Operating Expenditure Overview

30 April 2015

Operating Expenditure

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Approval and Document Control

VERSION	DATE	AUTHOR
1.0	30 April 2015	United Energy

Glossary

Abbreviations	
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
B2B	Business-to-Business
BFM	Bushfire Mitigation
BST	Base-Step-Trend
CATS	Consumer Administration and Transfer Solution
CRM	Customer Relationship Management
CROIC	Victorian Government Cost Recovery Order-in-Council
DMIA	Demand management incentive allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
EBSS	Efficiency Benefit Sharing Scheme
ECE	Effortless Customer Experience
EDPR	Electricity Distribution Price Review
EGWWS	Electricity, Gas, Water and Waste Services
ELC	Electric Line Clearance
EN	Embedded Networks
ENM	Embedded Network Manager
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EWOV	Energy and Water Ombudsman
FTE	Full Time Equivalent
GSL	Guaranteed Service Levels
ICT	Information and Communications Technology

Abbreviations	
IVR	Integrated Voice Response
LNSP	Local network service provider
M	Millions
MoU	Memorandum of understanding
MPB	Metering Provider for the installation provision and maintenance of metering installations
MTFP	Multilateral Total Factor Productivity
MW	Megawatt
NECF	National Energy Customer Framework event
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NMI	National Meter Identifier
Opex	Operating expenditure
PFP	Partial Factor Productivity
PV	Solar photovoltaic
RCM	Reliability Centred Maintenance
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test – Distribution
Rules	National Electricity Rules
SCER	Standing Council on Energy and Resources
SFA	Stochastic frontier analysis
STPIS	Service Target Performance Incentive Scheme
TFP	Total Factor Productivity
UE	United Energy
WPI	Wage Price Index

1. Purpose of this document

Operating expenditure (Opex) is the operating, maintenance and other non-capital expenditure that we incur to provide our distribution services to our customers.

This document explains and justifies our Opex for our Standard Control Services for the forthcoming regulatory period (1 January 2016 to 31 December 2020). Opex is one of the building blocks that is used to determine our annual revenue requirements.

Unless otherwise stated, our Opex is presented in real 2015 dollars and is expressed in total costs (i.e. direct costs plus escalations and overheads).

2. Structure of this document

This document is structured as follows:

- Section 3 details our Opex profile for the previous, current and forthcoming regulatory periods;
- Section 4 explains our actual Opex against the AER's allowance in the previous and current regulatory periods as well as the outcomes that it has delivered;
- Section 5 explains our forecasting methodology for Opex for the forthcoming regulatory period and justifies why we consider that it is the most reasonable methodology for regulatory forecasting;
- Section 6 details our Opex forecast for the forthcoming regulatory period;
- Section 7 explains how we consider that our Opex forecast meets the Opex objectives and criteria in clause 6.5.6 of the Rules, having regard for the Opex factors; and
- Section 8 details the supporting documentation relevant to our Opex forecast.

3. Expenditure profile

Our Opex for the previous, current and forthcoming regulatory periods is presented in Tables 1, 2 and 3 respectively.

Table 1 - Previous period Opex – Standard Control Services ($M, Real 2015)

	2006	2007	2008	2009	2010	TOTAL
Distribution Determination	108.8	111.1	113.4	115.9	115.6	564.8
Actual	106.3	100.1	103.0	102.3	109.1	520.8
Variance (Actual – Determination)	(2.6)	(11.0)	(10.4)	(13.6)	(6.5)	(44.1)

Table 2 - Current period Opex – Standard Control Services ($M, Real 2015)

	2011	2012	2013	2014	2015*	TOTAL
Distribution Determination	120.2	122.6	123.3	128.1	129.8	624.0
Actual / Estimated	134.6	134.9	121.4	125.6	126.3	642.8
Variance (Actual – Determination)	14.5	12.3	(1.9)	(2.5)	(3.4)	19.0

* Estimated

Table 3 - Forecast period Opex – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Opex forecast	157.7	159.1	159.9	162.6	161.1	800.4

Tables 1 and 2 show that we underspent the AER's Opex determination by about $44.1 million in the previous period and are expecting to spend very close to the AER's determination in the current period – we are projecting a small overspend of $19 million. Table 3 shows that we propose increasing our total Opex by $158 million, or 25 per cent, in the forthcoming regulatory period. This increase is largely due to an adjustment to our 2014 Opex base year for Opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period. This increases our base year Opex by $19 million. An explanation and justification for this Opex is provided in the Revenue Capped Metering Services Overview Paper.

4. Previous and current period expenditure

This section explains and justifies our actual Opex against the AER's allowance in the previous and current periods. It also demonstrates the efficiency of our Opex having regard for trend analysis of our Opex over time and benchmarking of our Opex against our peers.

4.1. Previous period 2006 to 2010

Table 4 below shows that:

- Our actual Opex was in a stable band between $100.1 million and $109.1 million per annum over the previous period, 2006 to 2010. This reflected the stability delivered by our contractual arrangements with our key Service Providers; and
- We consistently underspent against the Essential Services Commission of Victoria's (ESCV) Opex allowance – in total by $44.1 million over the regulatory period. This reflected the fact that we continually responded to the regulatory incentives provided by the ESCV.

4.2. Current period 2011 to 2015

Table 4 also shows that:

- We had a major increase in Opex from 2010 to 2011. This was attributable to:
  - A range of step changes that the AER approved in its Distribution Determination for the current period. These step changes total $10.6 million and related to:
    - Electricity Safety (Electric Line Clearance) Regulations;
    - Electricity Safety (Bushfire Mitigation) Regulations – Private Overhead Electric Lines;
    - Environmental Protection (Industrial Waste Resource) Regulations – Consultant Studies;
    - National Framework for distribution network planning and expansion;
    - Customer charter;
    - Customer communications;
    - Rectifying steady state voltage violations;
    - ZS power quality metering maintenance;
    - ZS secondary spares maintenance; and
    - The Energy Safe Victoria levy.
  - An internal business transformation project of $15 million. This was foreshadowed in our Regulatory Proposal and Revised Regulatory Proposal but was not accepted by the AER in its Distribution Determination. The costs involved implementing new business processes and systems, meeting the costs of redundancies associated with gaining efficiencies, so as to deliver greater cost reductions going forward, when compared with a projection of costs under the former business model.

  Given our Opex was above the AER's approved allowance we funded this overspend ourselves and its effect flows through to the benefit of customers under the efficiency benefit sharing scheme (EBSS) through the Efficiency Carryover Mechanism. Because this occurred early in the period – not in the penultimate year of the period – it will not flow through to our forecasts for the forthcoming regulatory period.
- Since 2012, we have steadily reduced our Opex as the internal business transformation has been completed. However, our Opex in 2013 was an anomaly and is not a representative base year going forward. This was recognised by the lower allowance that the AER made for 2013 and the step up it allowed in 2014. Our Opex in both 2013 and 2014 was lower than the AER's allowance;

- Over the current regulatory period we estimate that we will spend very close to the AER's total allowance – i.e. a small total overspend of $19 million. This shows that we are continuing to respond to the AER's incentives. We are forecasting a positive carryover adjustment under the Efficiency Carryover Mechanism in the forthcoming regulatory period of $27.7 million. We will therefore be sharing the benefits of our Opex efficiency with our customers over the forthcoming regulatory period; and
- In 2014, being the penultimate year of the current period that we are proposing to use as our base year for the forthcoming regulatory period, we underspent the AER's allowance by $2.5 million. This shows that we have not sought to "game" the regulatory framework by back-ending our Opex to inflate our proposal for the forthcoming regulatory period.

Table 4 – Previous and current period Opex, 2006 to 2015 – Standard Control Services ($M, Real 2015)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Distribution Determination	108.8	111.1	113.4	115.9	115.6	120.2	122.6	123.3	128.1	129.8
Actual / Estimated	106.3	100.1	103.0	102.3	109.1	134.6	134.9	121.4	125.6	126.3
Variance (Actual – Determination)	(2.6)	(11.0)	(10.4)	(13.6)	(6.5)	14.5	12.3	(1.9)	(2.5)	(3.4)

4.3. Benchmarking

We support the AER's use of benchmarking as part of its framework for assessing distribution network service providers (DNSPs') efficient Opex requirements.

Although limited forms of benchmarking have been used in previous Distribution Determinations, this is the first regulatory period that the AER will use a range of sophisticated econometric benchmarking techniques to assess our Opex requirements.

We have reviewed the benchmarking that the AER has undertaken in its 2014 Annual Benchmarking Report and in its recent Draft Distribution Determinations for the NSW and ACT DNSPs. We generally support the outcomes of this benchmarking, however there are some shortcomings in both the data that the AER has used and the way in which the benchmarking techniques have been applied.

We think that the AER has determined a "false frontier" by using average data for the 2006 to 2013 period. This is because, in effect, it uses a 2009 average frontier to assess the efficiency of Opex in 2014/15 without making appropriate adjustments for differences in DNSPs' operating conditions and obligations at these two points in time.

Further, we don't think that the AER has appropriately adjusted for differences in the way DNSPs' present their Opex. We, for example, are the only DNSP that does not capitalise any overheads. This has a profound impact on the Opex that we report and means that our Opex is not directly comparable to other DNSPs. Benchmarking should normalise for differences of this kind.

As a result of these kinds of limitations in both benchmarking data and techniques, we think care needs to be taken in applying benchmarking results to assess efficient Opex levels. In particular, it is appropriate to have regard to the balance of evidence provided by the various different benchmarking techniques, rather than placing too much emphasis on any single individual technique. By extension, the AER should not define the efficient frontier as being represented by a single business. Rather, it is more appropriate for the AER to group DNSPs in quartiles.

By its nature, there should be "winners" and "losers" from the use of benchmarking – not everyone should be a winner and not everyone should be a loser. DNSPs that are performing well relative to their peers should be recognised as performing efficiently, and rewarded accordingly. Businesses that are performing poorly relative to their peers should be transitioned to efficient levels of Opex over time. It is unrealistic to expect that all DNSPs can be performing at the same levels immediately. This complements the role of the EBSS as a key regulatory mechanism for facilitating this transition and recognises that, by its nature, achieving efficiency is a continuous journey.

All of the AER's benchmarking, as well as the benchmarking that we have commissioned ourselves, supports the view that we are an efficient DNSP and are in the top quartile of our peers. We have sustained this efficient performance over many years and are clearly responding to the incentives that the regulatory regime presents.

The AER's "Annual Benchmarking Report" released in November 2014 shows that we:

- Were the second most productive DNSP measured using Multilateral Total Factor Productivity (MTFP) analysis – this is illustrated in Figure 16 on page 31 of the Report;
- Are the third most productive DNSP measured using Partial Factor Productivity (PFP) of Opex – this is illustrated in Figure 19 on page 34 of the Report; and
- Have the second lowest Opex per customer (compared to density and line length) – this is illustrated in Figure 12 on page 24 and in Figure 26 on page 40 of the Report;
- Have the lowest total costs per customer (compared to density) – this is illustrated in Figure 14 on page 27 of the Report;
- Have the second lowest Opex per megawatt (MW) of maximum demand – this is illustrated in Figure 25 on page 39 of the Report.

Attachment 7 of the AER's Draft Distribution Determinations for the NSW and ACT DNSPs that was released in November 2015 focuses on Opex. It shows that we:

- Are the third most productive DNSP as measured using MTFP analysis – this is illustrated in Figure A.4 on page 7-58 of Attachment 7;
- Are in the top four most productive DNSPs as measured using a variety of different Opex MPFP techniques – this is illustrated in Figure A.5 on page 7-59 and Figure A.6 on page 7-64 of Attachment 7;
- Have the lowest total costs per customer (regardless of density) – this is illustrated in Figure A-7 on page 7-66 of Attachment 7; and
- Have the second lowest total Opex per customer (regardless of density) – this is illustrated in Figure A-8 on page 7-67 of Attachment 7.

In order to test the AER's benchmarking analysis, we commissioned Huegin to undertake its own independent analysis of our Opex using the same techniques that the AER used in their recent analysis. We have provided a copy of Huegin's report to the AER with this Regulatory Proposal.

Huegin applied the benchmarking framework and models currently favoured by the AER (provided by their consultant, Economic Insights) to the most recent data for United Energy. Huegin made the following findings:

- The stochastic frontier analysis (SFA) shows that we benchmark in the top four DNSPs and that our 2013 Opex is 2 per cent below the efficient frontier (where the frontier is calculated as a weighted average of the DNSPs with an efficiency score above 0.75);
- The Opex PFP analysis shows that we have the fourth highest Opex partial productivity score in 2013 and also the fourth highest average Opex partial productivity score over 2006 to 2013. Our Opex PFP in 2013 is 2 per cent better than the efficient frontier. The analysis indicates that our Opex PFP declined slightly since 2006, however we had a much smaller decline than other frontier businesses. We note that this decline does not take into account exogenous operating environment factors that affected our operations, including Opex step changes that occurred during this period, including those arising out of new regulatory obligations; and
- The category analysis indicates that our average Opex per customer between 2009 and 2013 is the second lowest of the DNSPs.

