kV distribution development programme was based on data from completed jobs. [46] It said that the distribution substation and low voltage network programmes had been estimated based on recommendations made by Evans & Peck and in turn on EnergyAustralia's internal estimates. It said that customer connection expenditure had been costed using average historical costs as determined by Evans & Peck. [47]

The cost of the duty-of-care plan is made up largely of labour and contracted services.

In considering this material and the robustness of EnergyAustralia's costs, we noted that the majority (around 80% or more) of capex is related to the procurement of materials and contract services and that they are obtained competitively.

We noted that EnergyAustralia uses its reported costs for recently completed work for the estimation of routine items and we considered that normal practice. However, as already noted in volume 1 of this report, we were not able (and thus did not attempt) to place any weight on comparisons of unit costs (rates) for the installation of lines and cables or for work on lines, cables or the equipment on them as our experience has shown repeatedly that they can vary in a range of around ten-to-one in unit cost per km of circuit length depending on the circumstances. This is before the consideration of multipliers to allow for special laying conditions such as in CBDs, rocky ground rugged terrain, remote areas or urban *vs.* rural locations and before the addition of traffic management allowances. Unit costs for other work such as distribution substation installations are prone to a lesser but significant degree of variation. Unit costs for replacement work may bear little resemblance to costs for "green-

43 Page 10 of attachment 5.4 to EnergyAustralia's proposal noted that "all estimates produced for the area plans excluded contingency, real cost escalation and inflation: these factors are applied at the program level". We have no objection to the inclusion of contingencies in cost estimates where they reasonably reflect foreseen costs – other than the inclusion of price contingencies that are allowed for in separate cost inflation provisions.

44 See: *"Estimation and cost indexation process"*, EnergyAustralia, April 2008 and *"Costing basis for building block estimates process overview"*, EnergyAustralia, April 2008, attachments to the proposal.

45 *"EnergyAustralia: a substation cost estimate review"*, SKM, April 2008: attachment 5.14 to the proposal.

46 Discussed further in *"The EnergyAustralia 11 kV network model – technical write-up"*, a confidential document provided to us for review.

47 See the attachments to the proposal.

field" or "brown-field" construction of new assets on a cost per kilometre basis because set-up costs are generally not able to be spread. [48]

Having said that, we note again that the majority (around 80% or more) of capex is related to the procurement of materials and contract services and that they are obtained competitively.

On balance, given the methodologies used by EnergyAustralia, we accepted its cost estimates as reasonable for the scope of work concerned.

Escalation to Year 2009 Dollars

EnergyAustralia has stated that it considered the impact of cost escalation when it built up its capex programme. It noted that the application of real cost escalation to the capex forecast had required the estimates to be categorised by labour, contracted services and materials so that each could be escalated at an appropriate rate, the rates mainly being those determined by CEG (although the rates were subject to a lag to account for the delayed impact of price movements). [49] We understand that the escalation rates were then applied to each expenditure stream via the cost breakdown (into labour, materials of various types, etc) to develop the capex forecasts inclusive of real cost escalation in the various inputs but exclusive of general inflation.

We asked for and received a worked example of the escalation calculations for each programme. We were also provided with various spreadsheets showing the calculation or application of the various inflation factors. Although there appeared to be discrepancies in some sheets, we were satisfied overall that the methodology applied (*viz.* use of inflators for individual inputs in combination with weights reflecting their relevance to particular expenditure categories) was reasonable in principle.

We also noted that EnergyAustralia had applied 18 months of escalation between the 2007 base year and 2008 on the basis that the average year 2007 dollars are effectively December 2006 rates and the AER requires inputs to be in real June year dollars. It is the only DNSP to have done this.

We noted the escalation factors determined for EnergyAustralia's use by CEG and other experts or by EnergyAustralia itself and summarise the real input cost escalators that EnergyAustralia said it had applied in Table 5.4. [50]

We are not able to express a view on the reasonableness of the input assumptions regarding future cost movements. Nor were we able to verify ourselves that the methodology (and the escalators stated in the table above) had been applied in the stated manner, as an audit would be required for the purpose. We have therefore relied upon EnergyAustralia's assurance that that is the case.

These factors considered, we accepted the basis of the cost estimates as reasonable for the scope of work concerned.

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48 See volume 1 section 2.4 under the heading "Unit Costs and the Efficiency of Capex Costs Generally" for a fuller discussion of this matter.

49 CEG's report is attachment 5.15 to the proposal. The escalation rate for poles (5% p.a. is understood to relate to wood poles (which are now in scarce supply) and is less than the historically reported cost escalation rate for them of about 8%.

50 The table was provided to the AER in response to the question: "EnergyAustralia's document *"Estimation and cost indexation process"* sets out the escalation factors and the corresponding inputs for different equipment/major projects which are part of the capex programme for the [next] period. For each input used in the capex programme, please provide the overall input cost weightings and please detail the weighted average escalator which has been applied to the capex programme (in real terms) for each year of the period".

Table 5.4: Real Input Cost Escalators Used for Capex (%)

YE 30 June	Weight	2009	2010	2011	2012	2013	2014
Labour	33.0	3.6	3.9	1.9	2.8	3.5	3.7
Transformers	6.7	0.9	0.2	0.6	0.0	(0.1)	0.6
Electrical equipment	8.3	0.0	0.3	0.6	(0.2)	(0.3)	0.2
Distribution substations	3.9	0.8	0.4	0.8	0.0	(0.1)	0.1
Other materials	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Cables	6.4	(0.3)	(1.5)	(0.6)	(0.8)	(0.9)	(0.6)
Poles	3.9	5.0	5.0	5.0	5.0	5.0	5.0
Cable laying and reinstatement	13.1	1.7	1.5	2.3	1.8	1.7	1.9
Civils	14.6	2.1	0.9	0.7	1.1	1.9	2.6
Fleet	4.6	3.0	1.1	1.1	1.2	1.1	2.1
Property	0.8	4.0	4.0	4.0	4.0	4.0	4.0
Other	3.6	0.0	0.0	0.0	0.0	0.0	0.0

Source: EnergyAustralia.

Real Price Increases Included in the Estimates

In essence, the effect of applying these escalation factors is that the forecast real price increases during the period FY 2009 to 2014 have been included in the estimates stated in the RIN expenditure templates in 2009 dollars to the extent shown above in the table above.

Issues Arising

Other than noting the additional six months of escalation applied by EnergyAustralia to turn its “December 2006” costs into 2007 dollars, we concluded that there was no ground on which to deem the costs applied to EnergyAustralia’s growth capex programme inefficient.

5.6 Recommended Level of Growth Capex

Having considered the factors reported in this section, we conclude that no adjustment of the growth-related capex proposed by EnergyAustralia for the purpose of this review is needed.

6 Replacement Capex

6.1 Summary of Proposed Expenditure

Table 6.1 summarises the replacement capex proposed in the next period. Expenditure under this heading constitutes 43% of the total capex proposed.

Table 6.1: Forecast Replacement Capex ($ m 2009) a/

YE 30 June	2010	2011	2012	2013	2014	Total	Pct of Total
Replacement plan	253	322	366	414	473	1,828	49%
Area plans	287	228	366	366	386	1,634	44%
Property plan	64	62	6	6	5	143	4%
Other b/	26	27	31	29	8	121	3%
	630	**638**	**770**	**815**	**872**	3,725	100%

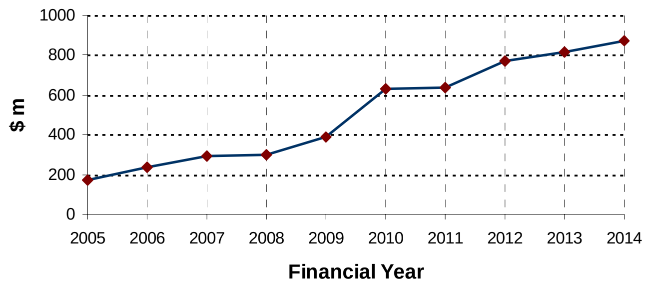
Source: EnergyAustralia with adjustments by Wilson Cook & Co to reconcile with EA's RIN template of 19 July 2008.
a/ There is a discrepency of $4 m with the RIN template.
b/ Allocation of other wages, GIS, communications, demand management development and deferral and intelligent networks expenditure.

The total expenditure proposed is $3,725 m compared with an estimated $1,383 m in the current period, an increase of 170%.

The table shows that 49% of the proposed expenditure is within the replacement plan, 44% is from the area plans, with the remaining 7% allocated from the property plan (4%) and other capex (3%).

A rising trend is evident, as illustrated in Figure 6.1. EnergyAustralia states that the increase in the rate of expenditure after FY 2008 reflects the deferral of capex from the current period to the next, the 'smoothing' applied to match capex to the resources available and the additional replacement needs now identified.

Figure 6.1: Trend in Replacement Capex ($ m 2009)



The projections reflect the commencement of a fifteen-to-twenty-year programme to replace key assets such as 33 kV gas-pressurised and 132 kV oil-filled cables and aged oil-filled switchgear. The renewal of these key assets is required to maintain supply reliability in future years and reduce risk.

The forecasts have been developed in parallel with the area plans and programmes for specific asset categories, generally based on condition and risk assessment.

6.2 Review by Category

Area Plans

Capex requirements for growth and replacement at the transmission and sub-transmission level are coordinated through EnergyAustralia's area plans. Replacement capex within the area plans accounts for $1,634 m or 44% of the replacement capex in the next period.

Capital works in the area plans are organised by project and their costs are included in the replacement figures in the RIN templates, allocated by expenditure driver. The key drivers of the replacement work are the need for replacement or conversion of 11 kV switchboards incorporating oil-filled switchgear to vacuum breaker technology (particularly where compound-filled bus chambers are used as well) and replacement of oil- and gas- filled transmission and sub-transmission cables due to their poor circuit availability.

EnergyAustralia, like other distribution companies, seeks to manage the risks arising from ageing oil-insulated high voltage circuit breakers and is able to describe first-hand experiences of destructive failures in this class of equipment, some resulting in fire. The general lack of arc suppression and controlled explosion venting in this type of equipment poses health and safety risks and its replacement over time is considered prudent. EnergyAustralia intends to replace compound-filled switchboards in poor condition but such switchboards in acceptable condition (and most air-insulated switchboards) are to be converted to use vacuum circuit breakers (although the conversion of compound-filled switchboards is seen by EnergyAustralia as an interim measure). [51]

In older and often rural zone substations, 11 kV switchgear has been installed outdoors in separate housings and condition evaluation has shown these assets to be in a deteriorated state. Replacement is programmed, based on risk and condition.

EnergyAustralia proposes several sub-transmission cable replacements. Fault rates, leakage rates, condition inspection data, environmental risk assessments and circuit availability are used to assess maintenance costs and have highlighted the need for replacement of identified gas, oil and Hochstadter single lead cables. [52]

In general, we considered that EnergyAustralia has demonstrated a suitable condition and risk-based approach to identifying these replacement needs. Particular projects in the area plans have been reviewed and are discussed under the following headings. [53]

Kogarah 132/11 kV Zone Substation

This project arises from a capacity constraint in the St George area and the condition of the Carlton zone substation. The area is characterised by an aged 33 kV network overlaid by a more modern 132 kV network. Carlton reached its firm capacity limits in FY 2008. Three other zone substations in the area are loaded above their firm capacity. Carlton comprises 33 kV and 11 kV switchgear dating from the 1950s, scheduled for replacement within five years, as are two of the three transformers at the substation. The 11 kV switchboard is a compound-filled type. The project will introduce a new 132/11 kV zone substation, enabling Carlton to be retired, load transfers and future retirements at other 33/11 kV zone substations in the area to be made, additional capacity to be brought on line and other sub-transmission constraints to be relieved. The project is the result of consideration of a number of options and is considered prudent and efficient. The estimated cost of the project is $77 m.

Lake Munmorah 132/11 kV Zone Substation

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[51] EnergyAustralia's compound-filled switchboards are generally forty to sixty years old.

[52] The poor availability of these important circuits presents an obstacle to meeting the licence conditions.

[53] The projects were selected from EnergyAustralia's list of major projects and programmes in its RIN template.

This project will introduce a new 132/11 kV zone substation, replacing the existing 33/11 kV substation on the same site due to supply constraint issues and the condition of the existing substation. The substation is presently operating above its firm capacity and new 11 kV feeders are required to reduce their utilisation levels. A current 11 kV augmentation project allows deferral of substation refurbishment until FY 2012.

Based on condition and risk assessment, the outdoor 33 kV circuit breakers and outdoor 11 kV switchgear have been identified for replacement within five years, as have one of the two 12.5 MVA transformers. Under a substation refurbishment option, the 33 kV bus bars could not be retained as they no longer meet design standard heights and the substation lacks oil containment facilities. Operational constraints on the 33 kV network, uncertainty over the viability of continued 33 kV supply from Munmorah Power Station, phasing issues and load growth in the area have led to a 132 kV re-development strategy that allows continued operation at 33 kV for Noraville and Vales Point zone substations. The project plans appear sound with the replacement requirements being integrated with wider network development issues to achieve efficient costs. The estimated cost of the project is $53 m.

New Rose Bay 132/11 kV Zone Substation

Rose Bay zone substation consists of three of 33 kV feeder transformers from Surry Hills sub-transmission substation and one 33 kV feeder transformer from Waverly zone substation. Rose Bay is operating above its firm capacity limited by the 33 kV feeder ratings and the 11 kV switchgear rating. The 11 kV switchboard is a compound filled-type scheduled for replacement, as are the 33 kV gas feeder cables 394 (by 2012) and 381 and 382 (by 2017). In addition, Surry Hills reaches its firm capacity by FY 2011.

Of four strategies considered, replacement of Rose Bay at 132 kV on land adjoining the existing substation addresses the replacement requirements conjointly with the wider network development issues in an efficient manner. The estimated cost of the project is $108 m.

132 kV Feeders 91L and 91M

Together with cables 908 and 909, cables 91L and 91M/3 provide primary supply to Bunnerong. All feeders have poor availability that affects security of supply. Cables 91L and 91M/1 provide support during outages on 330 kV cables 41 and 42. The current reliabilities of cables 91L, 91M/1 and 91M/3 are 78%, 57% and 63% respectively due to on-going leak repairs on these oil-filled cables. The quantity of lost oil is also an issue. Replacement of these cables is required for prudent management of security and environmental risk.

After consideration of four options, EnergyAustralia has elected to replace cables 91L and 91M/1 with one new feeder from Canterbury to Beaconsfield West and one new feeder from Peakhurst to Beaconsfield West via Hurstville. Cable 91M/3 will be replaced between Bunnerong and Mill Pond Road, Botany. This re-configuration of the 132 kV network realises synergies from proposed works in the St George area and represents a more efficient outcome taken in this wider context. The estimated cost of the project is $157 m.

132 kV Feeder 900

This oil-filled cable between Mason Park and Rozelle sub-transmission substations is identified as being in poor condition with a current annual reliability of 91%, diminishing its ability to act as secure back-up. Additionally, this cable circuit has submarine sections with the potential for damaging oil leaks and has an inadequate fault rating requiring the 132 kV network to be configured in a less-than-optimal manner. These factors have brought forward the replacement of the cable from the time at which it would have been decided on condition alone.

Replacement of cable 900 is proposed via a new route taking in Five Dock and Leichhardt zone substations, such that these stations may be upgraded to 132/11 kV addressing 33 kV supply issues and represents a more efficient outcome taken in this wider context. The estimated cost of the project is $60 m.

Replacement Plan

EnergyAustralia's replacement plan covers distribution assets below the zone substation 11 kV bus bar, together with assets above that line, not included in the area plans but identified for replacement as part of a general replacement programme. Table 6.2 lists the main components of the plan.

Table 6.2: Main Components of the Replacement Plan ($ m 2009) /a

Activity	Total in '10-14	Pct of total
Distribution substations	344	19%
Pole replacements programme	275	15%
LV underground mains	219	12%
Switchgear (excl. distribution substations)	200	11%
Consac cables	111	6%
HV overhead lines (excl. 5 kV network)	165	9%
Zone transfrormers	86	5%
LV services	74	4%
Ducts	56	3%
Meters	35	2%
LV overhead mains	28	2%
HV underground mains (distribution)	30	2%
SCADA	21	1%
Other programmes	184	10%
	1,828	100%

Source: EnergyAustralia.
a/ Estimate based on the percentage allocation from the replacement plan categories to the smoothed forecast.

Significant components include the replacement of distribution substations or certain types of switchgear within distribution substations, types of switchgear at zone and sub-transmission substations, poles and low voltage mains.

Distribution Substation Replacement Programme

The distribution substation replacement programme comprises 41 sub-programmes targeting specific equipment types or installation types identified by condition or performance or maintenance cost to warrant replacement. The scope of work appears prudent and the management of the work through equipment and type specific programmes is efficient.

In some cases, EnergyAustralia make provision in the sub-programmes for reactive replacements, e.g. where equipment fails in service or requires immediate replacement upon inspection. However, we considered that the reactive component of the programmes did not diminish sufficiently over the period and therefore did not recognise fully the volume and targeting impacts of the preventive replacement programmes being undertaken (and are at higher unit rates in some instances). Upon enquiry, EnergyAustralia said that the smoothing of the replacement expenditure, effectively deferring preventive replacements to later in the period, together with other actions would address that issue. We did not accept the explanation but the cost difference is immaterial in the wider context and so no expenditure adjustment is proposed.

Pole Replacement Programme

EnergyAustralia has approximately 500,000 poles, 90% of which are wood. Pole replacement is based on inspected condition against criteria set by EnergyAustralia to mitigate the risk of pole failure. The pole age profile shows a weighted average age of 37 years but with in-service poles extending to ages of 90 years.

The pole replacement forecast is based on the observed number of replacements being undertaken currently to meet the condition criteria together with a trend analysis using condition data and pole age. The FY 2008 rate of replacement, if continued, implies an expected pole life of 161 years. Obviously, that is impossible, suggesting that an increased rate of replacement is required. On the same basis, the level of replacement indicated at FY 2014 would indicate an average pole life of 83 years, which is still too high, so replacement rates can be expected to increase further beyond FY 2014. Upon enquiry, EnergyAustralia advised us that there had been a change in its condition threshold in around 2007, which had increased the required pole replacement rate.

The scope of work for pole replacements proposed by EnergyAustralia appears reasonable for the time being.

Low Voltage Underground Mains

The LV underground mains replacement reactive programme covers low voltage mains cables, service pillars and pillar components, link boxes and link components. Specific issues related to problems with concentric aluminium cable (Consac) are dealt with under a separate heading below. The programme responds to as-found condition and in-service failures, as is typical for low voltage distribution circuits in normal circumstances.

The proposed scope of work aims to replace approximately 21km p.a. If continued at this rate the 3,800 km of mains (excluding Consac and HDPE mains) would be replaced over 177 years. Taken with the significant and rising failure rate for underground low voltage mains in general, evident in the network performance figures discussed in section 2.2 of this report, the scope of work does not appear overstated.

Consac Cables

Concentric aluminium cable employs a protective aluminium sheath that is also used as the neutral conductor. Corrosion of this sheath results in a dangerous latent defect. EnergyAustralia propose a replacement programme to remove these assets, as do the other DNSPs. The expenditure is considered prudent.

Other Zone and Sub-Transmission Substation Switchgear

Other programmes target specific types of outdoor circuit breakers with the majority of the expenditure being on 33 kV bulk oil units. The programme is driven by condition assessments and appears prudent and efficient.

HV Overhead Lines

Transmission line refurbishment under this heading includes the refurbishment of corroded steel towers, replacement of sections of un-greased all-aluminium conductor due to corrosion and replacement of degraded fog-style suspension insulators. Distribution work includes the planned replacement of sections of corroded steel conductor and reactive programmes for overhead line components based on historical requirements. A provision of $14.9 m is included for natural disasters, storms and bushfire recovery, based on the spending average in years FY 2005-07. [54]

The programme scope of work appears considered and appropriate, particularly in view of the relatively high HV overhead fault rate identified in section 2.2.

Zone Transformers

Zone transformer replacements are managed through well-developed condition assessment methods largely based on oil analysis and economic analysis of a refurbishment versus replacement decision. The provisioning for three transformer replacements per year is based on historic records. Replacements due to in-service failures are managed through provisioning of spares to ensure availability when required at a high degree of confidence with an expectation, based on historic records, of four failures per year. EnergyAustralia provide for one transformer per year for refurbishment. The ratio of condition-based replacement to in-service failure suggests EnergyAustralia run close to a run to failure strategy while managing risk thereby yielding efficiency of costs in this area.

Low Voltage Services

EnergyAustralia has a programme to manage the condition of its low voltage services including the planned replacement of deteriorated services and the reactive replacement of underground service termination boxes and service cables. The preventive replacement of overhead services represents approximately 92% of the expenditure on this class of asset. [55]

Currently, EnergyAustralia experiences approximately 4,000 “service wire down” incidents and 2,200 “service wire arcing” incidents p.a. in addition to another 2,500 corrective maintenance jobs p.a. This high level of failure suggests that insufficient preventive replacement has been undertaken in the past. In the next period, EnergyAustralia proposes to increase preventive replacements at a sufficient rate to arrest the increasing average age of LV overhead services. This appears a prudent strategy to bring down the current level of failure and manage the related risk.

Ducts

Based on preliminary survey evidence, EnergyAustralia plans a modest programme of underground 11 kV cable duct replacement in the Sydney CBD over the next period. It represents approximately 2 km p.a. of the 4,140 km of duct in place.

Meters

The meter replacement programme proposed by EnergyAustralia foresees a continuation of replacement of conventional meters with time-of-use meters for high-use customers and replacements of obsolete meter types. The replacement rate proposed would turn over approximately 5% of the meter population over the 5-year regulatory period, which is a low rate in relation to the 25-year life normally assumed. As with other DNSPs, EnergyAustralia awaits a decision on the new metering requirements currently under consideration by the Government.

Low Voltage Overhead Mains

The replacement of low voltage overhead mains is undertaken on a reactive basis, driven by in-service failures and condition inspections. The forecast scope of work is based on the current rate of defects continuing. Upon enquiry, the observed step in forecast annual

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[54] See EnergyAustralia’s *Replacement Plan 2009-14*, rev 1, distribution mains, section 4.4.7.

[55] EnergyAustralia’s programme responds to an electrical safety bulletin of 1996, which highlighted problems associated with deteriorated LV overhead services.

numbers in the next period relates to the present inability to clear backlogs of identified defects.

HV Underground Mains (Distribution)

This reactive programme replaces cable sections as they fail. EnergyAustralia has no planned replacement programmes in this area, in keeping with the relatively low fault rate for its HV underground mains discussed in section 2.2 and in keeping with the age profile of the HV distribution mains cables. The forecast reactive expenditure is based on the current rate of defects continuing.

Other Programmes

Other programmes comprise some 42 categories as described in the replacement plan including instrument transformers, control and protection, buildings, batteries, earthing systems, and spares. The materiality of each programme is small in the context of the overall replacement requirements. Upon review, these plans appeared prudent.

Property Plan

We have no comment to make on strategic property purchases for substations other than to say that early action is desirable in a normal property market, especially in congested areas.

Other Replacement

EnergyAustralia split its expenditure under this category equally between replacement and growth and the expenditure involved has been discussed in section 5.3.

6.3 Other Considerations

Other considerations when determining the reasonableness of the scope of work included the following.

Policies and Procedures

We were satisfied that EnergyAustralia had followed reasonable policies and procedures that include the identification of need and the determination of least-cost solutions when making investment decisions.

The level of expenditure (and its implicit timing) proposed by EnergyAustralia for the next period appears reasonable in that it demonstrates a consistent and rising trend that is matched to the company's understanding of the age and condition of its network and to the ability of the company to resource the substantial scope of works.

Adequacy of Documentation

In respect of replacement-related capex, we found that the documentation made available for our review was generally of a high standard.

Trend in Fault Rates

The comparison of fault rates between DNSPs and our observations on EnergyAustralia's rate of faults due to equipment condition have already been outlined in section 2.2 of this report and were considered in our assessment. The scope of replacement work proposed is generally consistent with the reported fault rates and trends observed.

Conclusion

We did not find any evidence that suggested that material adjustment was needed in EnergyAustralia's proposed replacement-related capex on the ground of these factors. In summary, therefore, we were satisfied that the scope of work proposed was prudent and efficient for the purpose of this review.

6.4 Efficient Costs

We were satisfied that the factors discussed in section 5.5 of this report in relation to the efficiency of EnergyAustralia's costs for its nominated scope of work were equally relevant to the replacement capex reported in this section. Thus, we concluded that there was no ground on which to argue that the costs applied to EnergyAustralia's replacement capex programme were inefficient.

6.5 Recommended Level of Replacement Capex

Having considered the factors reported in this section, we conclude that no adjustment of the replacement-related capex proposed by EnergyAustralia for the purpose of this review is needed.

7 System Capex in Total

7.1 Other Categories of Capex

Reliability and Quality Improvement Capex

Table 7.1 summarises the reliability capex proposed in the next period. Expenditure under this heading constitutes 6% of the total capex proposed.