Importantly, the Opex in the AER's and Huegin's benchmarking analysis reflects the DNSPs' respective overhead capitalisation rates. The AER recognised in its Draft Distribution Determinations for the NSW and ACT DNSPs that "Capitalisation policies may affect the amount of Opex recorded". However, it did not make any allowance for this in its econometric modelling, although it did make an estimated adjustment to ActewAGL's efficiency score.

Huegin's analysis indicates that capitalisation rates vary markedly between DNSPs. It found that, on average, between 2009 and 2013 around one third of overheads were capitalised, with some DNSPs, including the frontier DNSP CitiPower, capitalising about 60 per cent of their overheads. In contrast, we do not capitalise any of our overheads. As a result, we include costs in our Opex that other DNSPs capitalise. This makes us look relatively less efficient when benchmarking Opex against other DNSPs. As the AER noted in its Draft Distribution Determination for the NSW DNSPs, this also means that we have a relatively high Opex to Capex ratio compared to our peers.

In order to highlight the sensitivity of benchmarking results to different assumptions and data, Huegin replicated the AER's results using its SFA and Opex PFP but adjusted all DNSPs' Opex to include capitalised overhead costs. Applying this change to the SFA resulted in us going from having the fourth highest efficiency score at a level two per cent below the efficient frontier to being the most efficient DNSP at a level well above the efficient frontier. In this way, Huegin found that our capitalisation policy has around a 14 per cent impact on our efficiency score. Huegin also found that we benchmark as the most efficient DNSP under Opex PFP analysis when capitalised overheads are included in all DNSPs' Opex.

Huegin's analysis therefore supports the overall outcomes of the AER's benchmarking analysis that we are one of the best performing DNSPs in the national electricity market (NEM).

We draw the following conclusions from the AER's and Huegin's independent benchmarking analysis:

- Our historical Opex is efficient and we are operating at or close to the efficient frontier of DNSPs in the NEM – certainly, we are in the top quartile of DNSPs in the NEM;

- Each of the benchmarking techniques shows that our Opex is efficient. We do not advocate relying on any one benchmarking technique, however the consistent body of benchmarking results supports this conclusion;
- We are the most efficient if capitalised overheads are included in all DNSPs' Opex;
- We are relatively efficient compared with our peers in spite of differences in our operating environment. We are an urban DNSP with significantly less underground network than CitiPower, who the AER has identified under some benchmarking techniques to be the frontier DNSP. We note that CitiPower enjoys the advantage of having a small network area and its overhead costs are therefore considerably lower than ours;
- We have sustained an efficient level of performance over a long period of time. We have not just arrived at our efficient levels of Opex recently. This means that assessments of our efficiency are not just a function of which year, or years, is chosen for the benchmarking analysis;
- Our new business model – that has resulted from our recent business transformation program – is successful and is delivering efficient Opex outcomes. This transformation provides a strong basis for us to continue to deliver efficient outcomes;
- We have continually responded to the incentives that the AER and, prior to this, the ESCV, have provided to us through the regulatory regime. This is reflected in the efficiency of our Opex and our customers are sharing in the associated benefits;
- We are delivering value for money to our customers through our efficient Opex; and
- Our 2014 Opex provides an efficient base year for determining our Opex forecast for the forthcoming regulatory period. There is no need for the AER to make any adjustment (over and above those that we have proposed) to our base year Opex. We discuss this further in section 6 below.

5. Opex forecasting method for forthcoming period

This section explains and justifies our method of forecasting Opex for the forthcoming regulatory period.

5.1. Choice of Base Step Trend (BST) forecasting method

We have used a BST approach to forecast our Opex for the forthcoming regulatory period. This is consistent with:

- The approach that we proposed in our Expenditure Forecasting Method that we submitted to the AER in May 2014;
- The AER's preferred approach for how it would like us to prepare our Opex forecast, as detailed in its Expenditure Forecast Assessment Guideline;
- The AER's preferred approach for how it will assess our Opex forecast, as detailed in its Expenditure Forecast Assessment Guideline; and
- The approach that the AER used in its November 2014 Draft Distribution Determinations to assess the NSW and ACT DNSPs' Opex forecasts that they submitted to the AER in their Regulatory Proposals in 2014.

5.2. Overview of BST approach

A BST approach involves forecasting our Opex at an aggregate level, rather than preparing individual forecasts for each category of Opex, as detailed in the AER's Annual RIN.

The starting point for the BST approach is that the incentive properties of the AER's EBSS mean that our base year Opex reflects prudent and efficient costs. This is because the efficiency carryover mechanism under the EBSS incentivises us to minimise our Opex, while ensuring that we continue to meet our regulatory obligations and to achieve our service performance targets.

The BST approach involves the following stages:

1. Nominating a base year;
2. Adding or subtracting, as relevant, adjustments to the base year Opex. These could include making adjustments for:
    a. Efficient incremental Opex in the final regulatory year of the current regulatory period;
    b. One off costs;
    c. Movements in provisions;
    d. Changes in service classification;
    e. Changes in cost allocation;
    f. Non-recurrent costs; and
    g. Efficiency adjustments.

    Applying these adjustments results in an efficient base year.
3. Applying rate of change adjustments to the efficient base year Opex for growth in:
    a. Real labour and non-labour prices;
    b. Output; and
    c. Productivity.

4. Adding or subtracting, as relevant, step changes (otherwise known as scope changes) to the efficient base year Opex.

The following section details how we have applied these four stages to achieve an efficient Opex forecast for the forthcoming regulatory period. It also explains how we have checked and tested our Opex forecast using the following other techniques to confirm that our Opex forecast is efficient:

- Trend analysis;
- The AER's Opex benchmarking; and
- Our own Opex benchmarking.

We have also ensured that our Opex forecast prepared using the BST approach aligns with our internal budget.

6. Expenditure forecasts and expected outcomes for forthcoming period

This section details our Opex forecast for the forthcoming regulatory period. We have derived our forecast by applying the BST forecasting method that is described in section 5.

6.1. Forecast Opex

Our Opex forecast for the forthcoming regulatory period is summarised in Table 5.

Table 5 - Forecast Opex – Standard Control Services ($M, Real 2015) *

	2016	2017	2018	2019	2020	TOTAL
Base	124.8	124.8	124.8	124.8	124.8	623.9
Base Year Adjustments	16.3	16.3	16.3	16.3	16.3	81.6
Output Growth	1.2	1.5	2.1	1.7	1.6	8.1
Price Growth	0.8	1.1	1.6	1.9	1.6	7.0
Productivity Growth	0.0	0.0	0.0	0.0	0.0	0.0
Step Changes	8.7	10.3	10.0	12.9	11.9	53.8
Guaranteed Service Levels	1.1	1.1	1.1	1.1	1.1	5.7
DMIS	2.4	1.3	1.1	1.1	0.8	6.6
Debt raising costs	2.5	2.6	2.7	2.9	3.0	13.7
Total	**157.7**	**159.1**	**159.9**	**162.6**	**161.1**	**800.4**

* Excludes shared assets and Efficiency Carryover Mechanism

Figure 1 illustrates how we have built-up our Opex forecasts for the regulatory period. It shows that we have:

- Started with our 2014 Opex;
- Applied certain Base Year adjustments;
- Added allowances for real price growth and output growth;
- Determined productivity savings to be zero;
- Added a number of significant adjustments for step changes in the forthcoming regulatory period; and
- Added provisions for Guaranteed Service Level (GSL) payments, debt raising costs and the DMIA.

We explain our rationale for this build up below.

Figure 1 - Forecast Opex – Standard Control Services ($M, Real 2015)

6.2. Efficient Base Year inclusive of Adjustments

We have chosen 2014 as our base year for our Opex forecast because:

- It is the most recent full regulatory year of actual reported expenditure at the time of preparing this Regulatory Proposal;
- It is representative of our underlying operating conditions in the current and forthcoming regulatory periods;
- It reflects the efficiencies that we have achieved in transitioning to our new business model;
- We benchmark at the efficient frontier compared with our peers; and
- It reflects our response to the incentives of the regulatory regime and shows that the incentives are working.

We have adjusted our 2014 Opex to achieve an efficient base year for the forthcoming regulatory period. We have:

- Added the share of our 2014 Opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period. An explanation and justification for this Opex is provided in the Revenue Capped Metering Services Overview Paper. This increases our base year Opex by $18.9 million;
- Removed our actual 2014 GSL payments of $1.15 million;
- Removed our DMIS expenditure of $0.7 million;
- Removed $1.5 million of costs for preparing our Regulatory Proposal for the forthcoming regulatory period because they are non-recurrent in nature; and
- Added $0.8 million in efficient incremental costs associated with the 2015 regulatory year, which we will be recurrent in the forthcoming regulatory period.

Table 6 details our efficient base year Opex, inclusive of these adjustments, for each year of the forthcoming regulatory period.

Table 6 - Efficient base year Opex including adjustments – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Efficient base year Opex including adjustments	141.1	141.1	141.1	141.1	141.1	705.6

6.3. Rate of change – output

We have included an allowance in our Opex forecast for the impact of output growth in the forthcoming regulatory period. This reflects the fact that greater output costs more to operate and maintain.

We have applied the output change measures and respective weightings that the AER used in its November 2014 Draft Distribution Determination for the NSW and ACT DNSPs' Opex for their forthcoming regulatory period, being:

- Customer numbers (67.6 per cent);
- Circuit length (10.7 per cent); and
- Ratcheted maximum demand (21.7 per cent).

Table 7 details our forecast Opex increase attributable to the impact of output growth in the forthcoming regulatory period.

Table 7 - Rate of change – output – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Output Growth	1.2	1.5	2.1	1.7	1.6	8.1

6.4. Rate of change – price

We expect that the costs of two inputs – labour and materials – will increase by more than the consumer price index (CPI) in the forthcoming regulatory period. Costs of other inputs are assumed to increase in line with the CPI.

We have only adjusted our Opex forecast for real price growth in labour in the forthcoming regulatory period. This is because materials comprise only a small component of our Opex. We therefore expect that real price growth in materials will not have a significant impact on our Opex in the forthcoming regulatory period.

The AER adopted a weighting of 62 per cent for labour and 38 per cent non-labour in its November 2014 Draft Distribution Determination for the purposes of determining the rate of price change for the NSW and ACT DNSPs' Opex for their forthcoming regulatory period. We have adopted these same percentages to determine the real price growth for our Opex forecast for our forthcoming regulatory period.

We engaged an independent expert, BIS Shrapnel, to forecast real labour cost escalations relevant to our Opex for the forthcoming regulatory period. We have provided a copy of their report to the AER with this Regulatory Proposal.

BIS Shrapnel is a highly-regarded economic forecaster. As it notes in its report, BIS Shrapnel "won acclaim for correctly forecasting the domestic downturn in 2000/01; the subsequent boom in business investment and the chronic labour and capacity constraints by mid-decade; the rise in interest rates through 2006 to 2008, including picking the peak in housing interest rates in mid 2008; and was virtually alone in forecasting that Australia would not suffer a recession during the global financial crisis".

BIS Shrapnel prepared its forecasts using top-down and bottom-up approaches. Its bottom-up approach models industry sectors at a regional and individual category level, which are aggregated to a national level. The top-down modelling reconciles the bottom-up forecasts with prevailing trends, investment and business cycles and assumptions about the general macroeconomic outlook. BIS Shrapnel is forecasting that:

- Wages in the Australian Electricity, Gas, Water and Waste Services (EGWWS or 'Utilities) sector will slightly exceed the all industry result, given the utilities sector generally has employees with higher skill, productivity and wage levels than most other sectors; and
- Utilities wages in Victoria will average the same as nationwide wages over the forthcoming regulatory period. This is primarily due to the similar outlook for utilities engineering construction within Victoria and Australia.

BIS Shrapnel's forecasts of growth in the Wage Price Index (WPI) are detailed in Table 8 below.

Table 8 - Real rate of change – labour price (WPI) – Standard Control Services (per cent)

		2016	2017	2018	2019	2020	Average
Labour	Electricity, Gas, Water and Waste Services	0.9	1.3	1.8	2.1	1.8	1.6
	Contractor	1.2	1.6	1.5	1.6	1.9	1.6

Source – BIS Shrapnel, "Real Labour and Material Cost Escalation Forecasts to 2020 – Australia and Victoria, Final Report", November 2014, page ii

We applied the BIS Shrapnel labour cost escalators to our mix of employees and contractors to determine our forecast real labour cost increases.

Table 9 details our forecast Opex increase attributable to real labour price growth in the forthcoming regulatory period.