Table 7.1: Forecast Reliability Capex ($ m 2009)

YE 30 June	2010	2011	2012	2013	2014	Total	Pct of Total
Area plans	27	57	166	143	67	459	85%
Reliability plan	28	22	12	8	8	79	15%
	54	**79**	**178**	**152**	**74**	538	100%

Source: EnergyAustralia with adjustments by Wilson Cook & Co to reconcile with EA's RIN template of 19 July 2008.

The total expenditure proposed is $538 m. Expenditure under this heading is predominantly made up of the cost of bringing the network into compliance with the licence conditions.

The table shows that 85% of the proposed expenditure is attributable to work in the area plans and the remaining 15% is attributable to work on feeders. Major expenditure under the area plans includes the up-grading of Dalley Street and Central City zone substations to the required (n-2) security level. [56]

Expenditure on feeders to meet the requirements of schedules 2 and 3 of the licence requirements (which relate to average and individual feeder reliability respectively), together with a sum of around $16 m to undertake "black spot" reliability improvement for the worst-affected customers, is described in the reliability investment plan and makes up the remaining 15% of expenditure under this heading. The projects involved have been determined through availability modelling on the network and take account of the effects of the investments made under the 11 kV network development plan and the area plans. [57] EnergyAustralia says that the investment will improve the average reliability of supply to 2011 and maintain it thereafter.

In planning to meet the requirements of schedule 2 of the licence conditions for average feeder reliability, Energy Australia has aimed for a 95% level of confidence in meeting each of the eight reliability measures (SAIDI and SAIFI in each of four feeder categories), calculating that setting a 95% level of confidence in each of the eight separate targets will result in a 34% probability of being in breach of any one target in any one year – being (1-(1-0.05)^8). [58] When asked about this approach, EnergyAustralia stated that it considered the schedule 2 reliability requirement to be mandatory and that it had discussed its approach informally with the Department of Water and Energy. It stated that the parties resolved to

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56 The CBD area plans have been discussed in section 5.3. Works at a number of sites including these address growth, replacement, reliability and compliance issues together.

57 The 11 kV network development plan includes an extremely comprehensive piece of modelling and EnergyAustralia arranged for us to meet its principal author to discuss the approach used. We did not consider examining the model in detail because of the work involved.

58 SAIDI and SAIFI are not independent but correlated to a degree, so the probability of non-compliance is likely to be less than calculated by EnergyAustralia.

monitor compliance outcomes to determine the effectiveness of the proposed targets in achieving compliance.

We do not express an opinion on the appropriateness of setting a target in this way, since it appears to be a matter of interpretation of the licence conditions. However, we note the matter for consideration by the AER as potentially it gives rise to different levels of expenditure by the DNSPs in circumstances that otherwise would be the same.

We considered the reliability improvement capex reasonable when based on the method of compliance chosen by EnergyAustralia.

Compliance Capex

Table 7.2 summarises the capex proposed in the next period for environmental, safety and statutory compliance. Expenditure under this heading constitutes 5% of the total capex proposed.

Table 7.2: Forecast Compliance Capex ($ m 2009) a/

YE 30 June	2010	2011	2012	2013	2014	Total	Pct of Total
Area plans	9	25	54	53	24	165	37%
Duty of care plan	59	52	56	60	59	285	63%
	68	**77**	**110**	**113**	**83**	450	100%

Source: EnergyAustralia with adjustments by Wilson Cook & Co to reconcile with EA's RIN template of 19 July 2008.
a/ There is a discrepency of $10 m with EA's RIN template.

The total expenditure proposed is $450 m, compared with an estimated $196 m in the current period, an increase of 135%. The table shows that 63% of the proposed expenditure is attributable to the duty-of-care plan and the remaining 37% is attributable to compliance work in the area plans.

EnergyAustralia considers compliance capex under three categories: safety and security, environment and infrastructure risk. The safety and security category comprises various programmes covering public and workplace safety, fire mitigation and asbestos management or removal. Major programmes in this category include the correction of 33 kV bus bar heights and protection for brick-walled outdoor enclosure substations. Environmental programmes address EnergyAustralia's obligations in respect of waste disposal, pollution management and contaminated land with the major expenditure being in oil containment programmes. The infrastructure risk component is in response to national guidelines for the protection of critical infrastructure and includes site security, battery duplication (to comply with the National Electricity Rules) and the installation of under-frequency load-shedding relays. Major projects in this category include the installation of electronic security and the replication of the system control centre in Sydney at a secure location.

Compliance expenditure at zone and transmission substations is coordinated through the area plans that account for approximately 37% of the expenditure in this category. Major identifiable projects under the area plans include the replacement of transformers at City South and Dalley Street zone substations with gas-insulated units to reduce the risk of fire and the correction of 33 kV bus bar heights at various locations. [59]

After consideration, we accepted the proposed expenditure under this category as reasonable.

[59] See footnote 56.

Other Capex

The category of "other capex" accounts for $151 m over the next period or 2% of the total capex proposed. According to the expenditure reconciliation tables supplied by EnergyAustralia – see Table 4.3 – this category comprises capex on metering and system IT.

Metering capex appears to relate to new franchise meters and trials of advanced metering systems and makes up approximately 61% of this expenditure category. [60]

System IT capex includes outage management system improvements, integrated asset management systems, mobile computing, information systems associated with intelligent networks, SCADA and system connectivity.

We did not review these various or the items under the "other" category in detail but considered them reasonable in total.

7.2 Other Considerations

Coordination of Work and Overlap of Expenditure Estimates

We noted evidence that capex programmes and projects under the various expenditure headings were coordinated to avoid inefficiencies.

We did not find any evidence that suggested overlapping or double counting of expenditure.

Deliverability

EnergyAustralia has recognised the need to increase its resources to deliver its proposed investment programme and has taken measures to ensure that it is able to do so. In essence, it proposes to increase the capability of its staff through the use of standardised designs, advanced design software, network automation and the deployment of mobile computing; increase the work undertaken by contractors e.g. for cable laying, civil and building work, and establish alliance agreements with private sector construction companies and consultants to undertake major projects under turn-key-style arrangements.

As already noted in volume 1 of this report, the terms of reference did not require us to opine on the ability of the DNSPs to implement their plans or on whether we considered they might experience constraints in resources. However, in commenting on the draft report, the AER asked us for our view on this matter. Whilst the answer can only be conjectured, we see no reason why the DNSPs, along with others in the country and worldwide, cannot gear up for the additional workload foreseen, providing they take concerted action for the purpose. In that context, we noted that each DNSP had put forward its plan for the purpose and we considered that each had adopted a reasonable strategy. We expect that expenditure will ramp up over the period due to the need to increase the resource base and this is reflected in some of the DNSPs' proposals.

7.3 Recommended Level of Total System Capex

In summary, having considered the factors reported in sections 4 to 7 of this volume, we conclude that the growth capex proposed by EnergyAustralia is prudent and efficient within the limits of this review and that no adjustment of the total system capex proposed by EnergyAustralia for the purpose of this review is needed. [61]

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[60] Meter replacements are included in the replacement plan but new meters are included under growth capex.

[61] A comparison of total capex with the replacement cost of the asset base would normally be made at this point in the review to check for reasonableness but was not attempted in the absence of an up-to-date replacement cost valuation of the assets and in light of the fact the licence condition compliance expenditure distorts capex in the period reviewed.

8 Non-System Capex

8.1 Summary of Proposed Expenditure

EnergyAustralia's non-system capex comprises expenditure on non-system IT, plant, equipment, motor vehicles, land, buildings and other non-system assets. Expenditure in the current and next period is shown in Table 8.1. Expenditure under this heading constitutes the remaining 7% of the total capex proposed. The analysis is of total non-system capex, *viz.* the sum of that allocated to distribution and transmission.

Table 8.1: Current and Forecast Non-System Capex ($ m FY 2009)

	Actual			Estimated		Proposed					Total in	Pct of
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	Total
IT systems	20	24	32	58	66	82	50	37	39	32	240	39%
Furniture, fittings, plant and equipment	6	5	5	7	6	6	6	6	6	6	28	5%
Motor vehicles	23	22	25	27	28	26	23	19	17	17	101	16%
Buildings	7	9	14	31	61	68	38	50	26	29	210	34%
Land	0	9	1	19	27	41	0	0	0	0	41	7%
Other non-system assets	0	2	(0)	0	0	0	0	0	0	0	0	0%
	56	**71**	**77**	**142**	**188**	**223**	**116**	**111**	**87**	**83**	620	100%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.

The total expenditure proposed in the next period is $620 m, compared with $534 m in the current period, an increase of 16%. In the next period, expenditure on IT systems and buildings is projected to be higher than the current period, whilst expenditure on motor vehicles and land is projected to be lower. Expenditure on furniture, fittings, plant and equipment is projected to be at similar levels to the current period.

Basis of Forecast

EnergyAustralia has generally used a "bottom-up" approach to forecast its non-system capex.

Application of Cost Escalation Factors

EnergyAustralia advised us that it had applied cost escalators from the CEG report to non-system capex as shown in Table 8.2. The escalators are expressed in nominal terms.

Table 8.2: Cost Escalators Applied to Non-System Capex (%)

Item	**Escalator**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
IT labour	CEG – general wages	4.4	4.9	4.3	4.3	4.5	4.4
IT software/ licences	CEG – general wages	4.4	4.9	4.3	4.3	4.5	4.4
IT hardware	No escalation	0	0	0	0	0	0
Land	BIS Shrapnel (average)	6.9	6.5	6.5	6.6	6.6	6.5
Buildings	CEG – construction	5.0	3.3	3.1	3.6	4.4	5.1
Fleet	No escalation a/	0	0	0	0	0	0
Plant and tools	CPI only (no real increase)	2.8	2.4	2.4	2.5	2.5	2.4
Furnishings	CPI only (no real increase)	2.8	2.4	2.4	2.5	2.5	2.4

Other	CPI only (no real increase)	2.8	2.4	2.4	2.5	2.5	2.4

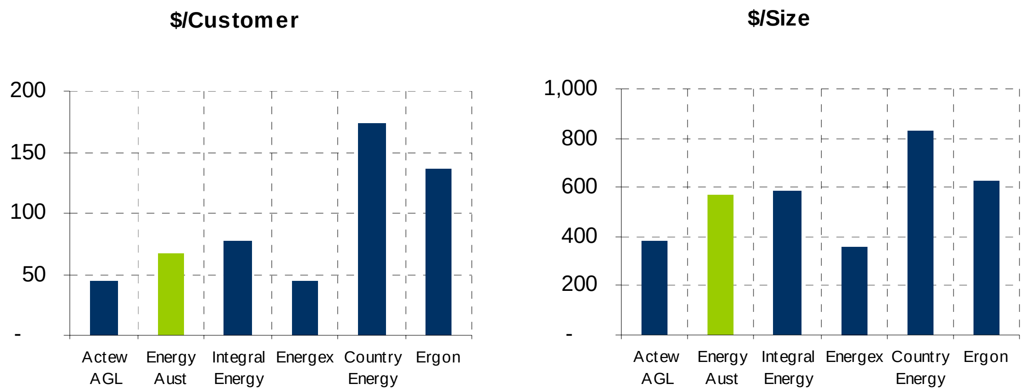
a/ EnergyAustralia advised us that CPI escalation should have been applied to motor vehicles and said that its omission was due to an oversight. We discuss this further in section 8.2 under the heading "Motor Vehicles".

All sums were converted to 2009 dollars after the application of the cost escalators.

Efficiency of Overall Expenditure

EnergyAustralia's average non-system capex for the next period has been compared on a cost-per-customer and a cost-per-size basis with the other ACT and NSW DNSPs' forecasts and the regulatory allowances for Energex and Ergon Energy in the 2005 Queensland determination.[62] The comparisons are shown in Figure 8.1.[63]

Figure 8.1: Comparison of Non-System Capex



We consider that "cost per size" is the best benchmark to use as a comparison because it takes account of the main parameters that drive non-system capex. The comparison shows that EnergyAustralia's forecast non-system forecast capital cost per size is in the middle of the range of the group analysed.

We consider that the benchmarking confirms from a "top-down" perspective that Energy Australia's overall level of non-system capex is reasonable.

The following sections of the report consider the proposed level of non-system capex from the standpoint of a "bottom-up" review of specific expenditure categories and projects.

8.2 Review by Category

IT Expenditure

EnergyAustralia is proposing to spend $240 m on IT assets in the next period compared to $200 m in the current period, an increase of 20%. It says that it invested heavily in IT systems in the current period but that the investment was less than the depreciation charge on its IT assets and therefore has not reflected the true renewal requirements of the business over the last five years.

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62 EnergyAustralia's expenditure excludes transmission-related costs.

63 Size is taken as a composite variable $C^{0.5}L^{0.3}D^{0.2}$ where C equals the number of consumers, L equals the km of line and D equals the maximum demand, representing the networks by their key characteristics. This measure of size was developed by Ofgem but we have substituted demand for energy throughout in the formula on the ground that demand is a stronger driver of expenditure in a distribution lines business than is energy. Further details of the composite size variable are given in section 3 of volume 1 of this report.

EnergyAustralia says that it has developed a comprehensive strategy for future IT needs covering both network support and business support IT as the two are now closely interrelated, with the use of glass fibre technology for data capture, equipment automation and network protection. The strategy also takes account of like-for-like replacement for applications that have ongoing use and scopes new initiatives that are planned for the 2009-14 period. Significant forecast IT work programmes include the following items.

Data Centre Consolidation: This programme will consolidate infrastructure presently housed in eight data centres and 28 depots to two tier three data centres. The data centres will house critical applications and services and provide system backup. The programme commenced in the current period and will be completed in the next.

iAMS: EnergyAustralia has commenced a project to implement an integrated asset management system (iAMS) in SAP, which will "go live" in 2008. It will enable linking of financial, technical and performance information for all network assets, as well as the consolidation of asset databases and systems. During the next period, EnergyAustralia says it will focus on delivering additional value from the iAMS platform. Some of these improvements include adding functionality to support contract labour and increasing integration with systems such as the geographic information system.

GIS: The GIS system will be upgraded and enhanced to allow to access to it and updating of it from the field.

SAP: An upgrade of the core system is required.

Network Billing and Customer Information System: The present system is not meeting the needs of network billing. A standard data model will be implemented to allow distinct and specialist network billing. A customer relationship management system will also be introduced as part of this project.

Metering Systems: Consolidation of several metering systems to provide an integrated metering data management and reporting system is proposed.

Field Computing: Expansion of field computing initiatives commenced in the current period and is to continue.

Hardware: A step-increase is proposed to upgrade hardware to current standards.

We reviewed the supporting documents provided by EnergyAustralia [64] and asked for sample of business cases for recently completed or soon to be implemented projects, recognising that full business cases are yet to be completed for projects in the next period. Our review of the document showed that projects are identified based on need and the costs, benefits and risks are stated for each programme. The cost estimates have generally been prepared at a 'budget' level based on market knowledge, particularly in the case of projects that commence later in the period. We noted that EnergyAustralia had tested its cost estimates for reasonableness against the reported costs of similar systems in other companies and found them to be comparable.

We noted that there are also some large increases in opex forecast as an outcome of the proposed investments. These are at a total level for each programme and have not been detailed to the same extent as the capex forecasts. We comment further on this in section 9 of this report.

We reviewed the business case for phase three of the iAMS project and for the outage management system. We found that the business cases contained comprehensive information

[64] "*Non-system IT executive overview*" (Attachment 5.11), "*Non-system IT detailed proposal*, and "*Non-system IT supporting document*.".

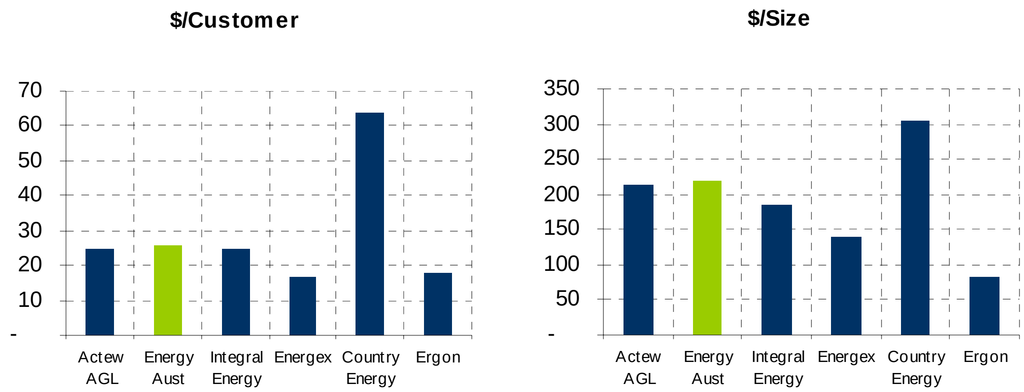
on the costs of the projects, the business drivers that were influencing the need, the business benefits that would be achieved and the risks to the project. We noted in the iAMS case that there was little quantification of the financial benefits had as it was said there was a "*lack of baseline data on which to compare*". The major financial benefit justifying the expenditure is an expected improvement in the information available to make efficient capex and opex decisions and to support expenditure forecasts, particularly in relation to regulatory determinations. Little emphasis had been given to potential efficiency gains that the system might achieve. We consider that whilst this can be difficult to measure or predict, it is something that should be considered to make sure that investment in systems does lead to efficiency in the business.

The business case risk analysis highlighted a high probability of difficulty in changing processes within the organisation to achieve the desired outcomes from the investment. This is a common issue with IT investment and needs to be addressed to ensure the benefits on which the investment is made are achieved.

Overall, the proposed investment is in IT systems that are typical of those in other network businesses and a business the size of EnergyAustralia does require integrated systems to operate efficiently. The number of major projects over the period is high but this appears to reflect some previous under-investment. We found nothing unusual or excessive in the proposed programme but noted that improvements could be made in identifying the business efficiency improvements to be expected from the investments.

As an additional test, we benchmarked IT expenditure on a cost-per-customer and cost-per-size basis, as shown in Figure 8.2. The figure shows that EnergyAustralia's proposed IT capex is a little above that of comparable distributors but not excessively so, considering there is some catch-up expenditure planned.

Figure 8.2: Comparison of IT Capex



After considering these factors, we concluded that the expenditure on IT systems was reasonable without adjustment but noted that such investments should result in improved business efficiencies and operational cost savings. We comment further on this in Section 9.

Motor Vehicles

EnergyAustralia is proposing to spend $101 m on motor vehicles in the next period compared to $125 m in the current period, a decrease of 19%. Its forecast fleet expenditure over the next period comprises mainly replacement expenditure on its existing fleet (82% of the projected expenditure) in accordance with its documented vehicle replacement policies. The forecast includes increases in the size of the fleet to support the proposed capital investment and maintenance programmes. It has assessed the required additions to the fleet over the next period by considering expected staff increases, the movement of apprentices from training into operations, changes to regulatory safety requirements respect of safety and technological changes.

We reviewed the supporting document provided, [65] which outlined the fleet management policies and the process used to determine the forecasts. We were satisfied that the policies and processes were appropriate.

Land and Buildings

EnergyAustralia is proposing to spend $251 m on land and buildings in the next period compared to $179 m in the current period, an increase of 40%. Offsetting this expenditure, the sale of surplus land and buildings is expected to realise $66 m, which will be removed from EnergyAustralia's regulatory asset base. The net expenditure for the period would therefore be $185 m. We were provided with a supporting document [66] outlining the corporate property strategy. EnergyAustralia said that its forecast is based on a recent strategic review of non-system-related property holdings. The review was driven largely by staff numbers having increased since 2004 from 3,976 to over 5,000 and staff accommodation not having kept pace with the growth with the result that much of it is now sub-standard. The review also found that there is scope to improve the strategic fit of holdings with current business operations and functions. The review took into account the prospective sale of the retail business.

EnergyAustralia currently occupies 44 sites including eight offices, thirty depots, a warehouse, three training and testing facilities and two pole yards. [67] The review of property holdings found that some regional headquarter sites do not match the current business structure, some sites are under pressure from surrounding development, some are under-utilised, some are overcrowded and some require significant maintenance.

The review identified and considered six different options to meet future needs. The costs of the options were reviewed by quantity surveyors and property experts and land valuations were sought from independent valuers. The selected option is based on three zones with six regions for operational purposes. EnergyAustralia says that the option is consistent with its planning criteria and represents the least-cost approach. Details are given in the plan.

We considered that a robust process had been followed and that the proposed expenditure was reasonable.

Furniture, Fittings, Plant and Equipment

EnergyAustralia is proposing to spend $28 m under this expenditure category in the next period compared to $29 m in the current period. We consider the proposed expenditure reasonable, based on the historical trend.

Other Non-System Capex

No expenditure is proposed in this category.

8.3 Recommended Level of Non-System Capex

Having considered the factors reported in this section, we conclude for the purpose of this review that no adjustment of the non-system capex proposed by EnergyAustralia is needed.

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65 *"Fleet capital investment forecasting process"*.

66 Confidential attachment 4.12: *"Corporate property strategy"*.

67 Excluding substations and switching stations.

9 Opex

9.1 Expenditure in Current Period

Table 9.1 shows that EnergyAustralia's distribution opex is projected to be $1,869 m over the current period, representing a total expenditure that is $269 m or 17% above the total allowed by IPART in its determination inclusive of agreed pass-through costs.

Table 9.1: Distribution Opex in Current Period *vs*. Determination ($ nominal)

	Actual			Estimated		Total
YE 30 June	2005	2006	2007	2008	2009	
Determination (IPART)	288	303	312	319	326	1,548
Pass through events	0	3	11	17	20	51
Opex in current period a/	291	357	321	425	475	1,869
Over-run / (under-run)	**3**	**51**	**(2)**	**89**	**129**	**269**
Over-run / (under-run) (%)	1%	17%	(1%)	28%	40%	17%

Source: EnergyAustralia.

Table 9.2 shows that EnergyAustralia's transmission opex is projected to be $156 m over the current period, representing a total expenditure that is $25 m or 19% above the total allowed by the ACCC in its determination.

Table 9.2: Transmission Opex in Current Period *vs*. Determination ($ nominal)

	Actual			Estimated		Total
YE 30 June	2005	2006	2007	2008	2009	
Determination (ACCC)	24	25	26	27	29	131
Pass through events	0	0	0	0	0	0
Opex in current period	23	28	28	37	41	156
Over-run / (under-run)	**(1)**	**3**	**1**	**9**	**12**	**25**
Over-run / (under-run) (%)	(5%)	14%	5%	33%	43%	19%

Source: EnergyAustralia.

The tables show that EnergyAustralia will overspend against its allowances in both distribution and transmission over the period, with the level of overspending increasing each year over the period. EnergyAustralia attributes the over-expenditure to the following factors:

- failure of past regulatory decisions to provide adequate funding to maintain and operate the network,
- an increase in input costs, particularly labour, above inflation over the current period,
- an increase in the number of apprenticeships needed to meet workforce requirements,
- increased property taxes, rents and rates from additional property and
- additional demand management, energy efficiency and pricing initiatives.

9.2 Proposed Expenditure in Next Period

Overview

EnergyAustralia's proposed opex in the next period compared with that in the current period is shown in Table 9.3. Although EnergyAustralia provided separate tables for distribution and transmission in its RIN templates, all supporting information is based on opex in total. We have therefore analysed opex in total, rather than attempting to consider it by distribution and transmission separately.

Table 9.3: Current and Forecast Opex ($ m 2009)

	Actual			Estimated		Proposed				
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Network operating	90	91	106	140	163	183	189	191	196	199
Network maintenance	165	173	190	198	210	220	226	237	248	261
Other expenditure	104	158	79	137	143	155	159	165	172	172
	358	**423**	**374**	**474**	**516**	**558**	**574**	**593**	**616**	**632**

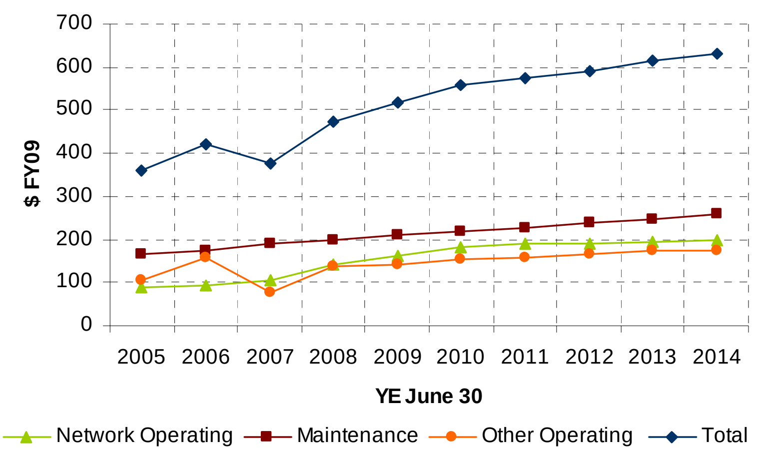
Source: EnergyAustralia.

The total opex proposed in the next period is $2,972 m compared with an estimated $2,145 m in the current period, an increase of 39%. [68] EnergyAustralia has stated that the reasons for the increased level of expenditure include:

- increased workload largely arising from the larger asset base, adding approximately 25% to direct maintenance costs,
- increased workload due to the increasing age of network assets,
- cost increases above inflation and
- step changes arising partly from the higher costs of IT following the introduction of new systems and partly from a need to meet statutory and regulatory obligations.