Table 9 - Real rate of change – labour price – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Real Price Growth	0.8	1.1	1.6	1.9	1.6	7.0

6.4.1. Rate of change – productivity

We have determined a rate of change productivity adjustment of zero per cent for each of the five years of the forthcoming regulatory period. This is consistent with the AER's position in its Draft Determination for the NSW and ACT DNSPs, where it stated:

> *We have applied a zero per cent productivity change in estimating our overall rate of change. This is based on Economic Insights' recommendation to apply zero productivity change for the NSW and ACT distribution network service providers and our assessment of overall productivity trends for the forecast period.*[1]

Economic Insights' recommendation that the AER referred to stated:

> *We are of the view that a forecast Opex productivity growth rate of zero should be used in the rate of change formula. There is a reasonable prospect of Opex productivity growth moving from negative productivity growth towards zero change in productivity in the next few years as energy use and maximum demand stabilise, given the excess capacity that will exist in the short to medium term and as the impact of abnormal one–off step changes recedes. It should also be noted that recent historic negative measured Opex productivity growth rates include the effects of some significant step changes included in previous resets.*[2]

We consider that this logic applies equally to our network. Further, we note that we are the only network in the NEM that has maintained its productivity performance over time (relative to the AER's frontier) and therefore should not be penalised for overall industry negative productivity in recent years.

[1] AER, "Ausgrid draft decision - Attachment 7: Operating expenditure", November 2014, page 7-154

[2] Economic Insights, "Economic Benchmarking of NSW and ACT DNSP Opex", 17 November 2014, page 57

Table 10 - Rate of change – productivity – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Productivity Growth	0.0	0.0	0.0	0.0	0.0	0.0

6.5. Step change

We have included an allowance in our Opex forecast for a range of step changes for events or obligations that will cause us to incur additional costs over and above the efficient base year in the forthcoming regulatory period that we did not incur in the current regulatory period. In its Expenditure Forecast Assessment Guideline, the AER indicated that step changes should relate to either changes in regulatory obligations or Capex-Opex trade-offs. Accordingly, we have grouped our proposed step changes as follows:

a. *New regulatory obligations - annual* – these step changes arise from new on-going, externally-imposed regulatory obligations that require us to increase our Opex in each year of the forthcoming regulatory period;

b. *Customer response / initiated* – these step changes respond to specific customer requests or needs that are not reflected in our base year Opex;

c. *Existing regulatory obligations - recurrent but non-annual* – these step changes arise from existing regulatory obligations that, because they are recurrent but non-annual in nature, are not reflected in our base year Opex. We need to address them by increasing our Opex in particular years of the forthcoming regulatory period;

d. *Change in external environment – annual* – these step changes respond to significant exogenous changes that are not reflected in our base year Opex that unavoidably cause annual increases in our Opex; and

e. *Capex-Opex trade-off* – this step change relates to movements between our Capex and Opex, as is contemplated in the AER’s discussion of step changes in its Expenditure Forecast Assessment Guidelines.

Table 11 shows that of our total Step Changes of $53.8 million: $23.8 million (44 per cent) relates to new regulatory obligations; $12 million (22 per cent) relates to existing regulatory obligations; and $6.4 million (12 per cent) relates to changes in our external environment. Only $11.2 million (20 per cent) relates to factors that we can effectively control, being Capex-Opex trade-offs and responses to our customers.

Table 11 – Step changes – Standard Control Services ($M, Real 2015) - numbers may not add due to rounding

New regulatory obligations – annual			2016	2017	2018	2019	2020	Total
1.	a.	Power of Choice – Metering Competition	1.2	0.5	0.6	0.6	0.6	3.5
	b.	Power of Choice – Customer Access to Data	0.3	0.3	0.3	0.3	0.3	1.7
	c.	Power of Choice – Embedded Network	0.1	0.1	0.1	0.1	0.1	0.7
	d.	Power of Choice – Demand Management IT Platform	-	-	-	0.8	0.8	1.6
	e.	Power of Choice – Network (Chapter 5 and Chapter 5A – Embedded Generation Connection, including Solar)	0.7	0.7	0.7	0.7	0.7	3.5
2.		Regulatory Information Notice reporting	-	0.4	0.4	0.4	0.4	1.6
3.	a.	Energy Safe Victoria safety obligations	0.2	0.2	0.2	0.2	0.2	1.0
	b.	Energy Safe Victoria rule changes	1.7	1.7	1.7	1.7	1.7	8.7
		Sub-total	**4.3**	**4.0**	**4.0**	**4.9**	**4.9**	**22.2**
Customer response / initiated								
4.	a.	Effortless Customer Experience Program	1.6	1.5	1.0	1.0	1.0	6.0
	b.	Stakeholder engagement	0.3	0.3	0.3	0.3	0.3	1.3
	c.	Council trees	-	1.0	1.0	1.0	-	3.0
		Sub-total	**1.9**	**2.7**	**2.2**	**2.2**	**1.2**	**10.3**
Existing regulatory obligations – recurrent but non-annual								
5.		Customer charter	-	0.7	-	-	-	0.7
6.		Regulatory submission cost	-	-	-	1.5	0.8	2.3
7.	a.	Neutral Testing	-	0.1	0.1	0.1	0.1	0.4
	b.	Network Planning and Analytics - IT Capital Program	-	-	0.8	1.2	2.1	4.1
8.		Guideline 11 EWOV Direction	0.9	0.9	0.9	0.9	0.9	4.5
		Sub-total	**0.9**	**1.7**	**1.8**	**3.7**	**3.9**	**12.0**
Change in external environment – annual								
9.		IT security costs	0.7	0.8	0.8	0.8	0.8	4.0
10.		Insurance premiums	0.3	0.4	0.5	0.6	0.7	2.3
		Sub-total	**1.0**	**1.2**	**1.3**	**1.4**	**1.5**	**6.4**
Capex-Opex trade-off								
11.		Pole top inspection	0.6	0.6	0.6	0.5	0.2	2.4
Real price escalations								
			0.0	0.1	0.1	0.2	0.1	0.5
Total Step Changes			8.7	10.3	10.0	12.9	11.9	53.8

We set out in the following tables a detailed explanation of each of our step changes.

<table>
<tr><td>Name</td><td colspan="6">1a. Power of Choice – Metering Competition</td></tr>
<tr><td rowspan="2">Amount ($M, Real 2015) - numbers may not add due to rounding</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>Total</td></tr>
<tr><td>1.2</td><td>0.5</td><td>0.6</td><td>0.6</td><td>0.6</td><td>3.5</td></tr>
<tr><td>Description</td><td colspan="6">We will incur additional costs for the establishment of new processes required to support the introduction of metering competition. We will also incur costs for additional staff to manage the new requirements including:
• Enabling competition for all types of meters we that currently manage;
• Facilitating a new Metering Coordinator role in the NEM;
• Managing increased new connections activities resulting from metering competition;
• Managing increased activities in meter data collection resulting from the increased number of meter providers in the market;
• Managing increased number of claims associated with metering and network issues due to increased meter churn activities; and
• Managing additional meter data storage and transfer requirements.</td></tr>
<tr><td>Timing of when step change will commence</td><td colspan="6">We expect that the rules supporting the introduction of Power of Choice will be effective from 1 January 2017. We have assumed that setup will occur in 2016 and the required additional staff will commence in November 2016 to be ready for the new rule changes.</td></tr>
<tr><td>Recurrent / on-going or one-off</td><td colspan="6">There will be a one-off cost of $1 million to establish new processes as well as ongoing staff costs to manage new processes. This is based on:
• Managing local network service provider (LNSP) obligations in relation to meter churn activities, such as site and meter location details provision where requested by third party metering providers (MPB). This is based on the assumption of around 2,000 meter transfers per month;
• One additional staff member to assist with increased complexity in relation to connection, metering and energisation tasks, to ensure that new connections are appropriately established in our systems, to establish data-streams and to assist with the network tariff components;
• One additional staff member in the Network Meter Data Management Team (back office provider) to follow up third party meter providers on metering data that is not received or that is not accurate so as to ensure that our network bills can be issued. This includes cancelling and rebilling caused by timing issues with delayed meter notifications and network billing cycles and meter set up by third party metering installations (AEGIS); and
• One field based metering auditor to ensure that third party meter providers are installing meters safely in our network and not causing any network related issues as a result of the meter installation by third parties.</td></tr>
<tr><td>Driver:
(a) External - regulatory change; safety change; or stakeholder driven; or
(b) Internal - Capex / Opex trade-off; or effortless customer experience</td><td colspan="6">The driver for these costs is an external regulatory change.</td></tr>
<tr><td>If driver (a) above, in the current period were:
(a) Any relevant variations or exemptions granted; or
(b) Compliance audits undertaken?</td><td colspan="6">Not applicable.</td></tr>
<tr><td>Explain / justify why required and why not covered in rest of Opex forecast</td><td colspan="6">These establishment and ongoing staff costs are not required if the Power of Choice – metering competition rule changes do not proceed. As the rules and procedures for the introduction of metering competition are still unclear and have not yet been implemented, these costs are not included in our base Opex forecast.</td></tr>
<tr><td>Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken</td><td colspan="6">The process for calculation of costs are as follows:
• Set up costs – based on $0.5 million to set up new processes for Meter Coordinator role and $0.5 million for obtaining accreditation to act as a Metering Coordinator in the NEM</td></tr>
</table>

Name	1a. Power of Choice – Metering Competition
	• **Staff Costs (Back Office Provider)** – Two full time equivalent staff (FTE) at Aegis (Back office provider) commencing November 2016 at $7,366 per month per FTE • **Staff Costs (Field Auditing)** – One internal FTE within Metering Team commencing in 1 January 2016 at $130,000 per annum to establish a third party audit program and carry out field based audits of third party meter providers • **Claims** – additional costs associated with the cost to repair/replace estimated at $500 per customer with volume increased by 10 per cent ($50,000 in 2016, increasing to $180,000 by 2020) as non-United Energy meters are installed • **Data Storage** – additional data storage costs associated with the management, storage and archiving of metering data as a result of additional third party service providers ($100,000 from 2017). • **Audit** – Ongoing AEMO audit costs estimated at $25,000 per annum commencing in 2017 based on current audit costs for existing AEMO audits.

<table>
<tr><th>Name</th><th colspan="6">1b. Power of Choice – Customer Access to Data</th></tr>
<tr><td rowspan="2">Total Amount ($M, Real 2015) - numbers may not add due to rounding</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>Total</td></tr>
<tr><td>0.3</td><td>0.3</td><td>0.3</td><td>0.3</td><td>0.3</td><td>1.7</td></tr>
<tr><td>Description</td><td colspan="6">We will incur additional costs to allow customers (or their agents) to obtain their electricity consumption data from us in addition to their retailer as required, to meet the regulatory obligations introduced under the ‘Power of Choice’ reforms. The additional costs are to:
• Support a new and/or upgraded IT system to cater for data provision for all meter types; and
• Establish and manage new processes.</td></tr>
<tr><td>Timing of when step change will commence</td><td colspan="6">The new rule became effective under the Rules from 1 December 2014, although will not be introduced into the National Energy Retail Rules (which require DNSPs to better facilitate customer or authorised representatives with access to information) until 1 September 2015.</td></tr>
<tr><td>Recurrent / on-going or one-off</td><td colspan="6">Costs will be ongoing costs to cover:
• Two additional members of staff to manage additional data requests; and
• Continuing support and maintenance of a new or upgraded IT system.</td></tr>
<tr><td>Driver:
(a) External - regulatory change; safety change; or stakeholder driven; or
(b) Internal - Capex / Opex trade-off; or effortless customer experience</td><td colspan="6">The driver for these costs is an external regulatory change.</td></tr>
<tr><td>If driver (a) above, in the current period were:
(a) Any relevant variations or exemptions granted; or
(b) Compliance audits undertaken?</td><td colspan="6">Not applicable</td></tr>
<tr><td>Explain / justify why required and why not covered in rest of Opex forecast</td><td colspan="6">We have already implemented a ‘customer portal’ which provides usage information to customers. However, this existing customer portal was only implemented as a pilot for advanced metering infrastructure (AMI) meters and has a relatively limited number of users. In addition, the existing system does not address all of the new regulatory requirements.
To meet the new regulatory obligations, we will therefore either carry out a significant upgrade to the existing customer portal or implement a new system.</td></tr>
</table>

Name	1b. Power of Choice – Customer Access to Data
	Additional support services, and therefore operating expenditure, will be required to support the upgraded/new system with the expected increase in the number of users. Additional business operations staff will also be required to establish and manage new processes. These costs would not have been incurred if the new regulatory requirement had not been introduced. These costs are not required until new rules come into effect. As the rules for this change do not come into effect until late 2014, these costs have not been included in our base Opex forecast.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The process for calculation of business operations costs is based on the estimated number of staff required to provide data to customers (estimated at one FTE) at the existing contracted rate per FTE with Aegis (our back office service provider) of $7,366 per month (approximately $88,000 per annum). The process for calculation of IT operations costs is based on the estimated number of staff required to support the new or upgraded system (estimated at one FTE) at the existing contracted rate per FTE with our IT application support provider. The forecast cost increase is based on the assessment that our current applications support service provider will require one additional full time resource, during business hours at a cost of $272,000 to support the new system. When adjusted for Standard Control Service / Alternative Control Service, the Standard Control Service step change is $258,000. The assessment of alternative IT solutions to meet the regulatory requirement is presented in our document 'PJ 19 Project Justification – Power of Choice – Consumer Data Access'. It should be noted that the selection of solution and the estimated Opex increase, is based on assumptions about the likely requirements. The requirements had not been finalised at the time that these estimates were developed. If the requirements vary from those assumed, there could be a significant change in both the capital costs to implement the IT system and in the ongoing operating costs of the system.