Figure 9.1 shows the trend of expenditure from FY 2004 to FY 2014.

Figure 9.1: Trend in Opex from FY 2004 to FY 2014 ($ m 2009)



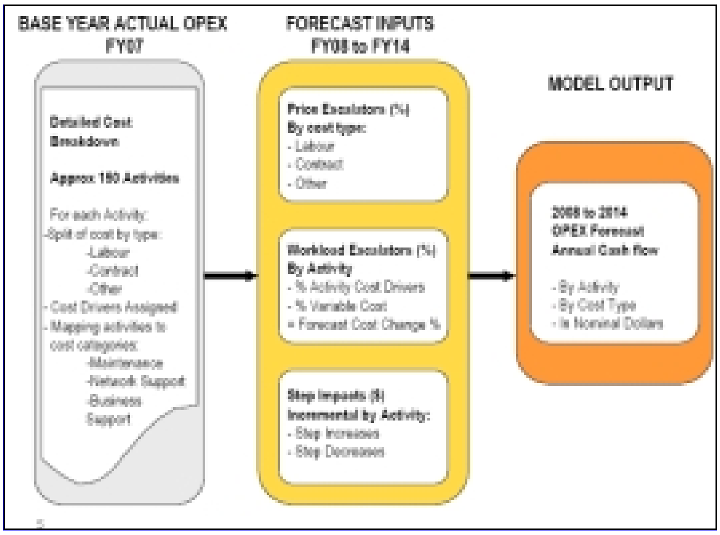
[68] For distribution, the total opex proposed in the next period is $2,786 m compared with an estimated $1,980 m in the current period, an increase of 41%. For transmission, the total opex proposed in the next period is $187 m compared with an estimated $165 m in the current period, an increase of 13%. Total opex includes self insurance but excludes debt and equity raising costs.

The graph shows a rising trend in the all the main expenditure categories. The change in the trend between 2006 and 2007 is due to abnormal costs or credits, the latter mainly arising from an abnormal superannuation fund payment in 2006 and a credit in 2007.

Expenditure Model

EnergyAustralia has developed a model to derive its opex forecasts as shown in Figure 9.2.

Figure 9.2: Opex Forecast Methodology



It stated that its "core" network opex forecasts have been derived by establishing actual costs by activity for the base year (FY 2007), removing abnormal costs from that year, applying step increases and decreases by activity, applying input cost escalation factors, applying workload cost escalators by activity including the interaction between opex and capex and converting the model's output in nominal dollars to year 2009 dollars.

Impact of External Factors

EnergyAustralia advised us that it has not incorporated any specific costs that are directly attributed to meeting new or future obligations within the operating programme, apart from the impact on opex of the increased capex programme, which in turn is partly driven by the need to comply with the licence conditions.

9.3 Issues Arising

Application of Cost Escalation Factors

Labour costs have been escalated in accordance with the escalation factors in the CEG report compiled for all three NSW DNSPs and described in section 5.5. The industry-specific electricity and gas workers index has been applied to labour in the network and contracting business units and the general wage index has been applied to labour in the corporate and shared services business units, contracted services such as meter reading and IT and tree trimming. EnergyAustralia stated that it had not applied real cost escalators to any other cost inputs for opex. The effect of real cost escalation from the normalised base year adds approximately 12% to opex in the next period.

We noted that EnergyAustralia has applied 18 months of escalation between the 2007 base year and 2008 on the basis that the average year 2007 dollars are effectively December 2006 rates and the AER requires inputs to be in real June year dollars. It is the only DNSP to have done this.

Impact of Workload Escalation

EnergyAustralia has used workload escalators (drivers) to account for the change in volume in each work activity from the base year. Workload escalation has been applied only to the variable element of costs. Examples of the escalators applied are shown in Table 9.4.

Table 9.4: Examples of Workload Escalators

Workload Escalator	Activities Affected
Customers (network connections)	Emergency despatch, billing
Call volumes	Contact centre
Real land value	Building and grounds maintenance
Meter population	Meter maintenance
PC volumes	PC help desk

EnergyAustralia said that the most significant influence on opex during the next period will be the proposed capex programme with the programme having both a negative and positive impact on opex. It says that asset replacement has a downward influence on maintenance costs where the volume of assets replaced has a marked downward impact on the weighted average age of the asset class but that where the replacement is not sufficient to arrest the rise in weighted average age of the asset class concerned, maintenance costs will continue to increase. However, we noted that the biggest changes in cost were not in maintenance but in network and business support costs.

Numerous different escalators have been used and we reviewed the opex model to see what had been applied in various categories. We considered the escalators were reasonable approximations for workload growth, except in the following two cases:

- *Real system capex:* The use of a dollar value overestimates the level of workload increase as real input cost escalators are applied to the estimates.
- *Maintenance:* As outlined below, we are not convinced that the relationship between asset age and maintenance expenditure is exponential or that a valid curve can be derived from two data points.

In addition, we had concerns over the application of one escalator, *viz.* the use of real system capex growth as a driver of network major projects and engineering and of asset and investment management: It is to be expected that an increase in capex will require more management and engineering time. However, costs directly related to projects ought to be capitalised. In addition, the value of a project is not necessarily an appropriate measure of the resource required to oversee it. To examine this point further, we asked EnergyAustralia for a forecast of staff numbers and found that the level of increase in the overall network group was relatively modest compared with the increases in capex. [69]

The impact of applying the workload escalation to the normalised base year adds approximately 9% to the average opex for the next period as compared to the base year.

We comment further on these issues in section 9.5 below.

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69 In commenting on the draft report, EnergyAustralia said it had addressed this issue in a response to us but the response received did not, in our view, justify the use of this escalator for these costs.

Impact of Capex-Opex "Trade-Off"

The impact of replacement capex (or the lack of it) on opex was discussed by Energy Australia in its proposal. As EnergyAustralia observes, it is well understood that, other things being equal, the level of maintenance expenditure needed on a network will increase as the network ages. [70]

EnergyAustralia was not alone amongst the DNSPs in reporting a possible relationship between maintenance expenditure and asset age that had been developed by SKM for various DNSPs to provide an insight into the potential trade-off between replacement capex and maintenance expenditure. The relationship suggested by SKM is based in turn on the assumption of an exponential relationship between opex and age. EnergyAustralia has completed this analysis for its main network asset classes and has produced a graphical relationship between expenditure and age, from which marginal additional maintenance costs can be read for given movements in the average age of the assets. The relationship was developed using two "known" points – the actual current level of opex (based on FY 2006 actuals) and the current age of the assets, and an estimate of the level of opex applicable to new assets (based on a percentage of replacement costs, the percentage having been determined by SKM in 2002).

Our view of the analysis is as follows.

- Quantitatively, the analysis begs the questions:
  - whether the costs of maintaining new assets are comparable with those of maintaining old ones (this affects the first point on the graph and the relationship between the points);
  - whether the first point on the graph (the cost of maintaining a new asset), established by assuming that maintenance costs are a percentage of the replacement cost of a new asset but using a percentage developed in 2002) is still relevant, given the significant change in replacement costs over the last five years;
  - whether the present maintenance costs are efficient – we note that Energy Australia was still catching up on a backlog of deferred maintenance in FY 2006 (this affects the second point on the graph); and
  - why the curve should be exponential. [71]

Although intuitively a relationship would appear to exist, evidence available to us from the New Zealand electricity supply industry suggests that direct costs may not increase *exponentially* with the average age of the network components, although they may be related to age in another way. [72]

In respect of the first question, after enquiry from us, EnergyAustralia undertook further analysis and concluded that the changes since 2002 would reduce the projected expenditure by $19.4 m or 1.6% over the next period. We were also advised that it had discovered errors in its asset age profile information, resulting in the need for a further adjustment of $4.1 m.

70 This is a consequence of deterioration of asset condition, the need for more frequent inspection and maintenance and an increase in the failure rate of assets in service.

71 Exponential growth in expenditure of any type seldom occurs in reality.

72 We tested the assumption that there is an exponential relationship between direct maintenance cost and the average age of the network components by looking at New Zealand company data. New Zealand data was used due to its availability for all companies. Data for both 2005 and 2006 were tested with comparable results. We used total installed transformer capacity to normalise different network sizes. More complex regression formulae for network size were not considered warranted, based on the observed relationships between direct costs and up-to-date ODV fixed asset valuation data, all of which were available for all companies in the data. The average network age was derived from the valuation data. From the dispersion of the points by type of network, we found that network type was a much stronger driver of cost. However, even within networks of the same general type, we found no obvious regression and, if anything, a direct linear relationship between direct costs and age seemed to have stronger trends.

In our opinion, there is doubt about the robustness of applying EnergyAustralia's analysis to derive a workload escalator for maintenance.

Proposed Step Changes from Base Year

EnergyAustralia has factored a large number of step changes into its forecast level of opex. Most of these occur between the base year and the start of the next period. Excluding adjustments for abnormal items in FY 2007, [73] the step changes in this period total $64 m. The effect of the step changes is to add approximately 15% to average opex in the next period compared to the base year. The step changes are mostly the result of business decisions made by EnergyAustralia, not decisions made in response to outside factors. Some are proposed on the ground that the base year for some activities was not "normal": others, particularly in IT, arise from incremental opex related to capital investments.

The proposed step changes are reviewed in section 9.5 but we note the following general points. First, in a competitive market, businesses do not normally add to their own costs unless they are satisfied that there is a benefit to customers in terms of the product delivered or to the business in terms of efficiency. Regulation presumably ought to incentivise natural monopolies in a similar way. Second, businesses are dynamic, with variations occurring from year to year. Such variations ought not to form the basis of a claim for a step change, as the effect of that would be to allow costs to be passed on readily in contravention of the efficiency objective implicit in the regulatory framework.

We consider that a methodology such as that used by EnergyAustralia that starts with a base year and then applies cost escalators, workload escalators and step changes (which apart from some adjustments for abnormal items in the base year are almost all additional costs) without any explicit consideration of business efficiency improvements or potential cost savings is likely to lead to a forecast of future costs that is above an efficient level.

We therefore consider that for acceptance as a step change, a cost ought to relate to a fundamental change in the business environment arising from outside factors or be offset by cost efficiencies in other areas.

No Allowance for Productivity Savings

We could not find any indication that EnergyAustralia has allowed for specific improvements in organisational efficiency or productivity in its proposal. It advised us that productivity changes had been allowed at a "sector" level in the forecast of future labour costs. However, we consider that the large investment proposed in IT systems and property should lead to improvements in business efficiency and reductions in opex.

9.4 Efficiency of Overall Expenditure ("Top-Down" Analysis)

Efficiency of Base Year

Before proceeding to a review of the proposed opex by category, we first considered the efficiency of the proposed base-year opex, using a "top-down" approach and the benchmarking methodology described in volume 1 of this report.

Adjustments were made to the FY 2007 reported figures of all companies to remove abnormal and one-off items. The adjustments made for EnergyAustralia related to the 2007 storm event, a one-off superannuation fund credit and a change in the treatment of fleet and logistics recoveries.

[73] The effects of the storm in 2007, the superannuation rebate and an accounting change relating to fleet and logistics recoveries.

The conclusion drawn from the analysis in volume 1 of this report with respect to Energy Australia was that its FY 2007 opex is at or a little above the industry norm, established by a variety of comparisons. We are not able to say that EnergyAustralia's levels of opex are sufficiently at variance from the industry norm to conclude that they are inefficient, although the analysis tends to suggest that there may be potential for efficiency improvements within the business. A more detailed assessment of the businesses, beyond the scope of this review, would be required to quantify the degree of any efficiency gains possible.

Our conclusion from the comparative analysis is that EnergyAustralia's FY 2007 opex can be considered a reasonable starting-point for its future projections.