Name	1c. Power of Choice – Embedded Network					
Amount ($M, Real 2015) - numbers may not add due to rounding	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
	0.1	0.1	0.1	0.1	0.1	0.7
Description	Costs required for one FTE to liaise with Embedded Network Managers (ENM) operating on our distribution area to clarify metering and other arrangements for consumers in embedded networks (EN), reduce the barriers to consumer access to competitive offers from market participants and support competition in the provision of electricity and demand side services.					
Timing of when step change will commence	The rule for EN is currently with the Australian Energy Market Commission (AEMC) and is anticipated to be in place in 2015.					
Recurrent / on-going or one-off	Ongoing costs to cover cost of one FTE to liaise with the new Embedded Network Managers operating in our distribution area.					
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	The driver for these costs is an external regulatory change. The new rule will require the following changes to our systems and processes: • Register new ENM participants as required after notification by AEMO. This will include managing changes in IT systems and gateways to reflect a new participant in much the same manner as new entrant retailers • Manage increased levels of ENs, ENMs and parent name assignment. Manage the necessary amendments in national meter identifier (NMI) standing data and seek update to AEMO EN naming tables as required; • Implement the amendments to Business-to-Business (B2B) and Consumer Administration and Transfer Solution (CATS) procedures that arise from new participant roles. Manage any increased levels of failed transactions regarding requests, notifications and completions arising from amongst other things the new role, role churn at a connection and name changes; • Understand and manage the implications from the new ENM service level procedure and the ENM guide and impacts on connection and energisation; and • Manage the subtractive or other arrangements for metering that may impact on the parent meter data, our network billing accuracy and the various regulatory threshold management processes. The new FTE would be required to manage the above for both new greenfields EN and also for any existing EN which transfer to these new arrangements.					

Name	1c. Power of Choice – Embedded Network
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	Not applicable.
Explain / justify why required and why not covered in rest of Opex forecast	These costs are not required until new rules come into effect. As the rules for this change have not yet come into effect, these costs have not been included in our base Opex forecast.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The process for calculation of costs is based on one additional internal FTE at a total remuneration cost of $130,000 per annum.

Name	1d. Power of Choice – Demand Management IT Capital Program					
Amount ($M, Real 2015) - numbers may not add due to rounding	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
	-	-	-	0.8	0.8	1.6
Description	Costs for the support and maintenance of a new and/or upgraded systems implemented to: • Enable demand response to be managed from enrolment of customers through event execution and settlement • Provide demand-side participation information to AEMO.					
Timing of when step change will commence	The timing is dependent on a number of factors including the finalisation of the AEMC's rule changes relating to demand reporting and the rate at which customers adopt demand management offerings. The assumption is that the new platform will be implemented in 2018 and the increased Opex will be incurred from 2019 onwards.					
Recurrent / on-going or one-off	This is an ongoing cost required for the continuing support and maintenance of new systems.					
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	(a) External - Regulatory Change – the new Demand Management Platform will enable us to meet demand management reporting requirements defined in the proposed AEMC 'Power of Choice' rule changes. The AEMC's rule change on Demand Management Information is likely to be made in 2015 with an 18 month window for AEMO to develop new demand management information Guidelines. Prior to the implementation of the new platform, we will meet reporting requirements using manual processes and interim solutions. However, as customer take-up of demand services increases, manual processes will not be practicable and the new platform will be required. The new Demand Management Platform will also enable us to deploy demand management as a cost-effective alternative to traditional network investment. This capability includes a system to manage the end to end Demand Response (DR) process in support of business-as-usual and Demand Management Incentive Scheme (DMIS) demand management activities.					
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	N/A					
Explain / justify why required and why not covered in rest of Opex forecast	Operating demand management services and providing detailed reports at volume is a new capability for us. The solution, as planned, will require new hardware and vendor-provided software. As a result there will be an increase in IT Opex associated with hardware and software maintenance and support (or in service fees if a cloud solution is adopted).					

Name	1d. Power of Choice – Demand Management IT Capital Program
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The capital and operating costs for the Demand Management Platform Project are outlined in the documents 'PJ 25 Project Justification – Demand Management IT Platform AEMO Reporting' and 'PJ26 Project Justification – Demand Management IT Platform – Demand Management'. The Opex impact of the implementation of the new system is as follows: • Hardware Maintenance and support - $0.132 million per annum (based on 20 per cent of the original hardware purchase price per annum) • Software Maintenance – $0.242 million per annum (based on 22 per cent of original software purchase price per annum) • Application support – $0.48 million per annum (based on the cost of a support team of two FTEs at the rates defined in the existing contract between us and the application support service provider). The above costs produce the requirement for a Standard Control Services Opex Step Change of $0.8 million per annum (after Standard Control Services / Alternative Control Services allocation).

Name	1e. Power of Choice - Network (Chapter 5 and 5A Rule Change – Embedded Generation Connection, including Solar)					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	0.7	0.7	0.7	0.7	0.7	3.5
Description	Cost of four additional resources required to meet changes to the Rules and to manage customer requests for the uptake of embedded generation.					
Timing of when step change will commence	The costs of this step change are not reflected in the 2014 base year Opex. They will commence in 2015 and 2016 given that: • Changes to Chapter 5 of the Rules commenced on 1 October 2014 and changes to Chapter 5A of the Rules are expected to commence in Victoria on 1 January 2016; and • All market indications are pointing towards continued growth in the uptake of embedded generation throughout the forthcoming coming regulatory period.					
Recurrent / on-going or one-off	The step change will be recurrent given that it relates to on-going regulatory changes and is predicated on on-going growth in the uptake of embedded generation.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	There are two related external drivers of this step change – regulatory change and changes in the market for embedded generation. They impose increased obligations on us to comply with our regulatory obligations and to meet our customers' needs. The changes to Chapter 5 apply to embedded generators above 5MW as well as, in some circumstances, those below 5MW. The changes to Chapter 5A apply to embedded generators below 5MW. They require us to: • Publish an 'information pack' setting out information to guide embedded generators on matters such as the process requirements and potential costs; • Follow new connection enquiry and application processes; • Publish registers of generating plant that has been successfully connected to the network in the preceding five years; • Follow the dispute resolution process in accordance with Chapter 8 of the Rules. The use of distributed embedded generation is increasing in our service area, stimulated by decreasing technology cost, commercial competitiveness, and increased environmental awareness. AEMO's 2014 "National Electricity Forecasting Report" is forecasting 24 per cent annual growth in national rooftop solar photovoltaic (PV) installations to 2016-17, with the strongest growth occurring in Victoria and Queensland. We expect that this growth will also be promoted by further Rule changes that the AEMC has recommended to Standing Council on Energy and Resources (SCER) in the context of the Power of Choice reforms, which are designed to incentivise demand management and embedded generation uptake. However, the exact nature and timing of these Rule changes are uncertain at the time of submitting this Regulatory Proposal.					
If driver (a) above, in the current period were:	Not applicable.					

Name	1e. Power of Choice - Network (Chapter 5 and 5A Rule Change – Embedded Generation Connection, including Solar)
(a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	
Explain / justify why required and why not covered in rest of Opex forecast	We expect that the Rule changes, and the related significant increases in the use of distributed embedded generation, will drive major changes to many aspects of our 'business as usual' activity. In particular, there will be: • Condensed and prescriptive timeframes for us to accommodate proponent connection proposals (which are designed to enhance investment and commercial certainty for proponents and to provide a more expeditious connection process); and • Increased obligations related to administration, engagement and information exchange with proponents throughout the whole connection process (which is designed to enhance customer service).
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	We have forecast this step change on the following basis: • We had a 20 per cent annual increase in committed embedded generation projects in 2013 and 2014. On this basis, we have assumed a compounding 10 per cent annual increase in embedded generation volumes; • By 2020, we project that the annual enquiry volume numbers to be: – 8 x Chapter 5 type connection projects, with a commitment of approximately 170 hours each; and – 137 x Chapter 5A type connection projects, with a commitment of approximately 17 hours each. • We expect that the Rule changes will require a doubling of effort in facilitating connections; • We expect that the Power of Choice rule change will increase the volume of embedded generation enquiries by 20 per cent per annum; • For Chapter 5 type connection projects, quantified hours are: 1,360 x 2 x 120% = 3,264 hours annually • For Chapter 5A type connection projects, quantified hours are: 2,330 x 2 x 120% = 5,590 hours annually • A typical FTE involves 1,420 working hours per annum; • Our FTE requirement is (3,264 + 5,590) / 1,420 = 6 FTEs; • We currently have two existing FTEs. We therefore require four additional new FTEs; • One FTE cost $174,664 (including on-costs); • Our additional FTE cost is 4 x $174,664 = $698,656.

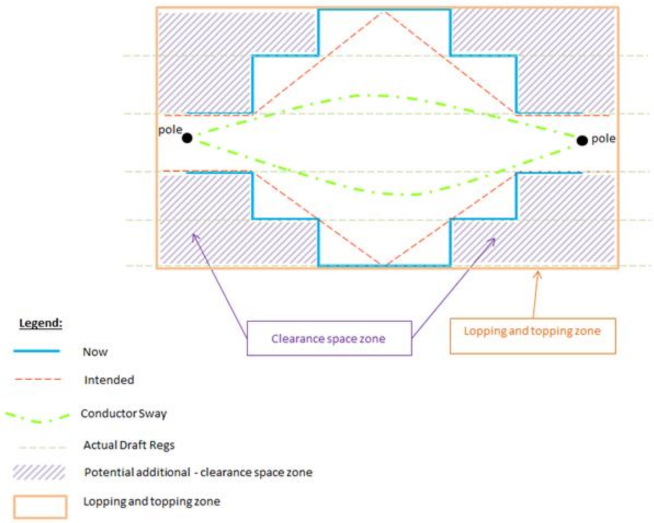
Name	2. Regulatory Information Notice reporting					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	-	0.4	0.4	0.4	0.4	1.6
Description	The AER has a clear expectation that our RIN reports will be based on actual rather than estimated data. Meeting this requirement will require us to make significant changes to our IT systems and business processes to both capture and process additional data. In addition, new and modified work practices will be required. We will incur additional costs in supporting new and modified IT systems.					
Timing of when step change will commence	The step change will commence from 2017.					
Recurrent / on-going or one-off	Meeting RIN reporting requirements will require ongoing costs over the 2017 to 2020 regulatory period.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	(a) This Opex step change is required to meet the AERs RIN Reporting Requirements.					

Name	2. Regulatory Information Notice reporting
If driver (a) above, in the current period were: (a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	Not applicable
Explain / justify why required and why not covered in rest of Opex forecast	Additional costs will be incurred from 2017 onwards to meet the AER's requirements for actual data.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The Capital and Operating Costs for the RIN Reporting Project are outlined in the document 'PJ 22 Project Justification – RIN Reporting'. The process for calculating the IT Opex impact of the implementation of the new system is as follows: • Hardware maintenance and support - $0.062 per annum based on 20 per cent of the original hardware purchase price of $0.310 million; and • Software Maintenance – $0.352 million per annum based on 22 per cent of original software purchase price of $1.6 million. The Standard Control Services IT Opex step change is $0.393 million per annum from 2017 onwards when adjusted for Standard Control Services / Alternative Control Services allocations.

Name	3a. Energy Safe Victoria safety obligations					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	0.2	0.2	0.2	0.2	0.2	1.0
Description	Costs of this step change relate to the Energy Safe Victoria proposal to implement a more rigorous audit program. Historically, Energy Safe Victoria has completed four Electricity Safety Management Scheme (ESMS) audits, and one combined Bushfire Mitigation (BFM), Electric Line Clearance (ELC) audit each year. Our involvement is about 60 days. These audits were viewed by Energy Safe Victoria as becoming a drive in the country, and as such need to become more professional. In addition to formalising these audits, Energy Safe Victoria planned to complete a number of work practice audits for us each year. Energy Safe Victoria has adopted a more scientific basis for these audit programs using a statistical basis to determine sample size, supported by more detailed audit plans, and a rigorous audit program. Historically, this audit program has involved two of our staff for about 20 days for each of the two ESMS audits and two of our staff for 10 days for the combined BFM/ELC audit. The proposed changes will increase our involvement as follows: • ESMS audits: 2 staff for 60 days; • BFM audits: 2 staff for 60 days; • ELC audits: 1 staff for 30 days; and • Work practices audits: 2 staff for 10 days. This represents an increase of about 260 days, equivalent of about 1.5 additional persons full time, based on a utilisation rate of about 75 per cent.					
Timing of when step change will commence	The proposed approach was trialled by Energy Safe Victoria in 2014, and a lead auditor was appointed with the view of rolling out the proposed program in 2015.					
Recurrent / on-going or one-off	These costs are on-going, as they relate to a change in approach adopted by Energy Safe Victoria, and signalled by Energy Safe Victoria's "new" Executive Manager Electricity Infrastructure Safety.					
Driver:	The step change relates to a proposed change in the regulatory stance adopted by Energy Safe Victoria that will apply to us from 2015.					