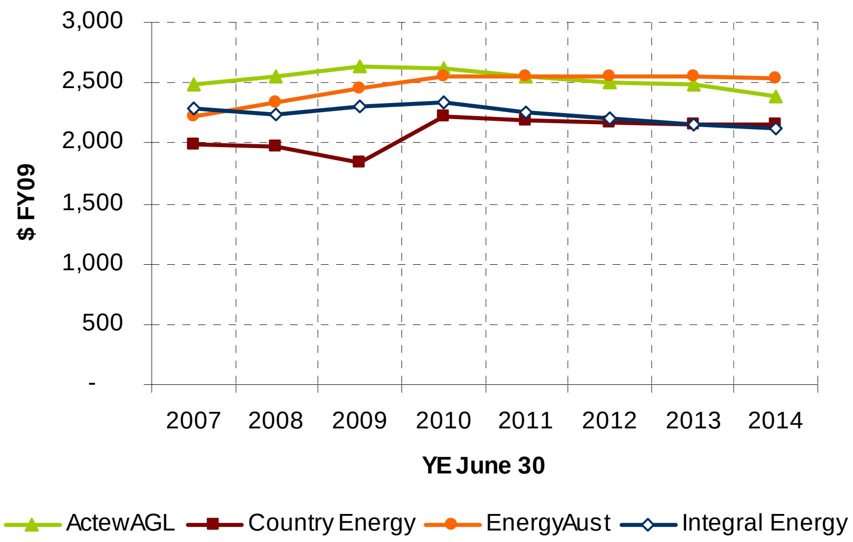
Movement in Opex from FY 2007

As also reported in volume 1, in order to look at the reasonableness of the forecast levels of total opex in the next period from a "top-down" perspective, we analysed the movements in opex that have taken place or are forecast by the ACT and NSW DNSPs to occur in the period from FY 2007 to FY 2014. The results are presented based on "opex per size" (to account for increases in the size of the businesses over the period). [74]

On the measure of "opex per size", EnergyAustralia's expenditure in FY 2010 (the first year of the next period) is 24% above that in FY 2007 and by FY 2014 is 34% above that in FY 2007. The rate of increase from FY 2007 to FY 2010 is higher than forecast by the other DNSPs.

We then assessed the movement in "opex per size" after removing the effects of real labour cost escalation. This reveals the increase in scope of opex activity over the period and the results are shown in Figure 9.3.

Figure 9.3: "Opex per Size" without Real Labour Cost Escalation



On this basis, EnergyAustralia's FY 2010 "opex per size" is 15% above the FY 2007 level and stays at that level during the next period. This means that during the next period, EnergyAustralia's cost efficiency relative to the other DNSPs will deteriorate.

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[74] It is appropriate to recognise that business costs will increase as the size of the business increases. We have used the composite size variable derived in Vol.1 as the measure used to account for size. Forecast customer numbers and maximum demands from the businesses regulatory information templates have been used over the period. No forecast of line km was available, so we have escalated this at the same growth rate as customer numbers.

The conclusion from the analysis of the movement in opex from FY2007 is that EnergyAustralia's opex increases at a much higher rate than other DNSPs and unless reasons can be established why EnergyAustralia should move further away from the industry norm, then the level of opex in the next period cannot be considered to be at an efficient level.

Summary of "Top-Down" Analysis

Whilst we accepted that each change on its own might be able to be justified, we nevertheless retained the view that adding increased costs to a base year without consideration of cost reductions in other parts of the business is likely to result in costs above an efficient level.

In summary, the comparative analysis shows that EnergyAustralia's base-year opex is close to but a little above the industry norm and can be considered an efficient starting-point for future forecasts. However, large increases forecast between FY 2007 and the start of the next period mean that EnergyAustralia's forecast for the next period may not be at an efficient level.

9.5 Review by Category ("Bottom-Up" Analysis)

Network Operating (Support) Expenditure

Table 9.5 shows current and forecast network operating (support) expenditure for the current and next periods.

Table 9.5: Current and Forecast Network Operating Expenditure ($ m 2009)

	Actual			Estimated		Proposed				
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Network control	15	15	16	17	18	19	19	20	21	23
Logistics & procurement	(6)	(8)	(4)	1	1	1	1	1	1	1
Insurance	4	4	5	6	6	6	6	6	6	6
Land tax	7	7	8	9	11	12	12	12	12	12
Executive management	2	2	2	3	3	3	3	3	3	3
IT planning, infrastructure and operations	28	25	31	39	49	59	63	62	64	66
Property management a/	19	19	20	23	29	32	32	31	32	29
Training and development b/	23	27	29	35	39	41	43	44	46	47
Other network operating	(1)	(0)	(1)	8	8	9	10	10	11	12
	90	**91**	**106**	**140**	**163**	**183**	**189**	**191**	**196**	**199**

Source: EnergyAustralia.
a/ Excluding land tax.
b/ Including apprentice training costs.

Expenditure in the next period is $957 m compared with $590 m in the current period, an increase of 62%. Network operating costs account for approximately 32% of Energy Australia's total opex for the next period. Average annual expenditure over the next period is projected to be $192 m, 63% above the base-year level after adjustment for the changes to the treatment of logistics, fleet and testing recoveries. [75] The biggest increases are in the sub-categories of IT (average annual expenditure 101% above the base year), training and development (54%), property management (53%), land tax (50%) and network control (28%).

[75] "Logistics and procurement" and other network operating costs move from credit to cost. We were advised these changes are due to a change in the way recoveries of logistics, testing and fleet costs are accounted for, and there are offsetting reductions in depreciation and capex.

Workload Escalators

We reviewed the workload escalators applied to network operating expenditure and considered them reasonable approximations of the increase in activity expected over the period.

Step Changes

As noted in section 9.3, EnergyAustralia has applied a large number of step changes to its base-year forecast based on expected business cost changes. The step changes applied to network operating costs are shown in Table 9.6. The majority relate to increases in operating costs resulting from capital investment on IT systems and property. The other major step change is for incremental apprenticeships.

Table 9.6: Step Changes - Network Operating Expenditure ($ m 2009)

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Business improvement team	0.2	0.0	0.0	0.0	0.0	0.0	0.0
IT applications - network system services	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Incremental AMI pilot	0.8	0.0	(0.0)	(0.2)	(0.2)	(0.2)	(0.1)
Incremental iAMS / field computing	0.0	4.0	0.0	0.0	0.0	0.0	0.0
Incremental data centre	0.0	0.8	0.0	0.0	0.0	0.0	0.0
Incremental IT capex (network sytems)	0.1	0.7	0.0	0.0	0.0	0.0	0.0
Incremental IT capex (corporate systems)	1.5	0.5	0.9	0.7	0.0	0.0	0.4
Incremental iAMS / field computing	1.7	0.7	2.0	0.0	0.0	0.0	0.0
Incremental IT capex (network systems)	0.0	0.0	1.2	2.1	(1.9)	0.1	0.9
Intelligent network - automation & comms	0.8	1.1	0.7	1.1	0.9	0.8	0.3
Property - system land tax	0.9	1.2	1.0	0.1	0.0	0.0	(0.0)
Property - system council rates	0.0	1.1	0.1	0.0	0.0	0.0	(0.0)
Property - system water rates	0.0	0.4	0.0	0.0	0.0	0.0	0.0
Incremental data centre	0.4	0.0	2.3	0.0	0.0	0.0	0.0
Incremental apprentice costs	4.2	2.7	1.3	0.6	0.5	0.0	0.0
Property - system maintenance	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Property - system rent	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Property - electricity	0.9	0.5	0.0	0.0	0.0	0.0	0.0
Property - non system maintenance	0.5	1.7	0.5	0.0	0.0	0.0	(2.4)
Property - non system rent	(0.0)	0.6	1.7	(0.2)	(1.0)	0.0	0.0
Property - environment	0.0	0.0	0.3	0.0	0.0	0.0	0.0
Information services	0.0	0.0	0.4	0.0	0.0	0.0	0.0
Corporate IT&T (CIO)	0.0	0.8	1.4	(1.4)	0.0	0.0	0.0
Insurance	1.3	0.1	0.0	0.0	0.0	0.0	0.0
Property - non-system land tax	0.2	0.1	0.4	0.1	(0.1)	(0.1)	(0.0)
Property - non-system council rates	(0.0)	0.2	0.2	(0.0)	(0.1)	(0.0)	0.0
Property - non-System water rates	0.0	(0.1)	0.0	(0.0)	(0.0)	(0.0)	0.0
Total	14.4	17.1	14.3	2.7	(1.8)	0.6	(1.0)
Cumulative total	**14.4**	**31.5**	**45.8**	**48.6**	**46.8**	**47.4**	**46.4**

Source: EnergyAustralia.

Due to their large number, we did not review each change individually except to consider whether it met the test of a valid step change as set out in section 9.3. We did not consider any of the step changes listed in the table met the test of being necessitated by a fundamental change in business activity due to factors outside the control of the business. However, we accepted the step change for incremental apprenticeships on the basis that this is fundamental to the delivery of the proposed capital and maintenance programme in the next period. An adjustment is proposed to remove the other step changes.

In making the adjustment, we recognised that real cost escalation and, in some cases, workload escalation, had been applied line by line in EnergyAustralia's model and we considered how this should be adjusted for when removing the step changes. We noted that most of the network operating step changes were project estimates and did not have workload escalation applied. In addition, we noted that the changes were mostly either contract costs (which do have real cost escalation applied) or other costs (which do not have real cost escalation at all). For practical reasons, we applied real cost escalation on the assumption that the step changes being removed were 50% contract-based and 50% other costs. The proposed adjustment is shown in Table 9.7.

Table 9.7: Step Change Adjustment - Network Operating Expenditure ($ m 2009)

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Total proposed	14.4	17.1	14.3	2.7	(1.8)	0.6	(1.0)
less incremental apprenticeship costs	(4.2)	(2.7)	(1.3)	(0.6)	(0.5)	0.0	0.0
Step changes to be removed	10.2	14.3	13.0	2.2	(2.3)	0.6	(1.0)
Cumulative total	10.2	24.5	37.5	39.7	37.4	38.0	37.0
Cost escalator			1.037	1.048	1.057	1.069	1.068
Escalated cumulative total			38.9	41.6	39.6	40.6	39.5
Proposed adjustment			**(38.9)**	**(41.6)**	**(39.6)**	**(40.6)**	**(39.5)**

Summary of Network Operating Expenditure

Large increases in network operating expenditure are proposed for the next period, primarily driven by step changes (increases) in IT and property costs. We considered that these step changes were not justified by external factors and should be offset by improvements in business efficiency. We accepted the step change in apprenticeships. An adjustment to remove the other step changes is proposed.

Network Maintenance Expenditure

Maintenance Policies and Practices

EnergyAustralia's maintenance strategy is outlined in its network management plan, asset management strategy and maintenance requirements analysis manual. [76] The practical outcomes of the asset management philosophy and analysis are documented in its technical maintenance plan. A "failure modes effects criticality analysis" and reliability-centred maintenance approach is used to determine maintenance practices and identify appropriate maintenance frequencies for each asset type. The rationale behind the approach is that the failure characteristics of an asset, in terms of risk and consequence, can be forecast with a reasonable level of confidence and EnergyAustralia has designed its maintenance programme around this analysis.

We asked for and received details on the use of the FMECA processes and reviewed examples applied to specific plant items.

We reviewed the plans and found the maintenance strategies and processes to reflect good practice in the electricity distribution industry in Australasia.

We also noted that EnergyAustralia had engaged Saha International to benchmark its asset management performance with a focus on maintenance and that Saha had concluded that the maintenance practices were relatively efficient. It found that "EnergyAustralia meets or exceeds best practice thresholds for asset management practices… [and its] current asset management regime ensures that maintenance programmes are optimised for both cost and asset performance". [77]

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[76] See attachments 4.2 and 9.2 of the proposal.

[77] See attachment 6.2 of the proposal.

Proposed Maintenance Expenditure

Table 9.8 shows current and forecast network maintenance expenditure for the current and next periods.

Table 9.8: Current and Forecast Maintenance Expenditure ($ m 2009)

	Actual			Estimated		Proposed				
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Inspection	69	72	76	81	85	89	92	97	101	107
Corrective	31	36	37	42	44	46	47	49	51	54
Breakdown	40	38	36	39	42	44	45	47	50	53
Nature induced and other	3	5	19	8	8	9	9	10	11	11
Other indirect syst. mtnce	22	21	22	28	31	32	33	34	35	36
	165	173	190	198	210	220	226	237	248	261
DNSP's adjustments										
Starting-point on curve				(1)	(2)	(2)	(3)	(4)	(5)	(6)
Asset age profile						(0)	(1)	(1)	(1)	(1)
Adjusted maintenance	**165**	**173**	**190**	**197**	**209**	**217**	**223**	**233**	**242**	**253**

Source: EnergyAustralia.

Expenditure after the adjustments advised by EnergyAustralia in the next period is forecast to be $1,167 m compared with $933 m in the current period, an increase of 25%. Maintenance costs account for approximately 40% of EnergyAustralia’s total opex for the next period. Average annual expenditure over the next period is $233 m, 30% above the base-year level after the effects of the 2007 storm ($10m) are removed. The increase is driven by escalation of 15% due to real cost increases and 11% due to workload escalation that, combined, account for most of the increase from the base year. There are some minor step changes amounting to around $4 m p.a. or 2% of the base level.

Workload Escalation

Workload escalation of maintenance activities has been based on the capex/opex trade-off model described in section 9.3. As noted, our view is that the relationship between age and maintenance stated by EnergyAustralia is not robust and may be overstated. The relationship results in a forecast increase relative to the normalised base year of approximately 11% in average maintenance costs over the next period. [78] By comparison, if the escalation were based on size, an increase of 7% would arise. [79] We note in this context that EnergyAustralia’s replacement capex in the next period averages $745 m p.a., corresponding to around 2.5% of the replacement cost of the asset base as estimated by EnergyAustralia. [80] This suggests that the increase in the average age of the assets will be stemmed in the next period. On the other hand, we note that the replacement capex is directed heavily at transmission, sub-transmission and zone substation assets, not at distribution assets where it is expected that many maintenance costs lie. Taking these factors into consideration, some increase above that attributable to size alone can be expected.

In the absence of better information, we took, as a reasonable estimate, an increase half way between the upper and lower bounds: that is, an increase of 9%. This results in an adjustment of $18 m over the next period. The calculation is shown in Table 9.9.

[78] This is after taking into account the adjustment of $23.5 m due to the changes in the starting-point and correction of assets age data advised by EnergyAustralia.

[79] Using the measure of size defined in footnote 63.

[80] Said to be $30-35 billion.

Table 9.9: Adjustment in Workload Escalation in Maintenance Expenditure

	Estimated		Proposed				
YE 30 June	2008	2009	2010	2011	2012	2013	2014
Mainteance escalator							
Annual growth	3.29%	2.95%	0.80%	0.79%	2.35%	1.68%	2.78%
Escalator	1.033	1.0634	1.0719	1.0803	1.1057	1.1243	1.1556
Size escalator							
Annual growth	1.31%	1.41%	1.55%	1.49%	1.46%	1.43%	1.41%
Escalator	1.013	1.0275	1.0434	1.059	1.0744	1.0898	1.1051
Mid-point							
Annual growth	2.30%	2.18%	1.17%	1.14%	1.90%	1.56%	2.09%
Escalator	1.023	1.0453	1.0576	1.0697	1.0901	1.107	1.1302
Mtce expenditure ($ m 2009)	197	209	217	223	233	242	253
Adjustment			**3**	**2**	**3**	**4**	**6**

Step Changes

Only two step-changes were proposed under maintenance activity, one to adjust for an unusually low level of activity in technical publications in the base year and the other in respect of an assessment of future claims for third party damage. These are shown in Table 9.10

Table 9.10: Step Changes - Maintenance Expenditure ($ m 2009)

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Technical publications and printing	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Third party damage	2.1	0.0	0.0	0.0	0.0	0.0	0.0
Total	3.1	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative total	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**

Source: EnergyAustralia.

We do not consider these step changes are necessitated by a fundamental change in activity due to factors outside the control of the business. We have therefore proposed an adjustment to remove them. As the amounts are relatively small, we have not applied cost or workload escalation to the adjustment.

Summary of Maintenance Expenditure

We are satisfied EnergyAustralia has appropriate maintenance policies and practices but two adjustments, one to remove step changes not considered justified and one to adjust the escalation due to asset ages, are recommended.

Other Operating (Business Support) Expenditure

Table 9.11 shows current and forecast other operating (business support) expenditure for the current and next period.

Table 9.11: Current and Forecast Other Operating Expenditure ($ m 2009)

	Actual			Estimated		Proposed				
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Customer operations	29	29	30	33	34	36	37	38	40	41
NVD, asset mngt etc a/	21	27	26	33	34	37	38	41	45	43
Divisional support	11	13	15	16	16	22	22	23	23	23
Customer support	9	4	4	4	4	4	4	4	5	5
Utilities services - metering	17	19	19	22	22	23	24	25	25	26
Debt management	1	1	1	1	1	1	1	1	1	1
Data operations	8	8	8	9	8	8	9	9	9	9
Divisional mgmt and other	(1)	1	1	0	0	0	0	0	0	0
Corporate finance function	16	18	20	21	23	24	24	24	25	25
Year-end adjstmts and other	(8)	39	(47)	0	0	0	0	0	0	0
	104	**158**	**79**	**137**	**143**	**155**	**159**	**165**	**172**	**172**

Source: EnergyAustralia.
a/ Includes netwrok venture development, asset management, major projects and engrg, metering and connections.

Expenditure in the next period is $824 m compared with $621 m in the current period, an increase of 33%. Other operating costs account for approximately 28% of EnergyAustralia's total opex for the period. Average annual expenditure over the next period is $165 m p.a., 31% above the base-year level after the effects of abnormal items are removed from the base year. EnergyAustralia stated that its corporate support costs have been allocated to the network business in accordance with the approved cost allocation method.

Workload Escalation

We accepted the workload escalators as reasonable approximations to the increase in activity expected over the period, except for the use of real system capex as a driver of workload increase in the asset management and project management division. As presented by EnergyAustralia, the large increases in capex drive similarly large increases in cost for these support activities that might not be appropriate. If the capex programme is driving these costs, they should be capitalised. However, irrespective of that, we do not consider that the relationship is as direct as assumed. In addition, project value is not necessarily an appropriate measure of the resource required to oversee work. This is confirmed by information on staff increases that does not show growth of the same magnitude as the capex programme. [81] We considered that the increases were overstated and, accordingly, we calculated an adjustment by applying an escalator based on forecast changes in the network division staff instead of real system capex. This results in an adjustment of $13 m over the next period. The calculation is shown in Table 9.12.

Table 9.12: Adjustment in Workload Escalation in Asset & Project Management

	Estimated		Proposed				
YE 30 June	2008	2009	2010	2011	2012	2013	2014
Real capex growth	4.6%	14.1%	47.6%	10.3%	16.5%	2.1%	-13.3%
Escalator	1.05	1.19	1.76	1.94	2.26	2.31	2.00
Network staff growth	6.6%	3.6%	2.8%	4.4%	-1.4%	1.1%	0.5%
Escalator	1.07	1.10	1.14	1.19	1.17	1.18	1.19
Adjustment factor	1.02	0.93	0.64	0.61	0.52	0.51	0.59
Proposed cost ($ m 2009)			5	6	7	7	6
Adjustment			**2**	**2**	**3**	**3**	**3**

81 See also the text in relation to this matter on p. 49, under the heading 'Impact of Workload Escalation'.

Step Changes

As in the case of network operating expenditure, EnergyAustralia has applied a large number of step changes to its base-year forecast based on expected business cost changes. The step changes applied in the other operating costs category are shown in Table 9.13.

Table 9.13: Step Changes - Other Operating Expenditure ($ m 2009)

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Customer relations - EWON Fee	0.0	0.3	0.0	0.0	0.0	0.0	0.0
Incremental meter reading - new customers	0.1	0.0	0.0	0.1	0.1	0.1	0.1
Incremental meter reading - conversions	0.1	0.1	0.1	0.1	0.1	0.1	0.1
NVD - telecommunications support	0.8	0.0	0.0	0.0	0.0	0.0	0.0
NVD - demand management initiatives	2.1	0.0	0.0	0.0	0.0	0.0	0.0
NVD - business systems operations	(0.2)	0.0	1.7	0.0	0.0	0.0	0.0
Finance and commercial - business systems	0.8	0.0	0.0	0.0	0.0	0.0	0.0
Network business - reliability & other	(0.8)	0.0	0.0	0.0	0.0	0.0	0.0
Metering projects (AMI and SPS)	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Metering and connections - GCSS claims	0.9	0.0	0.0	0.0	0.0	0.0	0.0
Metering and connections - policy, procedures	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Customer operations - emergency services	0.2	0.3	0.0	0.0	0.0	0.0	0.0
Customer operations - customer support	0.4	0.3	0.0	0.0	0.0	0.0	0.0
Incremental regulatory cycle	2.4	(1.6)	(1.3)	0.0	1.0	2.1	(1.5)
NVD - shared teleco infrastructure	0.0	1.3	0.4	0.0	0.0	0.0	0.0
Assymetric risk and self insurance	0.0	0.0	5.6	0.0	0.0	0.0	0.0
Corporate finance function	0.0	0.6	0.0	0.0	0.0	0.0	0.0
Corporate HR	0.0	0.7	0.0	0.0	0.0	0.0	0.0
Corporate secretariat	0.3	0.2	0.0	0.0	0.0	0.0	0.0
Media and internal communications	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Internal audit	0.0	0.2	0.0	0.0	0.0	0.0	0.0
Total	7.8	2.4	6.5	0.1	1.2	2.2	(1.6)
Cumulative total	**7.8**	**10.2**	**16.7**	**16.8**	**18.0**	**20.2**	**18.6**

Source: EnergyAustralia.

Due to their large number, we did not review each change individually, except to consider whether it met the test of a valid step change as set out in section 9.3. We considered that the impact of the regulatory cycle met the test and we were not required to review self-insurance. However, we did not consider that any of the other step changes in this list were necessitated by a change in activities outside the control of the business. We have therefore proposed an adjustment to remove them.

In making the adjustment, we recognised that real cost escalation and, in some cases, workload escalation, had been applied line by line in EnergyAustralia's model and we considered how this should be adjusted for when removing the step changes. We noted that the step changes in this expenditure category had a number of different cost and workload escalators applied. However, we found that the most common escalator applied was customer numbers with a variable component of around 90%. [82] We therefore made our adjustment based on 90% of customer number escalation and applied an equal ratio of the four costs escalators to calculate the impact of escalation on the step changes to be removed. The proposed adjustment is shown in Table 9.14.

[82] There was also a mixture of EGW labour, general labour, contract and other costs.

Table 9.14: Step Change Adjustment - Other Operating Expenditure ($ m 2009)

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Total proposed	7.8	2.4	6.5	0.1	1.2	2.2	(1.6)
less							
Incremental regulatory cycle	(2.4)	1.6	1.3	0.0	(1.0)	(2.1)	1.5
Assymetric risk and self insurance	0.0	0.0	(5.6)	0.0	0.0	0.0	0.0
Step changes to be removed	5.5	4.0	2.2	0.1	0.1	0.1	(0.1)
Cumulative total	5.5	9.5	11.7	11.8	12.0	12.1	12.0
Workload escalator			1.028	1.038	1.049	1.060	1.070
Cost escalator			1.072	1.087	1.106	1.128	1.138
Escalated cumulative total			12.9	13.4	13.9	14.5	14.7
Proposed adjustment			**(12.9)**	**(13.4)**	**(13.9)**	**(14.5)**	**(14.7)**

Summary of Other Operating Expenditure

Large increases in network operating expenditure are proposed for the next period, primarily driven by step increases in a variety of activities. Apart from the changes caused by regulatory reset requirements and self-insurance, we considered that none of the step changes was justified by external factors and that they should be offset by improvements in business efficiency. An adjustment to remove them is thus proposed. An adjustment is also proposed to the workload escalation applied to asset management and major projects expenditure.

9.6 Recommended Level of Opex

Summary of Considerations

In summary, EnergyAustralia's proposed opex has been reviewed in this section from a "top-down" and "bottom-up" standpoint.

The "top-down" analysis suggests that EnergyAustralia's base-year FY 2007 opex is at or a little above the industry norm, established by a variety of comparisons but could not be considered inefficient because of the limitations of benchmarking. However, the analysis of movements in opex from FY 2007 shows that EnergyAustralia's opex increases at a much higher rate than other DNSPs and unless reasons can be established why EnergyAustralia should move further away from an industry norm level of opex, then the level of opex in the next period cannot be considered to be at an efficient level.

The "bottom-up" analysis identifies numerous step changes that drive large increases in expenditure, particularly in the network support and business support categories.

We consider that a methodology such as that used by EnergyAustralia that starts with a base year and then applies cost escalators, workload escalators and step changes, without any consideration of business efficiency improvements or potential cost savings is likely to lead to a forecast of future costs that is above an efficient level.

We therefore consider that for acceptance as a step change, a cost ought to relate to a fundamental change in the business environment arising from outside factors, or be offset by cost efficiencies in other areas.

We have therefore proposed adjustments to remove most of the step changes proposed by EnergyAustralia.

Generally, we found the workload escalators used by EnergyAustralia to be a reasonable representation of expected workload changes over the next period except in two instances where an adjustment has been proposed.

Adjustment

The adjustment derived from the "bottom-up" analysis is shown in Table 9.15.