Name	3a. Energy Safe Victoria safety obligations
a) External - regulatory change; safety change; or stakeholder driven; or b) Internal - Capex / Opex trade-off; or effortless customer experience	We expect that the proposed changes will: • Increase the involvement of our staff in providing preparatory information to Energy Safe Victoria for the audits, making arrangements and staff available for the audit, reviewing audit findings, managing post audit reviews, and actions arising to close out; • Increase the involvement of our service providers' staff in providing preparatory information for the audits, making arrangements and staff available for the audit, and completing the actions arising to close out; and • Employ our resources, vehicles, special equipment, conference and computing facilities. This is in addition to all of the other, current, Energy Safe Victoria obligations.
If driver (a) above, in the current period were: a) Any relevant variations or exemptions granted; or b) Compliance audits undertaken?	Not applicable.
Explain / justify why required and why not covered in rest of Opex forecast	This step change relates to the costs of meeting Energy Safe Victoria's "new" approach to audits that was only introduced by Energy Safe Victoria in late 2014. Accordingly, these costs are not included in our 2014 base year, nor in any of the other elements of our base-step-trend Opex forecast.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	We have based our forecast on what we understand Energy Safe Victoria's proposal to be, informed by former Energy Safe Victoria staff that we now employ, who helped craft the proposed approach.

Name	3b. Energy Safe Victoria rule change					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	1.7	1.7	1.7	1.7	1.7	8.7
Description	Costs of this step change relate to complying with the proposed Electricity Safety (Electric Line Clearance) Regulations 2015, which would incorporate the Code of practice for Electric Line Clearance in Victoria. We note that, at the time of preparing this Regulatory Proposal, Energy Safe Victoria (ESV) was still consulting on, and finalising, the detail of the proposed Regulations. We made submissions to ESV seeking amendments to the exposure draft of the Electricity Safety (Electric Line Clearance) Regulations 2015. We expect that the final form of the Regulations will be settled before 21 May 2015 but after 30 April 2015 when we submit our Regulatory Proposal. We have examined three scenarios: • Scenario 1 – our preferred position for minimal changes to the existing Regulations; • Scenario 2 – modified Regulations but less onerous than the exposure draft of Regulations; and • Scenario 3 – Exposure draft (or some variant) of the exposure draft Regulations adopted. Our preferred position remains Scenario 1. This would involve minimal impact on our vegetation management costs and therefore would entail minimal price changes for customers. In recognition of the ESV's consultations, we have based our forecasts on Scenario 2, which would involve a step change of about $8.7 million over the forthcoming regulatory period. However, this assumes that ESV will make significant changes to the exposure draft in finalising the Regulations. If this does not occur, and the ESV implements Scenario 3, then we reserve the right to increase this step change in a Revised Regulatory Proposal that we will submit to the AER after it has made its Draft Distribution Determination. This is because we estimate that Scenario 3 would involve our vegetation management costs increasing by more than $111 million over the forthcoming regulatory period, mainly as a result of: • Increasing the amount of information, and degree of detail, provided to customers on proposed vegetation clearing activities; • Changes to the minimum clearance space with the removal of the allowance for less vegetation cutting near the pole. This will increase the amount of vegetation that needs to be removed near the pole (and add to costs), as illustrated by the shaded areas near the pole in the diagram below; and					

Name	3b. Energy Safe Victoria rule change
	• Banning lopping and topping will mean that all of the vegetation in the span, including that near the pole, cannot be pruned using lopping and topping techniques (and add to costs). This is illustrated by the shaded area between the poles. 
Timing of when step change will commence	The proposed Regulations will apply from 21 May, 2015 and replace the Electricity Safety (Electric Line Clearance) Regulations 2010, which were originally planned to expire on 29 June 2015. The proposed Regulations include a 12-month transitional period.
Recurrent / on-going or one-off	These costs are on-going, as they relate to a new regulatory obligation that will apply in Victoria from 21 May 2015.
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	The step change relates to a regulatory change that would apply to us from 2015. Although they have not been finalised at the time of submitting our Regulatory Proposal, we expect that the proposed new Regulations and associated Code will introduce the following changes: • Amended method of specifying minimum clearance spaces – this will establish a linear relationship between span distance and required clearance distance between trees and electric lines. Required distances will be represented on linear graphs rather than in tables; • Provision of alternative compliance mechanisms and exceptions to minimum clearance spaces – this will allow responsible persons to propose alternative engineering solutions to reduce clearance distances around electric lines while maintaining safety. It will allow certain small and structural tree branches to remain within the specified minimum clearance distance in low bushfire risk areas in specific conditions; • Expanded definition of insulated cable – this has redefined insulated cables to include a broader range of electric line insulations and coverings; • Adoption of the Australian Standard for the pruning of amenity trees – this incorporates a requirement for responsible persons to cut trees in accordance with the Australian Standard AS 4373-2007, Pruning of Amenity Trees; and • Increased notification, consultation and dispute resolution – this will require us to write to relevant persons notifying them of our consultation process, dispute resolution process and the intended pruning or tree removal and to provide more detailed information about our works. This will be in addition to the current optional requirement to publish notices in a newspaper generally circulating in the locality (current Regulations allow for notices to be in writing OR by publication in a newspaper…, the proposed change is for notices to be in writing AND by publication in a newspaper,….). We currently provide information about our consultation and dispute resolution provisions in our electric line clearance plans, available on the our website. This should be sufficient. We will also need to give advice to councils with respect to clearance distances in limited circumstances and also to provide guidance on working safely near electric lines when asked.
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or**	Not applicable.

Name	3b. Energy Safe Victoria rule change
(b) Compliance audits undertaken?	
Explain / justify why required and why not covered in rest of Opex forecast	This step change relates to costs of complying with new regulatory obligations that will only be introduced in 2015. Accordingly, these costs are not included in our 2014 base year, nor in any other of the elements of our base-step-trend Opex forecast.

Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	As noted above, we have based our forecast on what we refer to as Scenario 2, being a modified version of the regulations that is less onerous than exposure draft on which the ESV consulted in late 2014 and early 2015.
	Our forecast of $8.7 million over the forthcoming regulatory period is based on the following:
	• Compliance with AS4373:
	  ○ No requirement for Certificate three arborists for inspections. Instead, adopt AS4373 principles and recognise that current qualifications, or a qualification specified by ESV, is equivalent to Certificate three arborist;
	  ○ Continue to allow current work practices for tree climbing, including the use of spurs and spikes;
	  ○ Tree lopping and topping can be used in order to meet code clearance requirements but require one additional FTE to manage Local Council, community and ESV engagement about impacts at a cost of $160,000 per annum or $800,000 over the regulatory period;
	  ○ Restrict the use of mechanical tree cutting to certain applications and tree types. This would halve the benefit to us of this practice and would have a net cost of $1.25 million over the regulatory period.
	• Information provided to customers:
	  ○ Greater need for consultation with customers and Local Councils, including a requirement to notify more property owners, including neighbours that may be affected by tree cutting activity. We expect that this will double the time taken and result in twice as many notices being posted in letter boxes. This would result in a cost increase of $5 million; and
	  ○ Contact details of person carrying out the cutting will be addressed by the Vegetation Inspection Company, rather than the individuals undertaking the work;
	  ○ Provide one general notice on our website and in a statewide newspaper each week about vegetation management program at a cost of $800,000 over the regulatory period.
	• Council assistance – provide increased assistance to Local Councils in relation to their vegetation management. This would require one additional FTE at a cost of $160,000 per annum or $800,000 over the regulatory period; and
	• Minimum clearance space – assume no change in the current practices.

Name	4a. Effortless Customer Experience Program					
Amount ($M, Real 2015) - numbers may not add due to rounding	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Total Amount	1.6	1.5	1.0	1.0	1.0	6.0
Description	The Effortless Customer Experience (ECE) program is a company-wide transformation program that focuses on delivering an effortless experience to our customers during all customer transactions. During 2016-2020, we are proposing to deliver systems, update business processes, improve customer data management and roll-out customer service training so that we can provide more accurate information to our customers and keep them better informed on the status of our network during outages. There are two significant system implementations planned as part of the ECE Program: • Customer Relationship Management (CRM) System – to enable us to meet a range of customer expectations, regulatory and operational requirements; and • Customer Self Service portal – to enable customers to access a range of services such as requesting a new connection, making a claim following a fault, receiving advice and updates on planned and unplanned outages, lodging a complaint against, booking a special read and requesting a meter test. This also includes the roll-out of an integrated voice response system to better manage customers' calls and direct customers to the most suitable team to better respond and manage customer queries.					
Timing of when step change will commence	The ECE program commenced in 2014, although the planning and design work for the required major system implementations are not due to commence until 1 January 2016. The major business change activities are					

Name	4a. Effortless Customer Experience Program
	being scheduled in parallel to the Information and Communications Technology (ICT) projects in 2016 and 2017. The new CRM will be implemented in 2016 and the increased ICT opex will be incurred from 2017 onwards.
Recurrent / on-going or one-off	There is a recurring resource cost for three FTEs (one Project Coordinator and two Subject Matter Experts for the CRM and Self-Service Portal). All other business costs are one-off project costs. In addition, there will be an ongoing cost required for the continuing support and maintenance of the new/upgraded CRM ICT system.
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	(a) External - Regulatory change. We will be required to meet new regulatory requirements to: • Manage contractual arrangements with customers and record their provision of explicit informed consent to contractual arrangements; and • Capture and report on customer transactions to meet RIN reporting requirements. (b) Internal – Effortless customer experience program: • Improve consumer and stakeholder engagement; • Provide information related to the state of consumers supply and register for supply related notifications by nominated channel and track the progress of outage restorations (this will require improvements to information from field activities to ensure adequate information is available for the customer). Advise customer of issues relating to their supply – e.g. inverter tripped; and • Improve stakeholder engagement - Implementation of a more structured consultation process with community groups in our network area; alignment of communications messaging to stakeholders such as Retailers and Local Councils with our vision and corporate roadmap. (c) Internal – Service improvements and operational efficiencies to counter escalating costs associated with the increasing volume of customer interactions: • Process efficiencies (reduced customer call and administrative costs, faster service turnaround) to reduce the number of complaints; • Refine and develop policies and procedures within our Customer Resolutions team to ensure best practice complaints handling and management; and • Implement online claims and complaints lodgement process and provide status monitoring for customers.
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	N/A
Explain / justify why required and why not covered in rest of Opex forecast	• The ECE initiative is a new focus are and is based on the feedback provided by our customers as part of our stakeholder engagement initiative on how they would like to interact with us. • We have an existing SAP CRM system, but with the increased usage/scope and additional capability, there will be a requirement for increased application support.

Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	• The program office costs associated with this Project comprise:
	  ○ One Program Manager – program management;
	  ○ One Program Coordinator – provision of management activities for major system changes and ongoing systems improvements and enhancements;
	  ○ Two Subject Matter Experts - to provide CRM expertise and Self-Service Portal expertise;
	  ○ One senior Business Manager - business liaison and Culture Change Manager; and
	  ○ Three Project Stream Managers - to deliver Knowledge Management system and processes, delivery of business processes for CRM and Self-Service Portal.
	• The business backfill costs associated with this Project comprise:
	  ○ One Customer and Market Operations Resource – backfill for CMO resource providing CMO business analysis and process redesign;
	  ○ One Service Delivery Resource – backfill for resource from Service Delivery providing Service delivery business analysis and process redesign; and
	  ○ Six additional FTE for Field Based Service Providers – additional customer resolutions agents in service providers to roll out improved customer service standards.

Name	4a. Effortless Customer Experience Program
	• The costs and benefits associated with the ICT projects are included in "UE ICT Capital Program 2016-2020". In addition to the ICT projects, a business change program will involve a number of project managers and resources taken from the business and also incorporate a company-wide cultural change management program to ensure that we implement a customer focused operating model; • Applications support costs are also required for a new and/or upgraded Customer Relationship Management system (CRM). The description of the project to implement CRM capability is provided in 'PJ 03 CRM Solution.' The forecast cost increase for IT application support is based on the assessment that our current applications support service provider will require two additional full time resources, during business hours, to support the new system; and • Based on the rates defined in the contract between us and the application support service provider, the cost of two additional FTEs is $462,000 (which when adjusted for Standard Control Services/Alternative Control Services allocations is $439,000).