Table 9.15: Level of Opex Derived from "Bottom-Up" Analysis ($ m 2009)

YE 30 June	2010	2011	2012	2013	2014	Total
Opex proposed by DNSP	558	574	593	616	632	2,972
Capex/opex trade off reduction	(3)	(3)	(4)	(6)	(8)	(24)
	555	571	588	610	624	2,949
Proposed adjustments:						
Step changes						
- Network operating	(39)	(42)	(40)	(41)	(40)	(200)
- Mainteance	(3)	(3)	(3)	(3)	(3)	(15)
- Other operating	(13)	(13)	(14)	(14)	(15)	(69)
Workload escalation						
- Maintenance	(3)	(2)	(3)	(4)	(6)	(18)
- Asset & project management	(2)	(2)	(3)	(3)	(3)	(13)
	(60)	(62)	(63)	(65)	(65)	(316)
Pct of proposed opex	(11%)	(11%)	(11%)	(11%)	(10%)	(11%)
Adjusted "bottom-up" opex	**496**	**508**	**525**	**545**	**559**	**2,633**

The adjustment derived from the "top-down" analysis by applying cost escalation [83] and size escalation [84] to the base-year level is shown in Table 9.16.

Table 9.16: Level of Opex Derived from "Top-Down" Analysis ($ m 2009)

YE 30 June	2010	2011	2012	2013	2014	Total
Opex proposed by DNSP	558	574	593	616	632	2,972
Capex/opex trade off reduction	(3)	(3)	(4)	(6)	(8)	(24)
	555	571	588	610	624	2,949
Opex calculated by escalating base year by size growth:						
Normalised base year	423	423	423	423	423	2,117
Cost escalation	8%	9%	12%	14%	17%	
Size escalation	4%	6%	7%	9%	10%	
Calculated "top-down" opex	474	489	506	526	545	2,540
Reduction	(81)	(82)	(83)	(84)	(79)	(409)
Pct of proposed opex	(15%)	(14%)	(14%)	(14%)	(13%)	(14%)
Adjusted "top-down" opex	**474**	**489**	**506**	**526**	**545**	**2,540**

The level derived from the "top-down" analysis are 3% lower than the adjusted "bottom-up" level over the period. Considering that our comparative analysis showed that EnergyAustralia was operating at or slightly above the industry norm, the "top-down" calculation confirms that that the adjusted "bottom-up" level is not unreasonable. We therefore recommend that EnergyAustralia's proposed opex in the next period should be as shown in the bottom line of the "bottom-up" analysis in Table 9.15.

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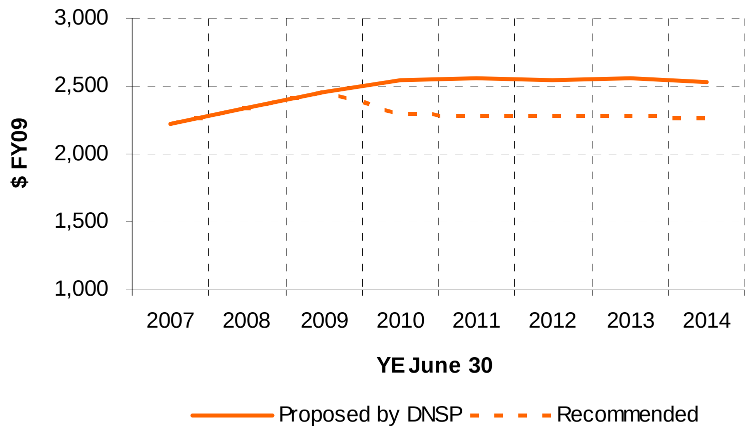
83 We have calculated an approximate weighted average escalation rate as described in volume 1 of this report.

84 We have used the composite size variable as defined in volume 1 of this report.

Effect of Adjustment

The effect of the recommended level of opex on distribution "opex per size" after adjustment for real labour cost escalation is illustrated in Figure 9.4.

Figure 9.4: "Opex per Size" without Real Labour Cost Escalation



Allocation to Transmission and Distribution

The adjustments proposed should be applied to transmission and distribution in the same ratio as EnergyAustralia's proposed expenditure. Thus, the recommended opex for transmission and distribution is as shown in Table 9.17.

Table 9.17: Recommended Level of Opex ($ m 2009)

Transmission

YE 30 June	2010	2011	2012	2013	2014
Network operating	13	14	14	14	15
Network maintenance	14	14	13	13	13
Other expenditure	5	5	5	5	5
	32	**32**	**32**	**33**	**33**

Distribution

YE 30 June	2010	2011	2012	2013	2014
Network operating	130	134	137	141	144
Network maintenance	197	204	213	222	232
Other expenditure	136	139	143	149	150
	463	**476**	**493**	**512**	**526**

10 Other Matters

10.1 Public Lighting Expenditure

We understand that the only alternative control service provided by EnergyAustralia is public lighting. EnergyAustralia's proposed capex and opex for this service in the next period compared with that in the current period is shown in Table 10.1.

Table 10.1: Public Lighting Expenditure ($ m 2009)

	Actual			Estimated		Proposed					Total in	Pct over
YE 30 June	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	'10-14	05-09
Capex	11	13	15	12	17	17	17	17	16	16	83	23%
Opex a/	9	12	10	12	14	14	15	15	15	16	75	30%

Source: EnergyAustralia's revised RIN template of 19 July 2008. Excludes any adjustments after that date.
a/ Exclusive of debt and equity raising costs.

We noted that EnergyAustralia's public lighting expenditure for FY 2004 to FY 2009 was reviewed by us for IPART in August 2005. EnergyAustralia's capex and opex were accepted by us at the time as reasonable, although there were a number of complicating factors in the work that we drew to IPART's attention.

The expenditure requested and approved in the 2005 review was $11.75 m p.a. for opex (*viz.* maintenance) in years FY 2006 to FY 2009 and $10 m in capex (including a major luminaire replacement programme) in years FY 2007 to FY 2009 (both in 2006 dollars). [85] Converted to 2009 dollars, these sums are approximately $12.7 m for opex [86] and $11.4 m for capex. [87] A comparison of these figures with EnergyAustralia's actual and projected expenditure (see Table 10.1 above) shows that opex has been less than the 2005 figure in all years to date but is projected to increase to $14 m in FY 2009 and to increase further in real terms over the next period. Capex has exceeded the 2005 figure in all years except FY 2005 and is projected to increase to $17 m in FY 2009 and to remain at or around that level until at least FY 2014.

In our 2005 review, we noted that (a) the level of capex was expected to be sustained for around eight years and was below a sustainable long-term level anyway and (b) some savings in opex ought to be realised after FY 2006. The rise in capex to date, evident from FY 2006 onwards, is consistent with those findings but the rise in opex is not.

We understand from our discussions with EnergyAustralia that the replacement programme foreseen in 2005 is continuing and on that basis, noting also the lack of materiality of this item in the overall context, we accept the capex forecast as reasonable. [88]

We also understood from our discussions with EnergyAustralia that the opex programme foreseen in 2005 was continuing but the savings foreseen by us are not evident. We noted, however, that the 2005 review specifically excluded any costs of compliance with the then draft public lighting code but accept that costs would be incurred on its introduction. The code has since been promulgated.

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85 $9 m in FY 2006.

86 Escalated for three years at an inflation rate of 2.5% p.a. for the purpose of this calculation.

87 Escalated for three years at 4.5% p.a. for capex for the purpose of this calculation (includes a real price increase of 2% to reflect the cost increases in materials, plus inflation).

88 A detailed review would be required of the type undertaken in 2005 of the figure is to be determined more accurately.

We did not discuss public lighting expenditure further with EnergyAustralia, given its lack of materiality in terms of the total expenditure reviewed, but if the AER continues a building block approach for public lighting, we recommend that the proposed capex be accepted but that in the absence of a case from EnergyAustralia for an increase, public lighting opex ought to be maintained at its level in FY 2008 in real terms.

10.2 Scope of Self-Insurance

It is common for electricity network businesses to carry their own insurance in certain respects, particularly where the risk of widespread loss is considered minimal, the premium for insurance is high or the deductibles or conditions attached to insurance cover make it worthless. We note from its proposal that EnergyAustralia proposes to self-insure against the following risks:

(a) workers' compensation,
(b) fraud,
(c) sabotage,
(d) insurer's credit risk,
(e) counter-party credit risk,
(f) general public liability,
(g) guaranteed customer service standards (GCSS) payments,
(h) bushfires,
(i) key person risk,
(j) risk of non-terrorist impact of planes and helicopters,
(k) risk of damage to poles and lines, and
(l) the risk of failure of substations and transformers.

These risks appear to be outside our field and so have not been reviewed. We note only that it is the prerogative of owners to determine their own risk appetite. [89]

We did not review the financial provisions associated with self-insurance but note that some of the costs of managing the risks listed above may be included or implicit in the base year (FY 2007) opex reported by the company or in its projections as normal business costs in the electricity distribution industry. We did check where possible to see whether any such events were included in the base-year expenditure but generally, it was not possible to determine this from the high-level information supplied.

10.3 Opex Deemed Uncontrollable in Benefit-Sharing Scheme

EnergyAustralia has not sought exclusions from the efficiency benefit-sharing scheme for any costs. (For the AER's guidance, we suggest that care is taken when defining the scheme to exclude expenditure relating to backlogs of work from the base year as any such expenditure should not form part of the opening balance in the calculation of future benefits.)

10.4 Additional Cost Pass-Through Events

Four general types of cost pass-through event are provided for in the Rules: regulatory change, service standard events, tax changes and instances of terrorism. [90] However, a DNSP may nominate additional cost pass-through events to apply in the next period and EnergyAustralia has proposed the following seven:

[89] Wilson Cook & Co does not advise clients on insurance matters.

[90] We understand that the Rules provide for an insurance pass-through event in the case of transmission determinations.

- dead zone events (*viz.* events occurring prior to the commencement of the next period but after EnergyAustralia's proposal was lodged),
- force majeure events,
- cost or demand input variance events (essentially, a proposal to index future expenditure for movements in demand and the cost of materials, but not labour),
- joint EnergyAustralia-TransGrid planning events,
- compliance events,
- customer connection events and
- a separation event (costs associated with the separation of EnergyAustralia's retail business).

As a general principle, we suggest that additional pass-through proposals are not to be recommended unless they are of a type that a prudent DNSP would not normally provide for in its expenditure estimates. We suggest that such proposals should meet a high threshold in that respect. In essence, we suggest that the potential events ought to be exceptional in nature. Normal or foreseeable business risks, including risks that an owner of the business ought to bear, should be excluded.

We have not reviewed the pass-through events proposed by EnergyAustralia as their assessment appears to be outside our field.

Other Possible Pass-Through Events

Finally, we were asked to say whether any other expenditure categories or items in the main capex projections would be more appropriately treated as pass-through events but no such cases were evident to us.

11 Conclusion and Recommendations

11.1 Opinion

Having considered the information received from EnergyAustralia and the factors required to be considered as summarised in this report, and based on that information, the representations made to us by EnergyAustralia and our own experience, our opinion in respect of EnergyAustralia's expenditure proposals is as stated below.

(a) EnergyAustralia's proposed capex from 1 July 2009 to 30 June 2014 including in respect of public lighting is considered to be prudent and efficient – see sections 7.3 (system capex), 8.3 (non-system capex) and 10.1 (public lighting expenditure) of this volume.

(b) EnergyAustralia's proposed opex from 1 July 2009 to 30 June 2014 including in respect of public lighting is considered to be prudent and efficient, subject to the adjustment proposed in sections 9.6 (opex) and 10.1 (public lighting expenditure) of this volume.

(c) We have no reason to suppose that EnergyAustralia will be unable to carry out its proposed programmes through a lack of resources – see section 7.2.

11.2 Matters for the AER's Consideration

In concluding this volume of the report in respect of EnergyAustralia, we would like to note the following matters for the AER's consideration:

- EnergyAustralia's adoption of 18 months of escalation (see page 28) and
- EnergyAustralia's interpretation of the licence conditions for feeder reliability (see page 39).

We would also like to note that although the proposed capex programme is large, it is likely to be followed by an even larger one in subsequent years as further strengthening in the CBD is undertaken and the programme of replacement of very old switchgear is accelerated.

11.3 Conditions Accompanying Our Opinion

Assessment Not an Assessment of Condition, Safety or Risk

Notwithstanding any other statements in this report, this review is not intended to be and does not purport to be an assessment of the condition, safety or risk of or associated with the assets and nothing in this report shall be taken to convey any such undertaking on our part to any party whatsoever.

All Earlier Advice Superseded

For the avoidance of doubt, we confirm that this report supersedes all previous advice from us on this matter, whether written or oral, and constitutes our sole statement on the matter.

Disclosure

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to it. No responsibility is accepted if full disclosure has not been made. No responsibility is accepted for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied directly or indirectly.

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Non-Publication

With the exception of its publication by the AER, in relation to its review of EnergyAustralia's expenditure proposals, neither the whole nor any part of this report may be included in any published document, circular or statement or published in any way without our prior written approval of the form and context in which it may appear.