Name	4b. Stakeholder engagement					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	0.3	0.3	0.3	0.3	0.3	1.3
Description	Costs of employing two specialists to undertake on-going stakeholder engagement in the forthcoming regulatory period. One role would be a relationship manager for the 15 local councils in our service area. The second role would be focused on engaging stakeholders about future capital projects.					
Timing of when step change will commence	This step change would take effect from the start of the forthcoming regulatory period.					
Recurrent / on-going or one-off	These costs are on-going, as they relate to our need to increase and improve our engagement with stakeholders throughout the forthcoming regulatory period.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	The 2012 changes to the Rules and the AER's Consumer Engagement Guidelines introduced new regulatory requirements for us to engage our customers and other stakeholders, not only to inform our Regulatory Proposal but throughout the forthcoming regulatory period. We do not currently have the required resourcing to do this. Our 15 local councils provide an important opportunity for us to create partnerships that enhance engagement outcomes – providing services side-by-side in many cases, in a non-competitive environment. A strategic approach to engagement with our local councils would enhance our ability to engage with end-use customers far better than we could do on our own. Local council partnerships will also help to identify avenues to engage with special interest community groups across our network. A significant number of projects are planned for the forthcoming regulatory period that will require effective consultation to meet customer, community and media expectations and to assist with the delivery of successful outcomes. The two roles will therefore: • Create partnerships with our 15 local councils and work closely with relevant community groups; • Develop, manage and implement project marketing plans; • Undertake community consultation activities associated with capital projects; and • Facilitate demand management programs from community engagement through to customer fulfilment.					
If driver (a) above, in the current period were: (a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	Not applicable.					
Explain / justify why required and why not covered in rest of Opex forecast	We are not currently resourced to effectively meet stakeholder engagement requirements throughout the forthcoming regulatory period. Our 2014 base year Opex does not include provision for within period stakeholder engagement resources. In response to changing regulatory requirements relating to stakeholder engagement that have emerged within the current regulatory period, we have focussed on enhancing our Customer Consultative Committee and incremental improvements on communication on our capital projects					

Name	4b. Stakeholder engagement
	and new initiative, such as our summer energy demand trial. In order to deliver more comprehensive stakeholder engagement, additional specialist resources are required.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	We have based this step change on two full-time resources being employed from the start of the forthcoming regulatory period on an on-going basis.

Name	4c. Council trees					
Amount ($M, Real 2015) - numbers may not add due to rounding	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
	-	1.0	1.0	1.0	-	3.0
Description	Costs of a dedicated service that would be available to all local councils to assist them to clear their existing backlog of tree cutting. This would be undertaken for a limited period of three years until the local councils' backlog is cleared.					
Timing of when step change will commence	This step change would begin from the start of the forthcoming regulatory period, 1 January 2017.					
Recurrent / on-going or one-off	This would be a three year program that would be targeted at clearing local councils' existing backlog of trees that require cutting.					
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	We are proposing this step change to address a specific need that has been identified by local councils. The inclusion of this step change in our Opex forecast has local councils' explicit support. Local councils support this initiative because they consider that: • They are not currently sufficiently well supported in undertaking their tree cutting activity; • The costs of local councils addressing this backlog alone is prohibitive; • Without a specific program of work such as this the backlog will continue to grow; • Three years of support is sufficient to address the current backlog; • We are best placed to clear the backlog because it will involve extensive live line work and suppression of network; • The program will deliver material public safety benefits; and • We cannot unilaterally undertake the program without local councils' support – for this reason the program would be available to local councils at their own volition.					
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	Not applicable.					
Explain / justify why required and why not covered in rest of Opex forecast	The extra tree cutting is not included in the 2014 base year Opex. It has been specifically included as a step change at the request of local councils to address their existing backlog program. It will continue to be the local councils' responsibility to undertake this work. We would only undertake this work if this step change is approved and local councils ask us to do specific work – we will not be taking on local councils' responsibility to undertake this work.					
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The step change is based on $1 million per annum for three years. This amount has been determined in cooperation with local councils having regard for the level of work that is required to address their current backlog.					

Name	5. Customer charter					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	-	0.7	-	-	-	0.7
Description	Cost of preparing and distributing a new Customer Charter.					
Timing of when step change will commence	We must prepare and provide a new Customer Charter to our customers in 2017. We must do this every five years. The last time that we did this was in 2012. This cost is therefore not in our 2014 base year Opex.					
Recurrent / on-going or one-off	This cost is recurrent, but occurs only every five years.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	This step change is driven by clause 9.1.2(b) of the Electricity Distribution Code that requires that: "A distributor must promptly provide a Customer Charter to each customer and the Commission: (a) …….. (b) at least once every 5 years, and to each customer at the time the customer is connected at the customer's supply address." Given that the last time we provided our Customer Charter to each customer and the Essential Services Commission was in 2012, we must address this requirement in 2017.					
If driver (a) above, in the current period were: (a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	Not applicable.					
Explain / justify why required and why not covered in rest of Opex forecast	This cost is not included in our 2014 base year Opex because it only arises every five years when we need to prepare a new Customer Charter and provide it to all of our customers. Accordingly, the cost is not included in our 2014 base year, nor is it included in any other of the elements of our base-step-trend Opex forecast.					
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The cost of undertaking this exercise includes fully reviewing our Customer Charter to take into account the AER's decision on this Regulatory Proposal, and any other changes since the current version was produced. The cost also includes producing the Customer Charter and mailing it out to all of our end-use customers. The forecast has been prepared based on 650,000 customers and an estimated cost of $1.05 per document, based on: • Redesign of $0.05; • Printing of charter, including letter, envelope and insertions of $0.35 • Distribution costs of $0.65.					

Name	6. Regulatory submission cost					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	-	-	-	1.5	0.8	2.3
Description	Costs of preparing our Regulatory Proposal and Revised Regulatory Proposal, responding to the AER's reset regulatory information notice and engaging with AER and other stakeholders for regulatory period commencing 1 January 2021.					
Timing of when step change will commence	In 2019, we will engage with our stakeholders about our forthcoming regulatory period, prepare our Regulatory Proposal and respond to the AER's reset regulatory information notice. In 2020, we will prepare our Revised Regulatory Proposal before the AER's distribution determination applies in 2021.					
Recurrent / on-going or one-off	These costs are recurrent, but they only occur every five years.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or	These costs are driven by external regulatory obligations under chapter 6 of the Rules and the AER's reset regulatory information notice that we expect it to issue. We have an obligation to submit a Regulatory Proposal, a response to the AER's reset regulatory information notice and a Revised Regulatory Proposal					

Name	6. Regulatory submission cost
(b) Internal - Capex / Opex trade-off; or effortless customer experience	for each new regulatory period. We also have obligations to engage with our stakeholders under Chapter 6 of the Rules and the AER's Consumer Engagement Guidelines.
If driver (a) above, in the current period were: (a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	Not applicable
Explain / justify why required and why not covered in rest of Opex forecast	Although we incurred regulatory submission costs in 2014, we explicitly removed them from our 2014 base year as they are not recurrent costs that will be incurred in every year of the forthcoming regulatory period. Consequently, our base year costs do not include regulatory submission costs. We therefore need to include the costs associated with this step change in 2019 and 2020, when we will prepare our regulatory submission to the AER for the regulatory period commencing 2021.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	The forecast step change for 2019 and 2020 is based on the actual cost in 2014 and the forecast cost for 2015. These are external cost only and include: • Costs associated with preparing forecasts; • Costs associated with reviewing the adequacy of asset management plans; • Costs associated with writing of the submission documents; • Costs associated with cost of capital submissions; • Other expert and strategic advice; and • Legal costs in complying with the submission. The step change forecast excludes: • Internal labour costs; and • An allocation of overheads.

Name	7a. Neutral testing					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	-	0.1	0.1	0.1	0.1	0.4
Description	Costs of (a) staff utilising our ICT analytics and supporting capabilities, and our AMI power quality data, to identify neutral integrity issues without the need to rely on an on-site test and (b) 300 site visits per annum to investigate detected issues, in order to meet our obligation under the Electricity Safety (Network Assets) Regulations 1999 to inspect earthing systems every 10 years (c) Neutral integrity testing is required in 2016 for the services at 17,660 sites where meters have not been replaced as part of the meter rollout and hence have not undergone a neutral integrity test in line with safety requirements. A submission has been made to the ESV requesting an exception for these 17,660 customers. There are no costs included in this submission to fund these inspections should the ESV rejects this request.					
Timing of when step change will commence	This step change will commence a rolling annual program of neutral integrity testing to meet our obligation to inspect earthing systems every 10 years. Proof of concept development will start in 2015, and will be finalised in 2016. Implementation and rollout will occur in 2017.					
Recurrent / on-going or one-off	These costs are on-going, as they relate to complying with a regulatory obligation under regulation 27(2) of the Electricity Safety (Network Assets) Regulations 1999.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	Regulation 27(2) of the Electricity Safety (Network Assets) Regulations 1999 provides that "Earthing systems, except common multiple earthed neutral earthing systems, and electrical protection equipment, except fuses, must be inspected and tested at least every 10 years for compliance with regulation 23". Regulation 23 details requirements in relation to earthing and electrical protection. In recent years, we have met our obligations under Regulation 27(2) as part of the rollout of our advanced metering infrastructure program. This has involved undertaking a Neutral Supply Test on-site at each property once every ten years and whenever there is a change to a physical meter configuration. We undertake around 65,000 customer site visits annually.					

Name	7a. Neutral testing
	We are proposing ceasing this practice for the majority of cases and instead implementing an intelligent software solution to detect neutral integrity issues as they occur. This will avoid the need for routine site visits. To achieve this we will invest in two forms of operational analytics through our capital program. The first will involve traditional Operational Data Warehouse and reporting structures. The second will involve an 'Information Hub' that enables the identification, prototyping and support for new analytics requirements. We will use our ICT analytics and supporting capabilities to leverage our AMI power quality data to identify neutral integrity issues. We will need to incur the following Opex to do this: • One additional office-based FTE and two additional field-based FTEs; • Approximately 300 individual site visits per annum to investigate detected issues; and • We will be awaiting the outcome of the ESV exception application. The testing regime will be required to continue for the approximately 17660 sites were access has not been made available to replace the meter as part of the advanced metering infrastructure program should the application be unsuccessful.
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	Not applicable.
Explain / justify why required and why not covered in rest of Opex forecast	The costs associated with neutral integrity testing are not included in the 2014 base year because the testing that was undertaken in 2014 was undertaken as part of the advanced metering infrastructure program. We commenced our inspections in 2009 as part of our advanced metering infrastructure rollout. We will need to undertake dedicated neutral integrity testing from 2019 at premises that were last inspected in 2009 in order to comply with our 10 year inspection obligation. All premises needs however to be inspected before end 2024, as all the meters were installed before December 2014. The advanced metering infrastructure program has not replaced 17,660 meter due to access issues. These sites are still required to undergo a neutral integrity test as no tests have been undertaken in conjunction with meter replacements. A submission has been made to the ESV requesting an exception for these 17,660 customers. There are no costs included in this submission to fund these inspections should the ESV reject this request. Even though there will be minimal need for neutral integrity testing between 2016 and 2018 because majority of our neutrals will have been tested within the last 10 years (in compliance with Regulation 27(2) of the Electricity Safety (Network Assets) Regulations 1999) in conjunction with the advanced metering infrastructure rollout program, if we were to do a physical neutral integrity test, the program of work will need to commence in 2016 to cover the entire network before 2024. If the activity associated with these costs is not undertaken then we will not comply with our regulatory obligation to inspect our earthing systems every 10 years. There are two options to fulfil these obligations: • Visit and test the 650 000 premise every 10 years (with associated works management costs) • Perform these inspections remotely with analytics and as per Electricity Safe Victoria (ESV) recommendations Option 2 is by far the least cost method and result in accurate daily "inspections" compared to once every 10 years. This will also allow the ability of real time reporting of a safety issue on the premise as it occurs.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	We have based our forecast step change on: • One additional office-based FTE and two additional field-based FTEs at a total cost of $450,000 per annum commencing in 2017. These staff will be required to perform and confirm the outputs from the Analysis Dashboards and to perform preliminary field investigation and root cause analysis work; and • Analytics will detect neutral problems as they occur and they will need to get fixed on the same day. These would have been fixed on the spot while the smart meters were installed, with no callout applicable. Approximately 300 individual site visits per annum will be required by fault trucks and inspectors to investigate and correct detected issues at a cost of $400 per site visit and a total cost of $120,000 per annum.

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Name	7b. Network Planning and Analytics - ICT Capital Program					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	-	-	0.8	1.2	2.1	4.1
Description	Applications support costs for a new Network Planning and Analytics solutions that will enable us to maintain the quality, reliability and security of the supply of Standard Control Services.					
Timing of when step change will commence	The new solution will be implemented in 2018 and the increased Opex will be incurred from 2019 onwards.					
Recurrent / on-going or one-off	This is an ongoing cost required for the continuing support and maintenance of a new system.					
Driver: (a) External - regulatory change; safety change; or stakeholder driven; or (b) Internal - Capex / Opex trade-off; or effortless customer experience	(b) Internal • Network Planning and Analytics will enable us to maintain the quality, reliability and security of the supply of Standard Control Services by performing analysis of network operational data from AMI meters and other data monitoring and data collection devices to inform network maintenance and capital investment programs; and • Network Planning and Analytics will also avoid increased network Opex by removing the need for manual neutral integrity testing for all connections points on our network.					
If driver (a) above, in the current period were: (a) Any relevant variations or exemptions granted; or (b) Compliance audits undertaken?	N/A					
Explain / justify why required and why not covered in rest of Opex forecast	• Network Planning and Analytics solutions are new ICT capabilities for us. The solution, as planned, will require new hardware and vendor-provided software.					
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	• The Capital and Operating Costs for the Network Planning and Analytics Project are outlined in the document 'PJ12 Project Justification – Network Analytics'. • The process for calculating the Opex impact of the new system is as follows: o Hardware Maintenance and support (based on 20 per cent of the original hardware purchase price per annum) o Software Maintenance – (based on 22 per cent of original software purchase price per annum) o Application support – (based on the cost of a support team of two FTEs at the rates defined in the existing contract between us and the application support service provider).					

Name	8. Guideline 11 Energy and Water Ombudsman (EWOV) Direction					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	0.9	0.9	0.9	0.9	0.9	4.5
Description	The ESCV's Electricity Industry Guideline No. 11 Voltage Variation Compensation outlines the requirements for us to make compensation payments to customers following a voltage variation. In previous years, we have interpreted that payments associated with acts outside our control (e.g. weather, animal, bird) were not eligible. Recent position statements from EWOV have however clarified that we are required to make compensation payments for all voltage variations, regardless of the cause of the variation. This policy clarification has resulted in an increased forecast of claims costs of $900,000 per annum compared to our 2014 costs.					
Timing of when step change will commence	This change will take effect from 1 January 2016.					
Recurrent / on-going or one-off	This step change is on-going.					

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Name	8. Guideline 11 Energy and Water Ombudsman (EWOV) Direction
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	We are required to comply with Guideline 11 and the Electricity Distribution Code. In the past, we have not made payments for claims greater than $1,000 per claim caused by weather, animal or bird. This has resulted in an increased number of EWOV complaints and non-compliance with Guideline 11. Guideline 11 does not call out cause or exceptions. Therefore, if a customer substantiates a claim with a statement from a registered electrical contractor that damage was sustained due to unauthorised voltage variation, then we are required to pay the claim. Making payments for these claims in the future should reduce complaints to EWOV and is consistent with our commitment to delivering an effortless customer experience.
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	N/A
Explain / justify why required and why not covered in rest of Opex forecast	New claims costs not previously paid under our claims and payment processes.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	A new process has been implemented whereby if a confirmed high voltage injection (HVI) occurs due to our equipment failing, we will directly engage a registered electrical contractor/Assessor to automatically repair and/or replace any essential items damaged. On average we receive 20 claims per month related to weather/animal/bird – the associated average cost is around $4,500. This equates to $1.08 million per annum. By accepting and compensating these claims going forward, we will reduce our complaints and EWOV costs by approximately $0.2 million per annum. This result in an additional $0.9 million per annum being required for claims from 2016 to comply with Guideline 11.

Name	9. ICT Security					
Amount ($M, Real 2015) - numbers may not add due to rounding	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
	0.7	0.8	0.8	0.8	0.8	4.0
Description	A step change in ICT Security Opex arising from the ICT capital project “Security Program” (refer to the document ‘Project Justification - Security Program’) and a significant increase in spending on ICT Security resources and services to counter external threats and risk to us. The purpose of the Security Program is to manage and maintain the operational risks related to information security by maintaining the baseline security environment across the logical, physical and process environments in line with the increased level and sophistication of targeted cyber security threats. The program will protect customers from major outages, theft of personal data and other adverse outcomes from potential security breaches. Further details are contained in the document ‘New Strategies for the Future UE Network’.					
Timing of when step change will commence	We are increasing focus on information security by developing an Information Security Strategy. This strategy will have five key priorities: • Aligning our security strategy to our business strategic objectives • Creating a secure culture where everyone is responsible for protecting our information and assets • Delivering business and technology solutions that are secure • Building a security risk and governance model to drive continuous improvements in our security maturity level • Uplifting security operations capability to better protect, detect and respond to security threats and incidents. **Security Program**: The increase will progressively occur across the 2016 to 2020 period as the individual projects in the ICT security program are deployed. Projects include:					

Name	9. ICT Security
	• Secure Network Design; • Remote and External Connectivity; • Secure Build and Host Hardening; • Malicious Software Prevention; • Vulnerability Management; • Security Testing; • Physical Security; • Personnel / Human Resource Security; and • Security Incident Management. **Security Services:** A new IT Security Services contract commencing in 2015 will apply throughout the forthcoming regulatory period and beyond. The service provider will: • Work with customer and other Service Providers to maintain and manage an information security management system consisting of a coherent set of policies, processes and systems to manage risks to customer's information assets ensuring an acceptable level of information security risk; • Provide management and governance over security related services, processes, activities, projects and systems applied and managed by other Service Providers; • Provide security consulting services to projects; • Provide security testing services; • Provide security awareness services; and • Work with customer and other service providers to manage and maintain operational effectiveness of all security controls and technology across the environment
Recurrent / on-going or one-off	Provision of security services and support for new security systems will continue throughout the period.
Driver: **(a) External - regulatory change; safety change; or stakeholder driven; or** **(b) Internal - Capex / Opex trade-off; or effortless customer experience**	(a) External - This is an externally driven change in that the risk associated with security breaches is largely external to us and increasing globally. We have already identified and recorded ICT Security as a Major Risk in its corporate risk register. The driver for this step change is to mitigate the corporate risk and reduce it to a more acceptable level (refer to Project Justification).
If driver (a) above, in the current period were: **(a) Any relevant variations or exemptions granted; or** **(b) Compliance audits undertaken?**	N/a
Explain / justify why required and why not covered in rest of Opex forecast.	The ICT Opex step change relating to security is required based on: • Increased costs arising from the capital project "Security Program". Refer to Project Justification for Economic Evaluation; and • Increased spending on external Security Services under a new Security Services Contract. The Security Program and increased Opex costs are shared between United Energy and MultiNet Gas, only the United Energy costs are presented here.
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken.	The Project Justification document 'PJ23 Security Program' provides the rationale behind the increase in ICT Opex relating to the Capital program. As with other Capital Projects, the ICT Opex step change relates to hardware and software support and maintenance and on-going application support. This has been calculated as described under Regulatory Projects above. Costs for the ongoing security services are based on formal quotations from suppliers of security services as a result of a request for proposal process carried out by us.

Name	10. Insurance premiums					
Amount ($M, Real 2015) - numbers may not add due to rounding	2016	2017	2018	2019	2020	Total
	0.3	0.4	0.5	0.6	0.7	2.3
Description	Increase in costs to procure insurance for: • Public liability and professional indemnity insurance; • Property insurance; • Directors and officers liability insurance; • Employment liability insurance; • Motor vehicle insurance; • Crime insurance; and • Travel insurance.					
Timing of when step change will commence	1 January 2016					
Recurrent / on-going or one-off	Recurrent					
Driver: c) External - regulatory change; safety change; or stakeholder driven; or d) Internal - Capex / Opex trade-off; or effortless customer experience	External – general market conditions for insurance are expected to change and result in increased insurance rates across all classes of insurance.					
If driver (a) above, in the current period were: c) Any relevant variations or exemptions granted; or d) Compliance audits undertaken?	N/A					
Explain / justify why required and why not covered in rest of Opex forecast	The costs for the above insurance are not reflected in any other Opex forecast item.					
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	Advice from Marsh, a leading global insurance broker, was obtained to quantify the premium forecasts. Refer to Marsh report titled “Estimation of Insurance Premiums 2015-2020” that has been provided as an attachment to the Regulatory Proposal. Premiums forecasts are based on our current insurance program, which is customary in the electricity industry. All relevant factors are considered in assessing the extent and level to which our assets and risks should be insured, including the nature and size of our operations, industry practice, insurance premiums and assessment on risk. The level and extent of cover of our insurances are considered reasonable, with all material insurance arrangements are approved by our Board on recommendation by management. The increase in insurance costs for each year is calculated as the difference between the estimated insurance costs in that year relative to the insurance costs in 2014. Refer to the “Summary” tab in the “Insurance Premium Forecasting EDPR” excel file that has been provided as an attachment to the Regulatory Proposal. Note that costs for employment liability insurance, motor vehicle insurance, crime insurance and travel insurance are shared with Multinet Gas. Only 70 per cent of the total forecasted premiums for these insurance policies are allocated to United Energy. The calculated increase in costs reflect United Energy’s share of costs for these insurance policies.					

<table>
<tr><td>Name</td><td colspan="6">11. Pole Top Structures – Step Change</td></tr>
<tr><td rowspan="2">Amount ($M, Real 2015) - numbers may not add due to rounding</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>Total</td></tr>
<tr><td>0.6</td><td>0.6</td><td>0.6</td><td>0.5</td><td>0.2</td><td>2.4</td></tr>
<tr><td>Description</td><td colspan="6">This step change requests additional Opex required for implementation of aerial camera inspection of pole top assets (an additional capability) during regular cycle pole inspection activities.</td></tr>
<tr><td>Timing of when step change will commence</td><td colspan="6">2016</td></tr>
<tr><td>Recurrent / on-going or one-off</td><td colspan="6">Ongoing</td></tr>
<tr><td>Driver:
(a) External - regulatory change; safety change; or stakeholder driven; or
(b) Internal - Capex / Opex trade-off; or effortless customer experience</td><td colspan="6">Internal - Capex / Opex trade-off</td></tr>
<tr><td>If driver (a) above, in the current period were:
(a) Any relevant variations or exemptions granted; or
(b) Compliance audits undertaken?</td><td colspan="6">N/a</td></tr>
<tr><td>Explain / justify why required and why not covered in rest of Opex forecast</td><td colspan="6">Pole Top Structure performance issues
Pole top structures performance has deteriorated to the level that places this asset class as the highest contributor to network performance or STPIS. Under the reporting template required by ESV since 2011 the following volumes of failures were reported for pole top structures. These volumes show an alarming increase in failures and in response we have assessed intervention options for the management of this asset.
Table 1: Failures Reported to ESV
<table>
<tr><th>Item class</th><th>Incident</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th></tr>
<tr><td>Asset failures resulting in asset fire (no grass/veg fire)</td><td>a) Pole and crossarm fire</td><td>6</td><td>30</td><td>76</td><td>133</td></tr>
<tr><td>Asset failure (no fire)</td><td>b) Crossarm failure (includes outage related and maintenance related)</td><td>57</td><td>84</td><td>173</td><td>103</td></tr>
<tr><td>Asset failure (no fire)</td><td>g) Dislodged Asset</td><td>0</td><td>1</td><td>10</td><td>11</td></tr>
<tr><td colspan="2">Total</td><td>63</td><td>115</td><td>260</td><td>251</td></tr>
</table>
From the Safety Performance Report on Victorian Electricity Networks 2013 published by ESV in June 2014 the following comments were documented specific to our crossarm replacement program:
"Crossarm replacement is not keeping pace with the rate of crossarm failure, seriously impacting the program's safety objectives of fewer asset failures leading to fewer fires. United Energy's crossarm condition assessment has identified fewer crossarms for replacement, which is inconsistent with the increasing failure rate."
In 2013, we initiated a Reliability Centred Maintenance (RCM) study into crossarms and pole top structures. This study recommended the introduction of aerial camera inspection of pole top structures as an enhancement to the current
A trial of aerial camera inspection was conducted over a six-month a period in 2014 and this trial demonstrated the following outcomes;</td></tr>
</table>

Name	11. Pole Top Structures – Step Change
	• Improved accuracy of the condition assessment of crossarms with the additional capability of viewing the top surface of the crossarm. The top surface of a wood crossarm is the surface with the highest exposure to external degradation factors and therefore the primary point of deterioration. • Improvement in the quality of asset inspections – the capability to make a more accurate condition assessment allows inspectors to be less conservative with their assessments. • Capability to repeat and review the assessments in office (via photographs) The introduction of aerial inspection of pole top structures will allow for the following future reductions in capital expenditure requirements for this asset class (below average yearly capital expenditure within the current price review period); • Reduction in capital expenditure requirements from 2014 levels • Forecast yearly capital expenditure for the 2016-2020 price review period below the average yearly expenditure for the 2011-15 price review period • Improvement in efficiency of expenditure by improved accuracy/ quality of inspections, i.e. identifying the correct pole top structures for replacement The improvement in the quality and accuracy of pole top structure assessments is expected to address the increasing trend of failures and return the performance of this asset class to the target of the historical five year average for failures. The capital expenditure forecast for this asset class, demonstrating the outputs above, is; 
Explain process for quantification / calculation of preferred option and nature of cost-benefit analysis undertaken	We have considered six options for the efficient management of life cycle costs and risks associated with pole top structures. These options are: 1. Targeted Reliability Improvement Scheme (in areas of poor network performance or high pollution) 2. Status quo (3/5 year inspection cycle with ground based visual inspection of pole top structures) 3. Proactive population replacement 4. Increase inspection regime to address KPIs 5. Introduce aerial camera for inspections 6. Do nothing – run to failure. Operational maintenance would be all reactive, fixing faults and defects when they occur. Capital replacement would only occur post failure. Our cost and risk assessment identifies Option 5 as the preferred approach. A run-to-failure approach (Option 6) exposes us and our customers to unacceptable risks, proactive replacement of the entire population of wood high voltage and sub-transmission cross-arms (Option 3) is not feasible from a cost perspective and the remaining options were not assessed to be the lowest lifecycle cost for the asset class. The Opex expenditure required to deliver the preferred option was obtained from a market tender process for provision of asset inspection activities (in-house managed) and is deemed to be an efficient market rate for the activities. The aerial pole top inspection program was run as a trial in 2014 for a six month period in addition to the current pole inspection program. The $2.4 million forecasts is based on the difference between an ongoing program of improved asset inspection and the costs incurred during the 2014 benchmark year for asset inspection. The difference is driven by a new scope (i.e. no longer a trial) and an increase in volumes to align with pole inspections.

6.6. Guaranteed Service Levels

We apply the jurisdictional GSLs scheme that is detailed in section 6 of the Electricity Distribution Code. It requires us to make payments to customers where we do not meet specific performance standards in relation to timeliness of attending appointments, providing supply and restoring supply in the event of outages.

The AER indicated in its Framework and Approach paper that, because the Victorian GSL scheme will continue to apply in the forthcoming regulatory period, it will not apply the GSL component of the national STPIS. We support this approach.

Our Capex and Opex forecasts for the forthcoming regulatory period are based on maintaining our reliability performance at the average of our last five years' performance, adjusted (i.e. made more onerous) for changes in the classification of some of our feeders from rural to urban. On the basis of these forecasts we anticipate a zero STPIS impact for reliability in the next regulatory period.

By extension, we are expecting that our GSL payments will remain at our historical levels. We are therefore assuming that our 2014 base year GSL payments of $1.1 million will continue throughout the forthcoming regulatory period.

Table 12 details our forecast GSL costs in the forthcoming regulatory period.

Table 12 - GSL costs ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
GSL	1.1	1.1	1.1	1.1	1.1	5.7

6.7. Demand Management Innovation Allowance

The AER indicated in its Framework and Approach paper that it intended to continue to apply the DMIS in the forthcoming regulatory period. However, given that our Standard Control Services would be regulated under a revenue cap, it would only apply Part A of the DMIS relating to the demand management innovation allowance (DMIA).

We were allowed $0.4 million per annum for the current regulatory period (i.e. $2 million in total) as an ex-ante allowance under the DMIA for the current regulatory control period. We plan to spend this full allocation by the end of this current regulatory period on the three projects:

- Doncaster Hill District Energy Services Scheme;
- Virtual Power Plant (VPP) Pilot; and
- Bulleen Demand Response (Summer Saver) Pilot.

Given the success of each of these projects, and the likely use of our full allocation of DMIA funding in the current regulatory period, we are proposing that our DMIS allowance be increased to $6.6 million for the forthcoming regulatory period. This will enable us to explore demand management opportunities and capabilities further. Our "Demand Management & DMIS Strategy & Plan" (document UE PL 2210) that is an attachment to this Regulatory Proposal explains and justifies our proposed DMIA allowance further.

Table 13 details our proposed DMIS in the forthcoming regulatory period.

Table 13 - DMIS ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
DMIS	2.4	1.3	1.1	1.1	0.8	6.6

6.8. Debt raising costs

Table 14 details our forecast debt raising costs in the forthcoming regulatory period.

Table 14 - Debt raising costs ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Debt raising costs	2.5	2.6	2.7	2.9	3.0	13.7

Our justification for our debt raising costs is detailed in our Regulatory Proposal.

7. Meeting Rules' requirements

7.1. The operating expenditure objectives

The Rules set out the objectives the proposed Opex for the forthcoming regulatory control period is required to achieve.

Clause 6.5.6(a) is:

(a) A *building block proposal* must include the total forecast operating expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *operating expenditure objectives*):

(1) meet or manage the expected demand for *Standard Control Services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *Standard Control Services*;

(3) to the extent that there is no applicable *regulatory obligation or requirement* in relation to:

(i) the quality, reliability or security of supply of *Standard Control Services*; or

(ii) the reliability or security of the *distribution system* through the supply of *Standard Control Services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *Standard Control Services*; and

(iv) maintain the reliability and security of the *distribution system* through the supply of *Standard Control Services*; and

(4) maintain the safety of the *distribution system* through the supply of *Standard Control Services*.

Standard Control Services are core network services and connection services. Our proposed Opex is required to provide these services.

Meeting and managing expected demand for Standard Control Services, as required by clause 6.5.6(a)(1), is the predominant objective of our proposed Opex. This includes operating, maintenance and other non-capital expenditure that we incur to provide our services to our customers. Our demand forecasts are explained and justified in chapter 9 of the Regulatory Proposal.

Our proposed Opex is necessary to comply with all applicable regulatory obligations or requirements associated with the provision of Standard Control Services, as required by clause 6.5.6(a)(2). These include the requirements of the Electricity Distribution Code. Clause 5.2 of this Code provides that:

> *A distributor must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

We do not have any targets published under clause 5.1. As a consequence, we must meet the targets specified under the Service Target performance Incentive Scheme and the reasonable reliability expectations of customers. Our "Customer engagement initiatives and outcomes" document explains that customers indicated a desire for their current average levels of reliability performance to be maintained in the forthcoming regulatory period.

Accordingly, our proposed Opex is required to meet or manage growth in localised maximum demand whilst maintaining average levels of reliability across the network over the current period in accordance with the Electricity Distribution Code.

7.2. Operating expenditure criteria

The Rules set out the expenditure criteria that are relevant to our Opex forecast for the forthcoming regulatory control period.

Clause 6.5.6(c) is:

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

(1) the efficient costs of achieving the *operating expenditure objectives*;

(2) the costs that a prudent operator would require to achieve the *operating expenditure objectives*; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

We have used a BST approach to forecast our Opex for the forthcoming regulatory period. This is consistent with the approach that we proposed in our Expenditure Forecasting Method that we submitted to the AER in May 2014 and the AER's preferred approach for how it would like us to prepare our Opex forecast, as detailed in its Expenditure Forecast Assessment Guideline.

A BST approach involves forecasting our Opex at an aggregate level, rather than preparing individual forecasts for each category of Opex, as detailed in the AER's Annual RIN.

The starting point for the BST approach is that the incentive properties of the AER's EBSS mean that our base year Opex reflects prudent and efficient costs. This is because the efficiency carryover mechanism under the EBSS incentivises us to minimise our Opex, while ensuring that we continue to meet our regulatory obligations and to achieve our service performance targets.

The BST approach is detailed in section 5 of this Overview Paper.

In relation to the efficiency criterion:

- The AER and Huegin's benchmarking both indicate that our historical Opex is at, or close to, the efficient frontier of DNSPs in the National Electricity Market;
- We have applied the AER's preferred BST approach to forecasting Opex, which is based on an efficient build-up of costs;
- Our 2014 Opex provides an efficient base year for our Opex forecast. We have adjusted our 2014 base year for, amongst other things, Opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period;
- Our real labour cost escalators have been determined by independent experts, BIS Shrapnel;
- Our output growth forecast has been determined based on movements in customer numbers, circuit length and ratcheted maximum demand, in accordance with the AER's preferred approach; and
- Our step changes have been forecast using a build-up of labour and material costs that are detailed in section 6.4.1 above. They reflect our contractual arrangements with our key service providers that have been determined through competitive tender processes and include incentives that align our, and our service providers', objectives.

In relation to the prudency criterion:

- We have structured our Opex forecasts to maintain the quality, reliability and security of supply of our Standard Control Services to our customers, except where there is as explicit new regulatory requirement that we have addressed through our proposed step changes; and
- We have included a range of step changes that reflect: new regulatory obligations; existing recurrent but non-annual regulatory obligations; specific customer requests or needs; changes in our external environment; and

Capex-Opex trade-offs. We have explained the need for, and timing of, these step changes in section 6.4.1 above.

7.3. Operating expenditure factors

The Rules set out the operating expenditure factors to which regard must be had in considering our Opex forecast for the forthcoming regulatory control period.

Clause 6.5.7(e) is:

(e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c), the *AER* must have regard to the following (the *operating expenditure factors*):

(1) [**Deleted**]

(2) [**Deleted**]

(3) [**Deleted**]

(4) the most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*;

(5) the actual and expected operating expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and operating expenditure;

(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8A or 6.6.2 to 6.6.4;

(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms;

(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b);

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient and prudent non-*network* alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p) or (s):

(12) any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is an operating *expenditure factor*.

In relation to subparagraph (4), the AER's November 2014 benchmarking report, discussed in section 4.3, shows that we benchmarks very favourably against other DNSPs. Moreover, we have delivered the highest utilised network in Australia according to AER benchmarks.

In relation to subparagraph (5), we have set out, in section 4, our actual Opex during the previous regulatory control period (2005-10) and actual and expected Opex in the current regulatory control period (2011-15). To accompany this information, we have presented the actual and expected Opex by reference to the allowance approved by the AER (and, for the 2005-10 regulatory control period, the ESC) and in section 5.2 explained the factors that have contributed to any variance from these allowances.

In relation to subparagraph (5A), we conducted a comprehensive program of customer engagement to identify the concerns of customers and to ensure that its proposed Opex addresses those concerns. The principle outcome of this engagement is the knowledge that our customers' reasonable expectations of reliability for the purposes of the Electricity Distribution Code are for the current average level of reliability to be maintained. However, other concerns of our customers relating to installation of air conditioners and prediction of restoration times during emergency response periods are also addressed by our Opex.

In relation to subparagraph (6), we interchange Capex with Opex to fund economically prudent non-network opportunities identified through the RIT-D process and our joint-planning memoranda of understandings (MoU).

In relation to subparagraph (7), the demand side engagement work that we have undertaken has resulted in a number of MoU being signed with demand aggregators, generators and local government to undertake joint plans to identify non-network solutions to defer network augmentations. Our plan is to avoid or defer Capex wherever possible during the forthcoming regulatory period at the time economic non-network solutions are identified and required through the joint planning MoU and RIT-D processes and to use the annualised deferral value of the Capex allowance as an Opex payment to the non-network service provider.

In relation to subparagraph (8), we are proposing to increase our demand management incentive scheme funding in the forthcoming regulatory period to build on our demand management capabilities and reduce Opex over time. We will continue to respond to the incentives provided by the EBSS in the forthcoming regulatory period.

In relation to subparagraph (9), our contracts with our service providers were competitively tendered on an arms' length basis. This was described in our Regulatory Proposal for the current regulatory period and accepted by the AER in its Distribution Determination.

In relation to subparagraph (9A), none of our Opex should be included as a contingent project.

In relation to subparagraph (10), as discussed in subparagraph (7), the identification of non-network solutions is in the very early stages, however, our plan is to avoid or defer Capex wherever possible during the forthcoming regulatory period at the time economic non-network solutions are identified and required through the joint planning MoU and RIT-D processes.

In relation to subparagraph (11), we have published one final project assessment report in relation to the Dromana Supply Area (DMA 2nd transformer). Submissions indicated there were no viable non-network solutions.

In relation to subparagraph (12), the AER has not identified to us any other relevant factors for consideration.

7.4. Key assumptions – Opex

The key assumptions underpinning our Opex forecasts are that:

- The 2014 base year is efficient but should be adjusted for customer service expectations and changes in input costs, outputs and productivity growth in the forthcoming regulatory period;
- The base year Opex should be increased for a range of additional costs (i.e. step changes) in the forthcoming regulatory period that we did not incur in the current regulatory period;
- The forecast Opex will maintain, but not improve, network reliability;
- Our current legislative and regulatory obligations will not change materially, other than as identified through the proposed step changes (being for Power of Choice, Energy Safe Victoria Regulations and the AER's RIN reporting requirements).

Our Directors have provided a certification of the reasonableness of these key assumptions in accordance with clause S6.1.2(6) of the Rules.

8. Supporting documentation

The following documents support our Opex forecast for the forthcoming regulatory period:

- BIS Shrapnel, “Real Labour and Material Cost Escalation Forecasts to 2020 – Australia and Victoria – Final Report – Report prepared for Jemena Electricity Networks Ltd, United Energy”, November 2014
- Huegin, “Benchmarking United Energy’s operating expenditure: An indication of benchmarking results using the AER’s techniques”, 22 April 2015
- PJ 03 Project Justification – CRM Solution
- PJ 12 Project Justification – Network Analytics
- PJ 19 Project Justification – Power of Choice – Consumer Data Access
- PJ 22 Project Justification – RIN Reporting
- PJ 23 Project Justification – Security Program
- PJ 25 Project Justification – Demand Management IT Platform AEMO Reporting
- PJ 26 Project Justification – Demand Management IT Platform – Demand Management
- New Strategies for the Future UE Network